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Annual Energy Outlook 2009

With Projections to 2030

For Further Information . . .

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The *Annual Energy Outlook 2009* is available on the EIA web site at www.eia.doe.gov/oiaf/aeo/. Assumptions underlying the projections, tables of regional results, and other detailed results will also be available, at web sites www.eia.doe.gov/oiaf/assumption/ and /supplement/. Model documentation reports for the National Energy Modeling System are available at web site http://tonto.eia.doe.gov/reports/reports_kindD.asp?type=model documentation and will be updated for the *Annual Energy Outlook 2009* during 2009.

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Preface

The *Annual Energy Outlook 2009* (*AEO2009*), prepared by the Energy Information Administration (EIA), presents long-term projections of energy supply, demand, and prices through 2030, based on results from EIA's National Energy Modeling System (NEMS). EIA published an "early release" version of the *AEO2009* reference case in December 2008.

The report begins with an "Executive Summary" that highlights key aspects of the projections. It is followed by a "Legislation and Regulations" section that discusses evolving legislation and regulatory issues, including a summary of recently enacted legislation, such as the Energy Improvement and Extension Act of 2008 (EIEA2008). The next section, "Issues in Focus," contains discussions of selected topics, including: the impacts of limitations on access to oil and natural gas resources on the Federal Outer Continental Shelf (OCS); the implications of uncertainty about capital costs for new electricity generating plants; and the result of extending the Federal renewable production tax credit (PTC). It also discusses the relationship between natural gas and oil prices and the basis of the world oil price and production trends in *AEO2009*.

The "Market Trends" section summarizes the projections for energy markets. The analysis in *AEO2009* focuses primarily on a reference case, low and high economic growth cases, and low and high oil price cases. Results from a number of other alternative cases also are presented, illustrating uncertainties associated with the reference case projections for energy demand, supply, and prices. 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.

AEO2009 projections are based on Federal, State, and local laws and regulations in effect as of November 2008. The potential impacts of pending or proposed legislation, regulations, and standards (and sections of existing legislation that require implementing regulations or funds that have not been appropriated) are not reflected in the projections.

AEO2009 is published in accordance with Section 205c of the Department of Energy (DOE) 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.

Projections in *AEO2009* 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 and technological and demographic trends. *AEO2009* assumes that current laws and regulations are maintained throughout the projections. Thus, the projections provide a policy-neutral baseline that can be used to analyze policy initiatives.

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. In addition, future developments in technologies, demographics, and resources cannot be foreseen with certainty. Many key uncertainties in the *AEO2009* 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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Executive Summary

The past year has been a tumultuous one for world energy markets, with oil prices soaring through the first half of 2008 and diving in its second half. The downturn in the world economy has had a significant impact on energy demand, and the near-term future of energy markets is tied to the downturn's uncertain depth and persistence. The recovery of the world's financial markets is especially important for the energy supply outlook, because the capital-intensive nature of most large energy projects makes access to financing a critical necessity.

The projections in *AEO2009* look beyond current economic and financial woes and focus on factors that drive U.S. energy markets in the longer term. Key issues highlighted in the *AEO2009* include higher but uncertain world oil prices, growing concern about greenhouse gas (GHG) emissions and its impacts on energy investment decisions, the increasing use of renewable fuels, the increasing production of unconventional natural gas, the shift in the transportation fleet to more efficient vehicles, and improved efficiency in end-use appliances. Using a reference case and a broad range of sensitivity cases, *AEO2009* illustrates these key energy market trends and explores important areas of uncertainty in the U.S. energy economy. The *AEO2009* cases, which were developed before enactment of the American Recovery and Reinvestment Act of 2009 (ARRA2009) in February 2009, reflect laws and policies in effect as of November 2008.

AEO2009 also includes in-depth discussions on topics of special interest that may affect the energy market outlook, including changes in Federal and State laws and regulations and recent developments in technologies for energy production and consumption. Some of the highlights for selected topics are mentioned in this Executive Summary, but readers interested in other issues or a fuller discussion should look at the Legislation and Regulations and Issues in Focus sections.

Developments in technologies for energy production and consumption that are discussed and analyzed in this report include the impacts of growing concerns about GHG emissions on investment decisions and how those impacts are handled in the *AEO2009* projections; the impacts of extending the PTC for renewable fuels by 10 years; the impacts of uncertainty about construction costs for electric power plants; the relationship between natural gas prices and oil prices; the economics of bringing natural gas from Alaska's North Slope to U.S. markets; expectations for oil shale production; the economics of plug-in electric hybrids; and trends in world oil prices and production.

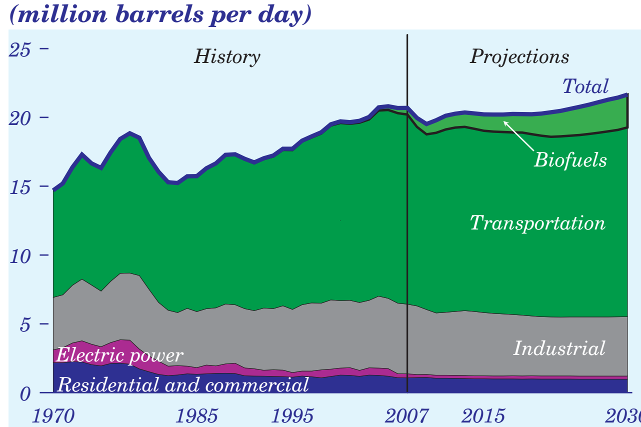
World Oil Prices, Oil Use, and Import Dependence

Despite the recent economic downturn, growing demand for energy—particularly in China, India, and other developing countries—and efforts by many countries to limit access to oil resources in their territories that are relatively easy to develop are expected to lead to rising real oil prices over the long term. In the *AEO2009* reference case, world oil prices rise to \$130 per barrel (real 2007 dollars) in 2030; however, there is significant uncertainty in the projection, and 2030 oil prices range from \$50 to \$200 per barrel in alternative oil price cases. The low price case represents an environment in which many of the major oil-producing countries expand output more rapidly than in the reference case, increasing their share of world production beyond current levels. In contrast, the high price case represents an environment where the opposite would occur: major oil-producing countries choose to maintain tight control over access to their resources and develop them more slowly.

Total U.S. demand for liquid fuels grows by only 1 million barrels per day between 2007 and 2030 in the reference case, and there is no growth in oil consumption. Oil use is curbed in the projection by the combined effects of a rebounding oil price, more stringent corporate average fuel economy (CAFE) standards, and requirements for the increased use of renewable fuels (Figure 1).

Growth in the use of biofuels meets the small increase in demand for liquids in the projection. Further, with increased use of biofuels that are produced domestically and with rising domestic oil production spurred

Figure 1. Total liquid fuels demand by sector (million barrels per day)



by higher prices in the *AEO2009* reference case, the net import share of total liquid fuels supplied, including biofuels, declines from 58 percent in 2007 to less than 40 percent in 2025 before increasing to 41 percent in 2030. The net import share of total liquid fuels supplied in 2030 varies from 30 percent to 57 percent in the alternative oil price cases, with the lowest share in the high price case, where higher oil prices dampen liquids demand and at the same time stimulate more production of domestic petroleum and biofuels.

Growing Concerns about Greenhouse Gas Emissions

Although no comprehensive Federal policy has been enacted, growing concerns about GHG emissions appear to be affecting investment decisions in energy markets, particularly in the electricity sector. In the United States, potential regulatory policies to address climate change are in various stages of development at the State, regional, and Federal levels. U.S. electric power companies are operating in an especially challenging environment. In addition to ongoing uncertainty with respect to future demand growth and the costs of fuel, labor, and new plant construction, it appears that capacity planning decisions for new generating plants already are being affected by the potential impacts of policy changes that could be made to limit or reduce GHG emissions.

This concern is recognized in the reference case and leads to limited additions of new coal-fired capacity—much less new coal capacity than projected in recent editions of the *Annual Energy Outlook* (*AEO*). Instead of relying heavily on the construction of new coal-fired plants, the power industry constructs more new natural-gas-fired plants, which account for the largest share of new power plant additions, followed by smaller amounts of renewable, coal, and nuclear capacity. From 2007 to 2030, new natural-gas-fired plants account for 53 percent of new plant additions in the reference case, and coal plants account for only 18 percent.

Two alternative cases in *AEO2009* illustrate how uncertainty about the evolution of potential GHG policies could affect investment behavior in the electric power sector. In the no GHG concern case, it is assumed that concern about GHG emissions will not affect investment decisions in the electric power sector. In contrast, in the LW110 case, the GHG emissions reduction policy proposed by Senators Lieberman and Warner (S. 2191) in the 110th Congress is incorporated to illustrate a future in which an explicit Federal policy is enacted to limit U.S. GHG emissions. The results in this case should be viewed as illustrative, because the projected impact of any policy to reduce GHG emissions will depend on its detailed specifications, which are likely to differ from those used in the LW110 case.

Projections in the two alternative cases illustrate the potential importance of GHG policy changes to the electric power industry and why uncertainty about such changes weighs heavily on planning and investment decisions. Relative to the reference case, new coal plants play a much larger role in meeting the growing demand for electricity in the no GHG concern case, and the role of natural gas and nuclear plants is diminished. In this case, new coal plants account for 38 percent of generating capacity additions between 2007 and 2030. In contrast, in the LW110 case there is a strong shift toward nuclear and renewable generation, as well as fossil technologies with carbon capture and storage (CCS) equipment.

There is also a wide divergence in electricity prices in the two alternative GHG cases. In the no GHG concern case, electricity prices are 3 percent lower in 2030 than in the reference case; in the LW110 case, they are 22 percent higher in 2030 than in the reference case.

Increasing Use of Renewable Fuels

The use of renewable fuels grows strongly in *AEO2009*, particularly in the liquid fuels and electricity markets. Overall 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 electric power generation; ethanol for gasoline blending; and biomass-based diesel—grows by 3.3 percent per year in the reference case, much faster than the 0.5-percent annual growth in total energy use. The rapid growth of renewable generation reflects the impacts of the renewable fuel standard in the Energy Independence and Security Act of 2007 (EISA2007) and strong growth in the use of renewables for electricity generation spurred by renewable portfolio standard (RPS) programs at the State level.

EISA2007 requires that 36 billion gallons of qualifying credits from biofuels be produced by 2022 (a credit is roughly one gallon, but some biofuels may receive more than one credit per gallon); and although the reference case does not show that credit level being achieved by the 2022 target date, it is exceeded by 2030. The volume of biofuels consumed is sensitive to the price of the petroleum-based products against which they compete. As a result, total liquid biofuel consumption varies significantly between the reference case projection and the low and high oil price cases. In the low oil price case, total liquid biofuel consumption reaches 27 billion gallons in 2030. In the high oil price case, where the price of oil approaches $200 per barrel (real 2007 dollars) by 2030, it reaches 40 billion gallons.

As of November 2008, 28 States and the District of Columbia had enacted RPS requirements that a specified share of the electricity sold in the State come from various renewable sources. As a result, the share of electricity sales coming from nonhydroelectric renewables grows from 3 percent in 2007 to 9 percent in 2030, and 33 percent of the increase in total generation comes from nonhydroelectric renewable sources. The share of sales accounted for by nonhydroelectric renewables could grow further if more States adopted or strengthened existing RPS requirements. Moreover, the enactment of polices to reduce GHG emissions could stimulate additional growth. In the LW110 case, the share of electricity sales accounted for by nonhydroelectric renewable generation grows to 18 percent in 2030.

Growing Production from Unconventional Natural Gas Resources

Relative to recent *AEO*s, the *AEO2009* reference case raises EIA's projection for U.S. production and consumption of natural gas, reflecting a larger resource base and higher demand for natural gas for electricity generation. Among the various sources of natural gas, the most rapid growth is in domestic production from unconventional resources, while the role played by pipeline imports and imports of liquefied natural gas (LNG) declines over the long term (Figure 2).

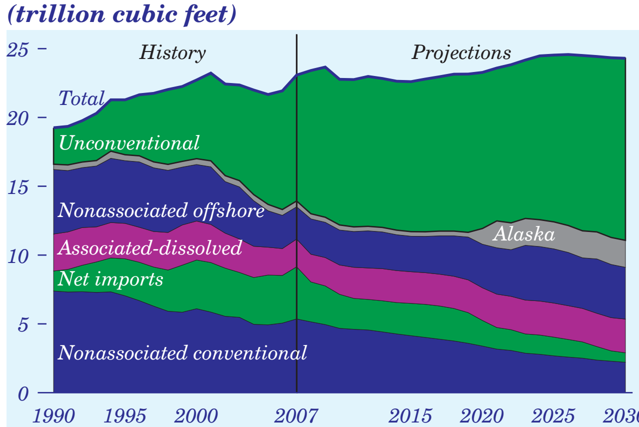
The larger natural gas resource in the reference case results primarily from a larger estimate for natural gas shales, with some additional impact from the 2008 lifting of the Executive and Congressional moratoria on leasing and development of crude oil and natural gas resources in the OCS. From 2007 to 2030, domestic production of natural gas increases by 4.3 trillion feet (22 percent), while net imports fall by 3.1 trillion cubic feet (83 percent). Although average real U.S. wellhead prices for natural gas increase from $6.39 per thousand cubic feet in 2007 to $8.40 per thousand cubic feet in 2030, stimulating production from domestic resources, the prices are not high enough to attract large imports of LNG, in a setting where world LNG prices respond to the rise of oil prices in the *AEO2009* reference case. One result of the growing production of natural gas from unconventional onshore sources, together with increases from the OCS and Alaska, is that the net import share of U.S. total natural gas use also declines, from 16 percent in 2007 to less than 3 percent in 2030.

In addition to concerns and/or policies regarding GHG emissions, the overall level of natural gas consumption that supply must meet is sensitive to many other factors, including the pace of economic growth. In the *AEO2009* alternative economic growth cases, consumption of natural gas in 2030 varies from 22.7 trillion cubic feet to 26.0 trillion cubic feet, roughly 7 percent below and above the reference case level.

Shifting Mix of Unconventional Technologies in Cars and Light Trucks

Higher fuel prices, coupled with significant increases in fuel economy standards for light-duty vehicles (LDVs) and investments in alternative fuels infrastructure, have a dramatic impact on development and sales of alternative-fuel and advanced-technology LDVs. The *AEO2009* reference case includes a sharp increase in sales of unconventional vehicle technologies, such as flex-fuel, hybrid, and diesel vehicles. Hybrid vehicle sales of all varieties increase from 2 percent of new LDV sales in 2007 to 40 percent in 2030. Sales of plug-in hybrid electric vehicles (PHEVs) grow to almost 140,000 vehicles annually by 2015, supported by tax credits enacted in 2008, and they account for 2 percent of all new LDV sales in

Figure 2. Total natural gas supply by source (trillion cubic feet)



2030. Diesel vehicles account for 10 percent of new LDV sales in 2030 in the reference case, and flex-fuel vehicles (FFVs) account for 13 percent.

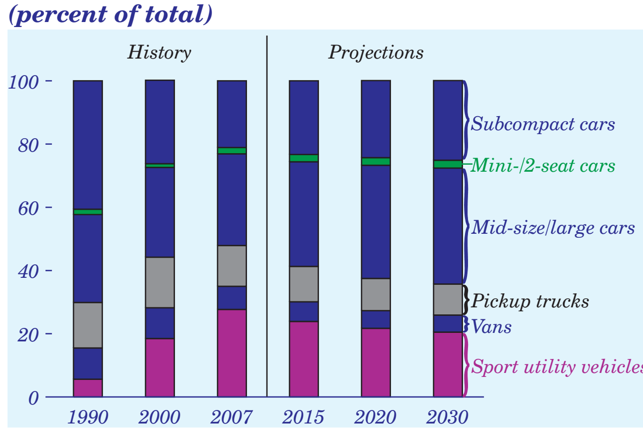
In addition to the shift to unconventional vehicle technologies, the *AEO2009* reference case shows a shift in the LDV sales mix between cars and light trucks (Figure 3). Driven by rising fuel prices and the cost of CAFE compliance, the sales share of new light trucks declines. In 2007, light-duty truck sales accounted for approximately 50 percent of new LDV sales. In 2030, their share is down to 36 percent, mostly as a result of a shift in LDV sales from sport utility vehicles to mid-size and large cars.

Slower Growth in Overall Energy Use and Greenhouse Gas Emissions

The combination of recently enacted energy efficiency policies and rising energy prices in the *AEO-2009* reference case slows the growth in U.S. consumption of primary energy relative to history: from 101.9 quadrillion British thermal units (Btu) in 2007, energy consumption grows to 113.6 quadrillion Btu in 2030, a rate of increase of 0.5 percent per year. Further, when slower demand growth is combined with increased use of renewables and a reduction in additions of new coal-fired conventional power plants, growth in energy-related GHG emissions also is slowed relative to historical experience. Energy-related emissions of carbon dioxide (CO_2) grow at a rate of 0.3 percent per year from 2007 to 2030 in the *AEO2009* reference case, to 6,414 million metric tons in 2030, compared with the *Annual Energy Outlook 2008* (*AEO2008*) reference case projection of 6,851 million metric tons in 2030.

One key factor that drives growth in both total energy consumption and GHG emissions is the rate of overall economic growth. In the *AEO2009* reference case, the U.S. economy grows by an average of 2.5 percent per year. In comparison, in alternative low and high economic growth cases, the average annual growth rates from 2007 to 2030 are 1.8 percent and 3.0 percent. In the two cases, total primary energy consumption in 2030 ranges from 104 quadrillion Btu (8.2 percent below the reference case) to 123 quadrillion Btu (8.6 percent above the reference case). Energy-related CO_2 emissions in 2030 range from 5,898 million metric tons (8.1 percent below the reference case) in the low economic growth case to 6,886 million metric tons (7.3 percent above the reference case) in the high economic growth case.

Figure 3. New light-duty vehicle sales shares by type (percent of total)



Legislation and Regulations

Legislation and Regulations

Introduction

Because baseline projections developed by EIA are required to be policy-neutral, the projections in *AEO2009* are based on Federal and State laws and regulations as of November 2008 [*1*]. 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. Throughout 2008, however, at the request of the Administration and Congress, EIA has regularly examined the potential implications of proposed legislation in Service Reports (see box below).

Examples of Federal and State legislation that has been enacted over the past few years and is incorporated in *AEO2009* include:

- The tax provisions of EIEA2008, signed into law on October 3, 2008, as part of Public Law 110-343, the Emergency Economic Stabilization Act of 2008 (see details below)
- The biofuel provisions of the Food, Conservation, and Energy Act of 2008 (Public Law 110-234) [*2*], which reduce the existing ethanol excise tax credit in the first year after U.S. ethanol production and imports exceed 7.5 billion gallons and add an income tax credit for the production of cellulosic biofuels

EIA Service Reports Released Since January 2008

The table below summarizes the Service Reports completed since 2008. Those reports, and others that were completed before 2008, can be found on the EIA web site at www.eia.doe.gov/oiaf/service_rpts.htm.

Title	*Date of release*	*Requestor*	*Availability on EIA web site*	*Focus of analysis*
Light-Duty Diesel Vehicles: Efficiency and Emissions Attributes and Market Issues	*February 2009*	*Senator Jeff Sessions*	*www.eia.doe.gov/oiaf/servicerpt/lightduty/index.html*	*Analysis of the environmental and energy efficiency attributes of LDVs, including comparison of the characteristics of diesel-fueled vehicles with those of similar gasoline-fueled, E85-fueled, and hybrid vehicles, as well as a discussion of any technical, economic, regulatory, or other obstacles to increasing the use of diesel-fueled vehicles in the United States.*
State Energy Data Needs Assessment	*January 2009*	*Required by EISA2007*	*www.eia.doe.gov/oiaf/servicerpt/energydata/index.html*	*Response to EISA2007 Section 805(d), requiring EIA to assess State-level energy data needs and submit to Congress a plan to address those needs.*
The Impact of Increased Use of Hydrogen on Petroleum Consumption and Carbon Dioxide Emissions	*September 2008*	*Senator Byron Dorgan*	*www.eia.doe.gov/oiaf/servicerpt/hydro/index.html*	*Analysis of the impacts on U.S. energy import dependence and emission reductions resulting from the commercialization of advanced hydrogen and fuel cell technologies in the transportation and distributed generation markets.*
Analysis of Crude Oil Production in the Arctic National Wildlife Refuge	*May 2008*	*Senator Ted Stevens*	*www.eia.doe.gov/oiaf/servicerpt/anwr/index.html*	*Assessment of Federal oil and natural gas leasing in the coastal plain of the Arctic National Wildlife Refuge in Alaska.*
Energy Market and Economic Impacts of S. 2191, the Lieberman-Warner Climate Security Act of 2007	*April 2008*	*Senators Joseph Lieberman, John Warner, James Inhofe, George Voinovich, and John Barrasso*	*www.eia.doe.gov/oiaf/servicerpt/s2191/index.html*	*Analysis of impacts of the greenhouse gas cap-and-trade program established under Title I of S. 2191.*
Federal Financial Interventions and Subsidies in Energy Markets 2007	*April 2008*	*Senator Lamar Alexander*	*www.eia.doe.gov/oiaf/servicerpt/subsidy2/index.html*	*Update of 1999-2000 EIA work on Federal energy subsidies, including any additions or deletions of Federal subsidies based on Administration or Congressional action since 2000, and an estimate of the size of each current subsidy.*
Energy Market and Economic Impacts of S. 1766, the Low Carbon Economy Act of 2007	*January 2008*	*Senators Jeff Bingaman and Arlen Specter*	*www.eia.doe.gov/oiaf/servicerpt/lcea/index.html*	*Analysis of mandatory greenhouse gas allowance program under S. 1766 designed to maintain covered emissions at approximately 2006 levels in 2020, 1990 levels in 2030, and at least 60 percent below 1990 levels by 2050.*

- The provisions of EISA2007 (Public Law 110-140) including: a renewable fuel standard (RFS) requiring the use of 36 billion gallons of ethanol by 2022; an attribute-based minimum CAFE standard for cars and trucks of 35 miles per gallon (mpg) by 2020; a program of CAFE credit trading and transfer; various appliance efficiency standards; a lighting efficiency standard starting in 2012; and a number of other provisions related to industrial waste heat or natural gas efficiency, energy use in Federal buildings, weatherization assistance, and manufactured housing
- Those provisions of the Energy Policy Act of 2005 (EPACT2005), Public Law 109-58, that remain in effect and have not been superseded by EISA-2007, including: mandatory energy conservation standards; numerous tax credits for businesses and individuals; elimination of the oxygen content requirement for Federal reformulated gasoline (RFG); extended royalty relief for offshore oil and natural gas producers; authorization for DOE to issue loan guarantees for new or improved technology projects that avoid, reduce, or sequester GHGs; and a PTC for new nuclear facilities
- Public Law 108-324, the Military Construction Appropriations Act of 2005, which contains provisions to encourage construction of an Alaska natural gas pipeline, including Federal loan guarantees during construction
- State RPS programs, representing laws and regulations of 27 States and the District of Columbia that require renewable electricity generation.

Examples of recent Federal and State regulations as well as earlier provisions that have been affected by court decisions that are considered in *AEO2009* include the following:

- Decisions by the D.C. Circuit Court of the U.S. Court of Appeals on February 8, 2008, to vacate and remand the Clean Air Mercury Rule (CAMR) and on July 11, 2008, to vacate and remand the Clean Air Interstate Rule (CAIR) [*3*]
- Release by the California Air Resources Board (CARB) in October 2008 of updated regulations for RFG that went into effect on August 29, 2008, allowing a 10-percent ethanol blend, by volume, in gasoline.

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

Energy Improvement and Extension Act of 2008: Summary of Provisions

The Emergency Economic Stabilization Act of 2008 (Public Law 110-343) [*4*], which was signed into law on October 3, 2008, incorporates EIEA2008 in Division B. Provisions in EIEA2008 that require funding appropriations to be implemented, whose impact is highly uncertain or that require further specification by Federal agencies or Congress, are not included in *AEO2009*. Moreover, *AEO2009* does not include any provision that addresses a level of detail beyond that modeled in NEMS. *AEO2009* addresses those provisions in EIEA2008 that establish specific tax credits and incentives, including the following:

- Extension of the residential and business tax credits for renewable energy as well as for the purchase and production of certain energy-efficient appliances, many of which were originally enacted in EPACT2005
- Removal of the cap on the tax credit for purchases of residential solar photovoltaic (PV) installations and an increase in the tax credit for residential ground-source heat pumps
- Addition of a business investment tax credit (ITC) for combined heat and power (CHP), small wind systems, and commercial ground-source heat pumps
- Provision of a tax credit for the purchase of new, qualified, plug-in electric drive motor vehicles
- Extension of the income and excise tax credits for biodiesel and renewable diesel to the end of 2009 and an increase in the amount of the tax credit for biodiesel and renewable diesel produced from recycled feedstock
- Provision of tax credits for the production of liquid petroleum gas (LPG), LNG, compressed natural gas (CNG), and aviation fuels from biomass
- Provision of an additional tax credit for the elimination of CO_2 that would otherwise be emitted into the atmosphere in enhanced oil recovery and non-enhanced oil recovery operations
- Extension and modification of key renewable energy tax provisions that were scheduled to expire at the end of 2008, including production tax credits (PTCs) for wind, geothermal, landfill gas, and certain biomass and hydroelectric facilities
- Expansion of the PTC-eligible technologies to include plants that use energy from offshore, tidal, or river currents (in-stream turbines), ocean waves, or ocean thermal gradients.

The following discussion provides a summary of the EIEA2008 provisions included in *AEO2009* 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 EIEA2008.

End-Use Demand

Residential and Commercial Buildings

EIEA2008 reinstates and extends tax credits for renewable energy and for the purchase and production of certain energy-efficient appliances, many of which were originally enacted in EPACT2005. Some of the tax credits are extended to 2016. In addition, the \$2,000 cap for residential PV purchases is removed, and the cap for ground-source heat pumps is raised from \$300 to \$2,000. The legislation also adds business ITCs for CHP, small wind systems, and commercial ground-source heat pumps.

Residential Tax Credits

EIEA2008 Titles I and III include various extensions, modifications, and additions to the tax code that have the potential to affect future energy demand in the residential sector. Sections 103 through 106 of Title I reinstate the tax credits that were implemented under EPACT2005 for efficient water heaters, boilers, furnaces, heat pumps, air conditioners, and building shell equipment, such as windows, doors, weather stripping, and insulation. The amount of the credit varies by appliance type and ranges from \$150 to \$300. The maximum credit for ground-source heat pumps, which was \$300 under EPACT2005, is \$2,000 under EIEA2008. For solar installations, which can receive a 30-percent tax credit under both EPACT-2005 and EIEA2008, the \$2,000 cap has been removed. With the cost and unit size of residential PV assumed in *AEO2009*, the credit can now reach nearly \$10,000 per unit. The tax credit for small wind generators is also extended through 2016 in EIEA2008; however, penetration of residential wind installations over the next decade is projected to be negligible.

Sections 302, 304, and 305 of EIEA2008 Title III also contain provisions that can directly or indirectly affect future residential energy demand. Section 302 adds a provision to allow a tax credit for the use of biomass fuel, which can include wood, wood pellets, and crops. In NEMS, the credit is represented as a reduction in the cost of wood stoves used as the primary space heating system. Section 304 extends the \$2,000 tax credit for new homes that are 50 percent more efficient than specified in the International Energy Conservation Code through 2009. Section 305 extends the PTC for refrigerators, dishwashers, and clothes washing machines that are a certain percentage more efficient than the current Federal standard. The duration and value of the credit vary by appliance and the level of efficiency achieved. For *AE02009*, it is assumed that the full amount of the credit is realized by consumers in the form of reduced purchase costs.

Commercial Tax Credits

Sections 103, 104, and 105 of EIEA2008 Title I extend or expand tax credits to businesses for investment in energy efficiency and renewable energy properties. Section 103 extends the EPACT2005 business ITCs (30 percent for solar energy systems and fuel cells, 10 percent for microturbines) through 2016; expands the ITC to include a 10-percent credit for CHP systems through 2016; and increases the credit limit for fuel cells from \$500 to \$1,500 per half kilowatt of capacity. Section 104 provides a 30-percent business ITC through 2016 for wind turbines with an electrical capacity of 100 kilowatts or less, capped at \$4,000. Section 105 adds a 10-percent business ITC for ground-source heat pumps through 2016. In the *AEO2009* reference case, relative to a case without the tax credits, these provisions result in a 3.2-percent increase in electrical capacity in the commercial sector by 2016.

Section 303 of EIEA2008 Title III extends the EPACT2005 tax deduction allowed for expenditures on energy-efficient commercial building property through 2013. This provision is not reflected in *AEO2009*, because NEMS does not include economic analysis at the building level.

Industrial Sector

Under EIEA2008 Title I, “Energy Production Incentives,” Section 103 provides an ITC for qualifying CHP systems placed in service before January 1, 2017. Systems with up to 15 megawatts of electrical capacity qualify for an ITC up to 10 percent of the installed cost. For systems between 15 and 50 megawatts, the percentage tax credit declines linearly with the capacity, from 10 percent to 3 percent. To qualify, systems must exceed 60-percent fuel efficiency, with a minimum of 20 percent each for useful thermal and electrical energy produced. The provision was modeled in *AEO2009* by adjusting the assumed capital cost of industrial CHP systems to reflect the applicable credit.

Section 108 extends an existing PTC, originally created under the American Jobs Creation Act of 2004 for new "refined coal" facilities producing steam coal, to those that produce metallurgical coal for the steel industry. The credit applies to coal processed with liquefied coal waste sludge and "steel industry coal" (defined as coal used for feedstock in coke manufacture). The production credit for steel industry coal is $2 per barrel of oil equivalent actually produced (equivalent to 34 cents per million Btu or $8.55 per short ton) over the first 10 years of operation for plants placed in service in 2008 and 2009. Because the *AEO2009* NEMS does not include the level of detail addressed by this tax credit, its incremental effect is not reflected in *AEO2009*. To the extent that the credit is passed on from coal suppliers as a reduction in the price of metallurgical coal, the provision would tend to reduce steel production costs and provide an incentive for domestic manufacture of coke.

Transportation Sector

EIEA2008 Title II, Section 205, provides a tax credit for the purchase of new, qualified plug-in electric drive motor vehicles. According to the legislation, a qualified plug-in electric drive motor vehicle must draw propulsion from a traction battery with at least 4 kilowatthours of capacity, use an off-board source of energy to recharge the battery, and, depending on the gross vehicle weight rating (GVWR), meet the U.S. Environmental Protection Agency (EPA) Tier II vehicle emission standards or equivalent California low-emission vehicle emission standards.

The tax credit for the purchase of a PHEV is $2,500 plus $417 per kilowatthour of traction battery capacity in excess of the minimum required 4 kilowatthours, up to a total of $7,500 for a PHEV with a GVWR of 10,000 pounds or less. The limit is raised to $10,000 for any new eligible PHEV with a GVWR between 10,000 and 14,000 pounds, $12,500 for a PHEV between 14,000 and 26,000 pounds GVWR, and $15,000 for any eligible PHEV with a GVWR greater than 26,000 pounds.

The legislation also includes a phaseout period for the tax credit, beginning two calendar quarters after the first quarter in which the cumulative number of qualified plug-in electric vehicles sold in total by all manufacturers reaches 250,000. The credit will be reduced by 50 percent in the first two calendar quarters of the phaseout period and by another 25 percent in the third and fourth calendar quarters. Thereafter, the credit will be eliminated. Regardless of calendar quarter or whether 250,000 vehicles are sold, the credit will be phased out after December 31, 2014. The tax credits for PHEVs are included in *AEO2009*.

Liquids and Natural Gas

EIEA2008 includes tax provisions that address petroleum liquids and natural gas. In Title II, "Transportation and Domestic Fuel Security Provisions, Credits for Biodiesel and Renewable Diesel," Section 202 extends income and excise tax credits for biodiesel and renewable diesel to the end of 2009. The legislation also raises the credit from 50 cents per gallon to $1 per gallon for biodiesel and renewable diesel from recycled feedstock. It also removes the term "thermal depolymerization" from the definition of renewable diesel and replaces it with "or other equivalent standard," allowing biomass-to-liquids (BTL) producers to obtain the $1 per gallon income tax credit. The legislation further specifies that the term "renewable diesel" shall include fuel derived from biomass that meets Defense Department specifications for military jet fuel or American Society for Testing and Materials specifications for aviation turbine fuel. These provisions are included in *AEO2009*.

Section 204 extends the excise tax credit for alternative fuels under Section 6426 of the Internal Revenue Code through 2009. Beginning on October 1, 2009, qualified fuel derived from coal through gasification and liquefaction processes must be produced at a facility that separates and sequesters at least 50 percent of its CO_2 emissions, increasing to 75 percent beginning in 2010. Section 204 also provides credits applicable to biomass gas versions of LPG, LNG, CNG, and aviation fuels. This provision is also included in *AEO2009*.

Coal

EIEA2008 Title I, Subtitle B, "Carbon Mitigation and Coal Provisions," modifies the tax credits available to coal consumers who sequester CO_2. In Section 111, an additional $1.25 billion is allocated to advanced coal-fired plants that separate and sequester a minimum of 65 percent of the plant's CO_2 emissions, bringing the aggregate ITC available for advanced coal projects to $2.55 billion. For this additional ITC, the allowable credit is equivalent to 30 percent of the project's qualified investment cost. Qualified investments include any expenses for property that is part of the project. For example, expenses for equipment for coal handling and gas separation would be qualifying investments if they were required for the project.

Section 112 provides an additional $250 million in ITCs for carbon sequestration equipment at qualified gasification projects, including plants producing transportation-grade liquid fuels. Eligible feedstocks for the projects include coal, petroleum residues, and biomass. To qualify for the ITC, a gasification facility must capture and sequester a minimum of 75 percent of its potential CO_2 emissions.

Section 115 of Subtitle B provides an additional tax credit for sequestration of CO_2 that would otherwise be emitted into the atmosphere from industrial sources. Tax credits of $10 per ton for CO_2 used in enhanced oil recovery and $20 per ton for other CO_2 sequestered are available. The Section 115 tax credit is limited to a total of 75 million metric tons of CO_2. In the *AEO2009* reference case, Sections 111, 112, and 115 are modeled together, resulting in 1 gigawatt of advanced coal-fired capacity with CCS by 2017.

Section 113 of Subtitle B extends the phaseout of payments by coal producers to the Black Lung Disability Trust Fund from 2013 to 2018. This provision also is modeled in the *AEO2009* reference case.

Other coal-related provisions of Subtitle B are not included in *AEO2009*, either because their effects on energy markets are minimal or nonexistent, or because they cannot be modeled directly in NEMS. They include: a provision that refunds payments to the Black Lung Disability Trust Fund for U.S. coal exports (Section 114); classification of income derived from industrial-source CO_2 by publicly traded partnerships as qualifying income (Section 116); a request for a National Academy of Sciences review of GHG provisions in the IRS Tax Code (Section 117); and a tax credit for alternative liquid fuels that is valid only through the end of 2009 (Section 204).

Renewable Energy

EIEA2008 also contains several provisions that extend and modify key tax provisions for renewable energy that were scheduled to expire at the end of 2008. Section 101 extends the PTC for wind, geothermal, landfill gas, and certain biomass and hydroelectric facilities. Wind facilities that enter service before January 1, 2010, are eligible for a tax credit of 2 cents per kilowatthour, adjusted for inflation, on all generation sold for the first 10 years of plant operation. Other eligible plants will receive the tax credit if they are on line by December 31, 2010 (but biomass plants that do not use "closed-loop" fuels [*5*] will receive a credit of 1 cent per kilowatthour).

Section 102 expands the suite of PTC-eligible technologies to include plants that use energy from offshore, tidal, or river currents (in-stream turbines), ocean waves, or ocean thermal gradients. Projects must have at least 150 kilowatts of capacity and must be on line by December 31, 2011. The PTC extension is included in *AEO2009* for all eligible technologies, with the exception of marine technologies, which are not represented in NEMS.

Section 103 extends the 30-percent ITC for business-owned solar facilities to plants entering service through December 31, 2016. The tax credit is valued at 30 percent of the initial investment cost for solar thermal and PV generating facilities that are owned by tax-paying businesses (residential owners can take advantage of tax credits discussed below; other forms of government assistance may be available to tax-exempt owners). Starting in 2017, eligible facilities will receive only a 10-percent ITC, which is not scheduled to expire. The extension through 2016 and the permanent 10-percent ITC are represented in *AEO2009*.

Section 107 authorizes continuation of the Clean and Renewable Energy Bonds (CREB) program at a level of $800 million. CREBs are issued by tax-exempt project owners (municipals and cooperatives) to raise capital for the construction of renewable energy plants. Interest on the bonds is paid by the Federal Government in the form of tax credits to the bond holders, thus providing the bond issuer with interest-free financing for qualified projects. Because NEMS assumes that all new renewable generation capacity will come from independent power producers, this provision, which targets public utilities, is not included in *AEO2009*.

Federal Fuels Taxes and Tax Credits

This section provides a review and update of the handling of Federal fuels taxes and tax credits, focusing primarily on areas for which regulations have changed or the handling of taxes or credits has been updated in *AEO2009*.

Excise Taxes on Highway Fuel

The handling of Federal highway fuel taxes remains unchanged from *AEO2008*. Consistent with current law, gasoline is assumed to be taxed at 18.4 cents per gallon, diesel fuel at 24.4 cents per gallon, and jet fuel at 4.3 cents per gallon. State fuel taxes, calculated as a volume-weighted average for diesel, gasoline, and jet fuels sold, were updated as of July 2008 [*6*]. Unlike Federal highway taxes, which remain at today's nominal levels throughout the *AEO2009* projection, State fuel taxes are assumed to remain fixed in real terms.

Biofuels Tax Credits

The only change in the handling of Federal fuels taxes and credits has been in those that pertain to biofuels. Section 15331 of the Food, Conservation, and Energy Act of 2008 reduces the existing ethanol excise tax credit of $0.51 per gallon to $0.45 per gallon in the first year after the year in which U.S. ethanol production and imports exceed 7.5 billion gallons. In the *AEO2009* projections, U.S. ethanol production and imports exceed 7.5 billion gallons in 2008, and the tax credit is reduced in 2009. The excise tax credit for ethanol is scheduled to expire at the end of 2010. In addition, Section 15321 of the Act adds an income tax credit for the production of cellulosic biofuels. The cellulosic biofuels represented in NEMS are cellulosic ethanol, BTL diesel, and BTL naphtha. The tax credit is $1.01 per gallon, but for cellulosic ethanol it is reduced by the amount of the excise tax credit available for ethanol blends (assumed to be $0.45 per gallon). The credit will be applied to fuel produced after December 31, 2008, and before January 1, 2013.

In EIEA2008, the excise tax credit of $1.00 per gallon for biodiesel, which previously was set to expire at the end of 2008, was extended through December 31, 2009. In addition, the excise tax credit of $0.50 per gallon for biodiesel made from recycled vegetable oils or animal fat is increased to $1.00 per gallon. A representation of renewable diesel—a diesel-like hydrocarbon produced by reaction of vegetable oil or animal fat with hydrogen, also known as "non-ester renewable diesel"—has been added to NEMS for *AEO2009*.

Ethanol Import Tariff

Currently, two duties are imposed on imported ethanol. The first is an *ad valorem* tariff of 2.5 percent. The second, which is a tariff of $0.54 per gallon after the application of the *ad valorem* tariff, allows for duty-free imports from designated Central American and Caribbean countries up to a limit of 7 percent of domestic production in the preceding year. The $0.54 per gallon tariff, previously set to expire on January 1, 2009, is extended to January 1, 2011, in Section 15333 of the Food, Conservation, and Energy Act of 2008. In *AEO2009*, the second tariff is assumed to expire on January 1, 2011.

New NHTSA CAFE Standards

EISA2007 requires the National Highway Traffic Safety Administration (NHTSA) to raise the CAFE standards for passenger cars and light trucks to ensure that the average tested fuel economy of the combined fleet of all new passenger cars and light trucks sold in the United States in model year (MY) 2020 equals or exceeds 35 mpg, 34 percent above the current fleet average of 26.4 mpg [*7*]. Pursuant to this legislation, NHTSA recently proposed revised CAFE standards that substantially increase the minimum fuel economy requirements for passenger cars and light trucks for MY 2011 through MY 2015 [*8*].

The new CAFE proposal builds on NHTSA's 2006 decision to use an attribute-based methodology to determine a vehicle's minimum fuel economy standard based on vehicle footprint [*9*]. The attribute-based CAFE standard uses a mathematical function that provides a unique fuel economy target for each vehicle footprint and is the same across manufacturers. Fuel economy targets are revised upward in subsequent model years to ensure improvement over time (Figures 4 and 5). Separate continuous mathematical functions are established for passenger cars and light trucks, reflecting their different design capabilities, and their combined fuel economy levels are required to reach 35 mpg by 2020.

Individual manufacturers will be required to comply with unique fuel economy levels for their car and light truck fleets, based on the distribution of their vehicle production by footprint in each model year. Individual manufacturers face different required CAFE levels only to the extent that their production distributions differ. NHTSA has estimated the impact of the new CAFE standard on the fuel economy of new LDVs and has projected that the proposed standards represent a 4.5-percent average annual increase in fuel economy between MY 2010 and MY 2015 (Table 1) [*10*]. Because the exact sales mix of different vehicle classes for a given manufacturer cannot be known until after the model year, NHTSA projects industry-wide average fuel economies for passenger cars and light trucks based on the manufacturers' production plans.

From a fuel economy average of 31.6 mpg in MY 2015, the average annual increase from MY 2015 to MY 2020 would need to be only 2 percent to reach the EISA2007 mandate of 35 mpg by 2020. Thus, NHTSA's latest proposal is heavily front-loaded, in that it requires greater gains in the first 5-year period than in the second.

Because *AEO2009* uses NHTSA's proposed CAFE standards to represent the implementation path for the fuel economy standard required by EISA2007, the average fuel economy for LDVs in the early years of the projection is higher than projected in *AEO2008* (Figure 6). In the *AEO2009* reference case, the combined fuel economy of new LDVs from MY 2011 through MY 2015 slightly exceeds NHTSA's estimated values, because *AEO2009* allows shifting of sales between cars and light trucks and among various size classes, whereas NHTSA's estimates are based on manufacturers' production plans.

NHTSA's proposal also seeks to provide added flexibility for manufacturers to meet the new CAFE standards by: (1) allowing trading of credits between manufacturers who exceed their standards and those who do not; (2) allowing credit transfers between different vehicle classes for a single manufacturer; (3) increasing from 3 to 5 the number of years during which a manufacturer can "carry forward" credits earned from exceeding the CAFE standards in earlier model years, while leaving in place the 3-year limit for manufacturers to "carry back" credits earned in later years to meet shortfalls from previous model years; and (4) extending through 2014 the ability of manufacturers to earn a maximum 1.2 mpg of CAFE credit by producing alternative-fuel vehicles, then phasing out the "carry-back" credits between 2015 and 2019.

NHTSA's flexibility provisions do not, however, allow manufacturers to miss their annual targets grossly and then make them up by using any or all of the four provisions listed above. NHTSA retains a required minimum (92 percent of the applicable CAFE standard). Before any credit can be applied by a manufacturer, its fleet of LDVs for the model year must meet an average fuel economy standard—either 27.5 mpg or 92 percent of the CAFE for the industry-wide combined fleet of domestic and non-domestic passenger cars for that model year, whichever is higher. It is important to note that NHTSA's proposed CAFE standards are subject to change in future rulemakings.

Figure 4. Proposed CAFE standards for passenger cars by vehicle footprint, model years 2011-2015 (miles per gallon)

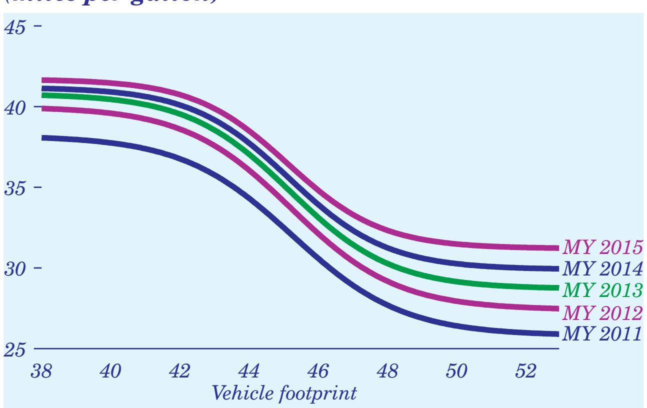
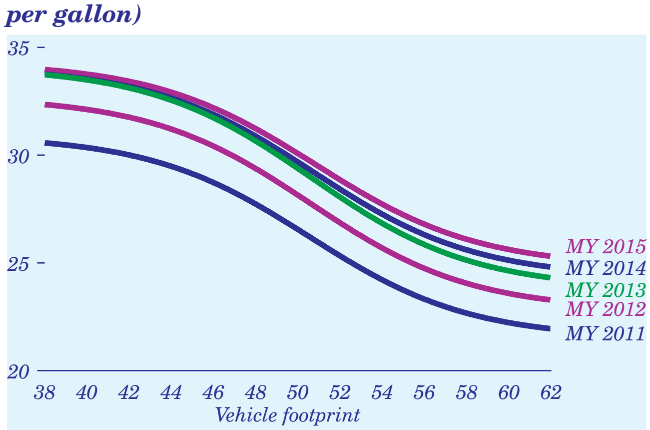


Figure 5. Proposed CAFE standards for light trucks by vehicle footprint, model years 2011-2015 (miles per gallon)



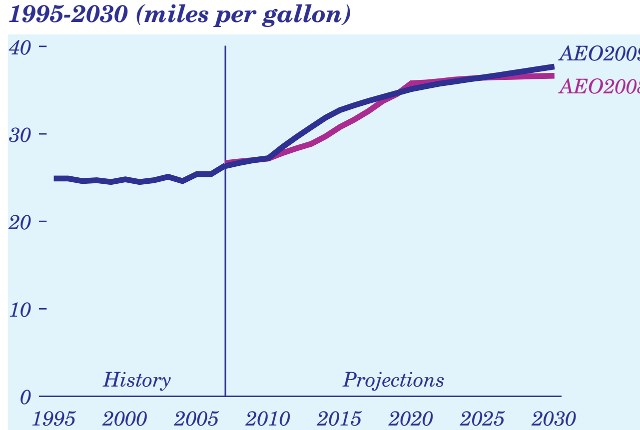
Regulations Related to the Outer Continental Shelf Moratoria and Implications of Not Renewing the Moratoria

From 1982 through 2008, Congress annually enacted appropriations riders prohibiting the Minerals Management Service (MMS) of the U.S. Department of the Interior from conducting activities related to leasing, exploration, and production of oil and natural

Table 1. Estimated fuel economy for light-duty vehicles, based on proposed CAFE standards, 2010-2015 (miles per gallon)

Model year	Passenger car	Light truck	Combined
2010	27.5	23.5	25.3
2011	31.2	25.0	27.8
2012	32.8	26.4	29.2
2013	34.0	27.8	30.5
2014	34.8	28.2	31.0
2015	35.7	28.6	31.6

Figure 6. Average fuel economy of new light-duty vehicles in the AEO2008 and AEO2009 projections, 1995-2030 (miles per gallon)



gas on much of the Federal OCS [*11*]. Further, a separate executive ban (originally put in place in 1990 by President George H.W. Bush and later extended by President William J. Clinton through 2012) also prohibited leasing on the OCS, with the exception of the Western Gulf of Mexico, portions of the Central and Eastern Gulf of Mexico, and Alaska. In combination, those actions prohibited drilling along the Atlantic and Pacific coasts, in the eastern Gulf of Mexico, and in portions of the central Gulf of Mexico. The Gulf of Mexico Energy Security Act of 2006 (Public Law 109-432) imposed yet a third ban on drilling through 2022 on tracts in the Eastern Gulf of Mexico that are within 125 miles of Florida, east of a dividing line known as the Military Mission Line, and in the Central Gulf of Mexico within 100 miles of Florida.

High oil and natural gas prices in recent years have affected policy toward oil and gas exploration and development of the OCS. On July 14, 2008, President Bush lifted the executive ban; and on September 30, 2008, Congress allowed the congressional ban to expire. Although the ban through 2022 on areas in the Eastern and Central Gulf of Mexico remains in place, lifting the executive and congressional bans removed key obstacles to development of the Atlantic and Pacific OCS.

Jurisdiction

The Submerged Lands Act (SLA) passed by Congress in 1953 established the Federal Government's title to submerged lands located on most of the OCS [*12*]. States were given jurisdiction over any natural resources within 3.45 miles (3 nautical miles) of the coastline, with the exception of Texas and the west coast of Florida, where the SLA extends the States' jurisdiction to 10.35 miles (9 nautical miles). The Outer Continental Shelf Lands Act (OCSLA), also passed in 1953, defined the OCS, separate from geologic definitions, as any submerged land outside State jurisdiction [*13*]. It also reaffirmed Federal jurisdiction over those waters and all resources therein. Further, it outlined Federal responsibilities for managing and maintaining offshore lands and authorized the Department of the Interior to formulate regulations pertaining to the leasing process and to lease the defined areas for exploration and development of OCS oil and natural gas resources.

The Coastal Zone Management Act of 1972 (CZMA) [*14*] gave States more input on activities in waters under Federal jurisdiction that affected their coastlines, encouraged coastal States to develop Coastal Zone Management Plans, and required State review of Federal actions, such as offshore leasing, that affect land and water use in their coastal areas. By virtue of the CZMA, States have the power to object to any Federal action that they deem inconsistent with their Coastal Zone Management Plan. At present, the vast majority of the U.S. coastline is covered by such plans.

MMS 5-Year Leasing Program

The OCSLA was amended in 1978 to establish specific leasing guidelines, which included the development of a 5-year leasing program. The purpose of the leasing program is to schedule all specified and proposed lease sales within a given 5-year period. The amendment also specifies a number of requirements on which the decision to include specific areas in the 5-year leasing program are to be based, including:

- Adequate information regarding the environmental, social, and economic effects of exploration and development in the area offered for lease must be considered, with no new leasing taking place if this information is not available.
- The timing and location of leasing must be based on geographic, geologic, and ecological characteristics of the region as well as location-specific risks, energy needs, laws, and stakeholder interests.
- The decisionmakers must seek balance between potential damage to the environment and coastal areas and potential energy supply.
- Areas with the greatest resource potential should have greater priority for development, particularly in areas where earlier development has proven a rich resource base.

For every 5-year leasing program, the MMS publishes a comprehensive document detailing the information and reasoning behind the leasing decisions. If a block is not included in the current 5-year leasing program, it may not be leased during the program. The first 5-year leasing program covered the period from 1980 to 1985; the current program covers the period from 2007 to 2012.

In anticipation of the possible lifting of the congressional moratorium after President Bush had lifted the executive moratorium, the MMS began initial steps toward the development of a new 5-year leasing program that would take into consideration the newly released areas. Development of the new program, which would go into effect in 2010 rather than 2012 as previously planned, began on August 1, 2008. Although its action would advance the start date for the next leasing plan by 2 years, the MMS cautioned that the development of a new 5-year leasing program remains a multi-step, multi-year process that includes three separate public comment periods, two separate draft proposals, and development of an environmental impact statement before completion of the final proposal. The final proposal must then be approved by the Secretary of the Interior. The MMS has indicated that a new 5-year leasing program could not go into effect until mid-2010, which would be the earliest that any block in the areas previously under moratoria could be offered for lease.

Leasing, Exploration, and Development

Once the 5-year leasing program is in place, the first lease sale can be offered. The actual leasing process will take 1 to 2 years, requiring preparation of draft and final environmental impact statements, periods of public comment, notices regarding the sale, approval from the governors of States bordering the area covered by the lease as mandated by the CZMA, a bidding period, the receipt and evaluation of bids, and the determination of winning bidders for each block offered for sale.

Successful bidders cannot simply begin operations when they have obtained a lease. An exploration plan must be developed and filed and must undergo technical and environmental review by the MMS before any drilling can commence. Only after obtaining the required approvals can the lease holder evaluate the area and conduct exploratory drilling, which can take from 1 to 3 years in the shallow offshore and up to 6 years in the deep offshore areas. When an initial discovery is made, a development plan must be filed for technical and environmental review by the MMS before any production can begin. Developmental drilling, along with necessary approvals, can take another 1 to 3 years. For major facilities, the MMS conducts on-site inspections, sometimes jointly with the U.S. Coast Guard, before production is allowed to begin. Air emissions permits and water discharge permits must also be obtained from the EPA. Thus, the total time required to obtain a lease, explore and develop the area, and begin actual production is between 4 and 12 years, or potentially more.

Revenue

Once awarded a lease, the lease holder pays a one-time fee plus annual rent for the right to develop the resources in the block. In addition, lease holders pay royalties to the MMS based on the value of any natural gas and oil actually produced. MMS, in turn, disburses the revenues to the appropriate Federal or State agencies. The amounts collected and distributed by the MMS in bonuses, rents, and royalties from Federal offshore oil and gas leases totaled $7.0 billion in fiscal year 2007 and $8.1 billion in fiscal year 2008 [*15*].

Under OCSLA, coastal States are entitled to 27 percent of the revenue from leases of any blocks in Federal waters that fall partially within 3 miles of the State's seaward jurisdictional boundary [*16*], a provision intended to compensate the States for any damage to or drainage from natural gas and oil resources in State waters that are adjacent to Federal leases. Between 1986 and 2003, coastal States received more than $3.1 billion in revenue from such leases [*17*].

In addition to the revenues defined by OCSLA, EPACT2005 allocated additional revenues to the States through the establishment of a new coastal impact assistance program that provides $250 million from OCS revenues per year for fiscal years 2007 to 2010 to six energy-producing coastal States: Alabama, Alaska, California, Louisiana, Mississippi, and Texas [*18*]. The Gulf of Mexico Energy Security Act of 2006 includes additional revenue-sharing provisions (for Alabama, Louisiana, Mississippi, and Texas and their coastal political subdivisions) for specific leases in the Central and Eastern Gulf of Mexico.

Future Directions

Considerable uncertainty still surrounds the issue of offshore drilling in previously restricted areas. Although the congressional moratorium was allowed to expire, some members of Congress have stated publicly that they will raise the issue again in 2009. They are joined by a number of groups and individuals who favor the moratorium and predict that it will be reinstated either partially or fully by the next Congress. Until further action is taken, however, the Atlantic and Pacific coasts are available to be leased, and offshore drilling in those areas could become a reality.

The key issue in developing the OCS is timing. A minimum of 4 years will be required before production from any new leases can begin, and many leases will require longer lead times. In addition, there is considerable uncertainty about the actual size of oil and natural gas resources in areas that have been or remain under moratorium. The actual level of technically recoverable resources also may differ from the current MMS mean resource estimate of approximately 14 billion barrels of oil and 85 trillion cubic feet of natural gas in the Atlantic and Pacific areas that were just opened for leasing. An estimated additional

3.7 billion barrels of oil and 21 trillion cubic feet of natural gas in the central and eastern Gulf of Mexico remain under moratorium through 2022 [*19*].

Loan Guarantee Program Established in EPACT2005

Title XVII of EPACT2005 [*20*] authorized DOE to issue loan guarantees to new or improved technology projects that avoid, reduce, or sequester GHGs. In 2006, DOE issued its first solicitation for $4 billion in loan guarantees for non-nuclear technologies. The issue of the size of the program was addressed subsequently in the Consolidated Appropriation Act of 2008 (the "FY08 Appropriations Act") passed in December 2008, which limited future solicitations to $38.5 billion and stated that authority to make the guarantees would end on September 30, 2009. The legislation also allocated the $38.5 billion cap as follows: $18.5 billion for nuclear plants; $6 billion for CCS technologies; $2 billion for advanced coal gasification units; $2 billion for "advanced nuclear facilities for the 'front end' of the nuclear fuel cycle"; and $10 billion for renewable, conservation, distributed energy, and transmission/ distribution technologies. DOE also was required to submit all future solicitations to both the House and Senate Appropriations Committees for approval [*21*].

DOE received all necessary approvals from Congress in the summer of 2008 and on June 30, 2008, issued two additional solicitations—one for nuclear plants and another for renewable, conservation, distributed energy, and transmission/distribution technologies [*22*, *23*]. Another solicitation, for advanced fossil fuel technologies, was issued on September 22, 2008 [*24*].

Even before it issued its 2008 solicitations, DOE had requested that Congress extend its authority to provide loan guarantees, originally set to expire at the end of fiscal year 2009, for an additional 2 years. As of November 2008, Congress had not acted on the request. Also, DOE's budget request for fiscal year 2009 indicated that only $2.2 billion in loan guarantees from the 2006 solicitation would be issued during that fiscal year. It is not clear what will happen to the rest of the program if DOE's loan guarantee authority expires as originally scheduled. *AEO2009* includes only the effects of the 2006 solicitation, which is assumed to result in the construction of 1.2 gigawatts of capacity at advanced coal-fired power plants and 250 megawatts at solar power plants [*25*].

Provisions of additional loan guarantees pursuant to the solicitations issued in 2008 could have a further effect on the projections, depending on whether the guarantees support projects that were already included in the *AEO2009* projections. For example, in October 2008 DOE received applications from 17 private and public power companies for 21 nuclear units (14 plants with a total of 28.8 gigawatts of capacity) in response to the nuclear solicitation [*26*]. In total, the utilities requested $122 billion in guarantees against total projected construction and financing costs of about $188 billion, suggesting that the $18.5 billion in the FY08 Appropriations Act could cover about 4.4 gigawatts of new nuclear capacity. *AEO2009* projects additions of 13 gigawatts of new nuclear capacity between 2000 and 2030.

Clean Air Mercury Rule

On February 8, 2008, a three-judge panel on the D.C. Circuit of the U.S. Court of Appeals issued a decision to vacate CAMR [*27*]. In its ruling, the panel cited the history of hazardous air pollutant regulation under Section 112 of the Clean Air Act (CAA) [*28*]. Section 112, as written by Congress, listed emitted mercury as a hazardous air pollutant that must be subject to regulation unless it can be proved harmless to public welfare and the environment. In 2000, the EPA ruled that mercury was indeed hazardous and must be regulated under Section 112 and, therefore, subjected to the best available control technology for mitigation.

CAMR was promulgated under Section 111 of the CAA, which allows for the use of a cap-and-trade approach rather than implementation of best available control technology. The EPA had delisted mercury from Section 112 without making the necessary findings to show that mercury emissions could be regulated under Section 111 without harming human health or the environment. The panel stated that the EPA overstepped its authority by ignoring Congressional guidelines and the agency's own earlier findings.

With the elimination of CAMR, there is no Federal mandate to regulate mercury emissions. Even before the rule was vacated, however, many States were adopting more stringent regulations that were allowed through an EPA waiver. Most of those regulations called for the application of best available control technology on all electricity generating units of a certain capacity. After the court's decision, more States imposed their own regulations.

At the time *AEO2009* was published, roughly one-half of the States, including most of those in the Northeast, had their own mercury mitigation laws in place. Without Federal monitoring requirements, however, some of the States that had previously passed regulations may have to make modest modifications in their guidelines. At present, electricity generating units in States without mercury laws are free to emit without limitations. Because the State laws differ, a rough estimate was created that generalized the various State programs into a format that could be used in NEMS, including a rough estimate of mercury emissions within each State. Moreover, the regulatory environment is extremely fluid, with many States planning to enact new laws or make their existing laws more stringent.

Clean Air Interstate Rule

CAIR is a cap-and-trade program promulgated by the EPA in 2005, covering 28 eastern U.S. States and the District of Columbia [*29*]. It was designed to reduce sulfur dioxide (SO_2) and nitrogen oxide (NO_x) emissions in order to help States meet their National Ambient Air Quality Standards (NAAQS) for ozone and particulate matter ($PM_{2.5}$) and to further emissions reductions already achieved through the Acid Rain Program and the NO_x State Implementation Plan call program. The rule was set to commence in 2009 for seasonal and annual NO_x emissions and in 2010 for SO_2 emissions.

On July 11, 2008, the U.S. District Court of Appeals court unanimously overturned CAIR, ruling that it could not be implemented under the CAA [*30*]. Electric utilities were caught off guard by the court's decision to vacate CAIR. Because the rule was less than 2 years away from implementation, many power plant owners already had spent billions of dollars on pollution control equipment [*31*]. In addition, many States were relying on reductions from CAIR to meet their NAAQS for $PM_{2.5}$ and ozone, and without the rule they might not be able to meet those requirements. The price of seasonal NO_x and SO_2 emissions allowances dropped significantly after the decision. The value of SO_2 allowances has fallen by 75 percent in 2008, and because there is no market for annual NO_x emissions allowances without CAIR, their price has dropped to zero.

Several actions are pending. On September 24, 2008, the U.S. Department of Justice (DOJ) and the EPA, along with several industry representatives and environmental groups, filed petitions in the Court of Appeals asking for the case to be reheard [*32*]. In the petition, the DOJ claimed that the statement in the court's decisions that CAIR was "fundamentally flawed" was incorrect. It also claimed that vacating CAIR could potentially "result in serious harms." The court is considering their petition. On October 21, 2008, the court asked for briefs from the main plaintiffs in the case, specifically asking whether they thought CAIR should be reinstated on an interim basis until updated regulations are issued [*33*]. This development raises the possibility that such a reinstatement could occur.

On December 23, 2008, the Court of Appeals issued a new ruling that remanded but did not vacate CAIR, noting that: "Allowing CAIR to remain in effect until it is replaced by a rule consistent with our opinion would at least temporarily preserve the environmental values" [*34*]. The change allows the EPA to modify CAIR to address the objections raised by the Court in its earlier decisions while leaving the rule in place. Because the ruling came well after the cutoff date for changes in Federal and State laws and regulation to be included in *AEO2009*, it is not reflected in the projections. Nonetheless, States still are required to meet their NAAQS, which will require emissions reductions. Therefore, it is assumed that all emissions limits in effect under CAIR remain in effect in the *AEO2009* reference case, but without the CAIR allowance trading provisions.

State Appliance Standards

State appliance standards have existed for decades, starting with California's enforcement of minimum efficiency requirements for refrigerators and several other products in 1979. In 1987, recognizing that different efficiency standards for the same products in different States could create problems for manufacturers, Congress enacted the National Appliance Energy Conservation Act (NAECA), which initially covered 12 products. The Energy Policy Act of 1992 (EPACT92), EPACT2005, and EISA2007 added additional residential and commercial products to the 12 products originally specified under NAECA.

Many different State appliance standards still exist today (Table 2); however, a key point of NAECA was to enforce Federal preemption of any State appliance standard. The preemption clause allows States to continue to mandate standards for products not covered by Federal law and to enforce standards that might have existed before Federal coverage, up to the date of Federal enforcement. Because most major appliances are covered by Federal law, the majority of State standards target less energy-intensive products. Most of the standards for products listed in Table 2 will be preempted by Federal standards within the next decade. For example, the California standard for general-service lighting will be preempted in 2012 by the Federal standard for general-service lighting required in EISA2007. States can petition DOE for a waiver to continue to enforce their own standards, as opposed to a less strict Federal standard. To date, however, no waivers have been granted.

The NEMS residential and commercial modules represent Federal appliance standards for all major appliances covered under NAECA and subsequent legislation. For products not explicitly covered in NEMS (residential dehumidifiers, for example), an off-line estimate of the impact of the standard is included in the projections by way of deducting the savings estimates from the projections without the standards included. Given that the NEMS buildings

Table 2. State appliance efficiency standards and potential future actions

State	Program (effective year of standard noted in parentheses)
AZ	Arizona's Minimum Appliance and Equipment Efficiency Standards currently apply to automatic commercial icemakers (2008) and metal halide lamp fixtures (2008). Every 3 years, the Energy Office of the Arizona Department of Commerce must conduct a comparative review and assessment of standards and submit a report of its findings and recommendations to the State legislature.
CA	California's Appliance Efficiency Regulations apply to automatic commercial ice makers (2006); commercial refrigerators and freezers (2003 phase I / 2006 phase II); consumer audio and video products (2006/2007); large packaged air conditioners above 20 tons (2006/2010); metal halide lamp fixtures (2006/2008); pool pumps (2006/2008); single-voltage external power supplies (2007/2008); general service incandescent lamps (2006); water dispensers (2003); walk-in refrigerators and freezers (2006); hot tubs (2006); commercial hot food holding cabinets (2006); under-cabinet fluorescent lamps (2006); and vending machines (2006). In addition, Assembly Bill 1109 requires a minimum efficiency standard for all general-purpose lights, with the goal of reducing energy use for indoor residential lighting to 50 percent of 2007 levels and for indoor commercial and outdoor lighting to 75 percent of 2007 levels by 2018.
CT	Connecticut efficiency standards apply to commercial refrigerators and freezers (2008) and large packaged air-conditioning equipment (2009). Standards must be reviewed biannually and increased if it is determined that higher efficiency standards would promote energy conservation and be cost-effective for consumers, and if multiple products would be available.
MD	Maryland's efficiency standards apply to bottle-type water dispensers (2009); commercial hot food holding cabinets (2009); metal halide lamp fixtures (2009); residential furnaces (2009); alternating current to direct current power supplies (2012/2013); State-regulated incandescent reflector lamps (2009); walk-in refrigerators and freezers (2009); commercial refrigeration cabinets (2010); and large packaged air-conditioning equipment (2010). Every 2 years the Maryland Energy Administration is directed to review and propose new standards to the Maryland Assembly for products not already subject to standards, or add more stringent amendments to existing standards.
MA	The Massachusetts appliance standards currently apply to medium-voltage dry-type transformers (2008); metal halide lamp fixtures (2009); residential furnaces and boilers (to be determined); residential furnace fans (to be determined); State-regulated incandescent reflector lamps (various types) (2008); and single-voltage external power supplies (2008). The State Department of Energy Resources (DOER) must file a biannual report on appliance efficiency standards, evaluating effectiveness and energy conservation. Existing Federal standards cover residential furnaces, boilers, and furnace fans; however, Massachusetts is seeking a waiver from the warm weather standard.
NV	Nevada's Assembly Bill 178 establishes efficiency standards for general-purpose lights (lamps, bulbs, tubes, or other illumination devices for indoor and outdoor use, not including lighting for people with special needs) to take effect between 2012 and 2015. Effective January 1, 2016, the Director of the Office of Energy must set a new minimum efficiency standard that exceeds the previous standard.
NY	New York efficiency standards currently not preempted by Federal legislation include consumer audio and video products (to be determined); digital television adapters (to be determined); metal halide lamp fixtures (2008); and single-voltage external power supplies (to be determined, preemption for some types starting in July 2008). New York law allows the Secretary of State, in consultation with the State Energy Research and Development Authority, to add additional products so long as they are commercially available, cost-effective, and not covered by Federal standards.
OR	Oregon efficiency standards currently not preempted by Federal legislation include automatic commercial icemakers (2008); metal halide fixtures (2008); single-voltage external power supplies (2007); and State-regulated incandescent reflector lamps (various types) (2007).
RI	Rhode Island efficiency standards not preempted by Federal standards include high-intensity discharge lamp ballasts (2007); single-voltage external power supplies (2008); metal halide lamp fixtures (2008); residential boilers and furnaces (to be determined); incandescent spot lights (2008); bottled water dispensers (2008); commercial hot food holding cabinets (2008); and walk-in refrigerators and freezers (2008). Rhode Island legislation allows for existing efficiency standards to be increased if the Chief of Energy and Community Services determines that it would promote energy conservation in the State and would be cost-effective for consumers.
VT	Vermont's Act Relating to Establishing Energy Efficiency Standards for Certain Appliances creates minimum standards for medium-voltage dry-type transformers (2008); metal halide lamp fixtures (2009); residential furnaces and boilers (to be determined); residential furnace fans (to be determined); single-voltage external power supplies (2008); and State-regulated incandescent reflector lamps (various types) (2008).
WA	Washington standards apply to automatic commercial ice makers (2008); commercial refrigerators and freezers (2007); metal halide lamp fixtures (2008); single-voltage external power supplies (2008); and State-regulated incandescent reflector lamps (various types) (2007). State efficiency legislation stipulates that standards may be increased or updated.

modules are specified at the Census Division level, State standards are not readily amenable to direct modeling in NEMS. Furthermore, the paucity of data at the State level does not allow for a direct accounting of equipment stock or energy usage, which is needed to estimate energy savings. Although NEMS does not represent State appliance standards explicitly, recent trends in energy intensity are taken into account in the projections and should represent recent State appliance efficiency standards to the extent that they affect future energy demand in the buildings sectors.

California's Move Toward E10

In *AEO2009*, E10—a gasoline blend containing 10 percent ethanol—is assumed to be the maximum ethanol blend allowed in California RFG, as opposed to the 5.7-percent blend assumed in earlier *AEO*s. The 5.7-percent blend had reflected decisions made when California decided to phase out use of the additive methyl tertiary butyl ether in its RFG program in 2003, opting instead to use ethanol in the minimum amount that would meet the requirement for 2.0 percent oxygen content under the CAA provisions in effect at that time [*35*].

Recently, there has been a push in California to increase the use of ethanol, for two reasons. First, the RFS mandate in EISA2007 Title II, Subtitle A [*36*], requires greater use of renewable fuels, such as ethanol. Second, California's Low Carbon Fuel Standard (LCFS) mandates a reduction in the State's overall GHG emissions to 1990 levels by 2020 and require a 10-percent reduction in GHG emissions from passenger vehicles by 2020. Although fuel providers can use a variety of strategies to produce lower carbon fuel, increasing the ethanol blends from 5.7 percent to 10 percent is thought to be a first step toward achieving the LCFS goals. In fact, in October 2008, CARB released its first draft of the LCFS regulatory framework [*37*]. The calculation in the framework assumes that the baseline emissions for gasoline in 2010 (from which CO_2 emissions must be reduced in later years) will be from E10 (California RFG with 10 percent ethanol content), implying that most, if not all, gasoline sold in California by 2010 will be E10.

Modifications were made to California's RFG regulations and the predictive model that estimates emissions for different fuel mixes in order to increase ethanol blends above 5.7 percent. The predictive model was revised to accommodate the higher ethanol blends in determining evaporative and exhaust emissions, providing the information needed by fuel providers to increase ethanol content. For example, the increased ethanol content will result in higher NO_x emissions, and the increase must be mitigated by lowering the fuel's sulfur content.

Refineries in California may have to make substantial modifications to produce compliant fuel under the new standards (most significantly, producing fuel with only 5 parts per million sulfur), and all fuel sold in California must be compliant with the new CARB Phase 3 standards after December 31, 2009. The final approved modifications in CARB Phase 3 gasoline and the revisions in the predictive model provide refiners and importers of fuel a formal framework with which to provide compliant fuel. Already, at least one major refiner has stated that it will apply the amended CARB Phase 3 gasoline standards, presumably to increase ethanol content.

State Renewable Energy Requirements and Goals: Update Through 2008

State RPS programs continue to play an important role in *AEO2009*, growing in number while existing programs are modified with more stringent targets. In total, 28 States and the District of Columbia now have mandatory RPS programs (Table 3), and at least 4 other States have voluntary renewable energy programs. In the absence of a Federal renewable electricity standard, each State determines its own levels of generation, eligible technologies, and noncompliance penalties. The growth in State renewable energy requirements has led to an expansion of renewable energy credit (REC) markets, which vary from State to State. Credit prices depend on the State renewable requirements and how easily they can be met.

In the *AEO2009* reference case, most States are projected to meet their RPS targets. California is an exception, as a result of limits on State funding for renewable projects. Therefore, for California, the cost of achieving each target increment is estimated, and the amount of renewable capacity that exhausts the renewable funding is assumed to be built. Renewable generation in most regions is approximated, because NEMS is not a State-level model, and each State represents only a portion of one of the NEMS regions. Compliance costs in each region are tracked, and the projection for total renewable generation is adjusted as needed to be consistent with the individual State provisions.

Table 3. State renewable portfolio standards

State	Program mandate
AZ	Arizona Corporate Commission Decision No. 69127 requires 15 percent of electricity sales to be renewable by 2025, with interim goals increasing annually. A specific percentage of the target must be from distributed generation. Multiple credits may be given for solar generation and in-State manufactured systems.
CA	Public Utilities Code Sections 399.11-399.20 mandate that 20 percent of electricity sales must be renewable by 2010. There are also goals for the longer term. Renewable projects with above-market costs will be funded by supplemental energy payments from a fund, possibly limiting renewable generation to less than the 20-percent requirement.
CO	House Bill 1281 sets the renewable target for investor-owned utilities at 20 percent by 2020. There is a 10-percent requirement in the same year for cooperatives and municipals. Moreover, 2 percent of total sales must be from solar power. In-State generation receives a 25-percent credit premium.
CT	Public Act 07-242 mandates a 27-percent renewable sales requirement by 2020, including a 4-percent mandate from higher efficiency or CHP systems. Of the overall total, 3 percent may be met by waste-to-energy facilities and conventional biomass.
DE	Senate Bill 19 determined the RPS to be 20 percent of sales by 2019. There is a separate requirement for solar generation (2 percent of the total), and compliance failure results in higher penalty payments. Solar technologies receive triple credits, and offshore wind receives 3.5 times the credit amount.
HI	Senate Bill 3185 sets the renewable mandate at 20 percent by 2020. All existing renewable facilities are eligible to meet the target, which has two interim milestones.
IL	Public Act 095-0481 created an agency responsible for overseeing the mandate of 25-percent renewable sales by 2025. There are escalating annual targets. and 75 percent of the requirements must be generated from wind. The plan also includes a cap on the incremental costs added from renewable penetration.
IA	An RPS mandating105 megawatts of renewable energy capacity has already been exceeded.
ME	In 2007, Public Law 403 added to the State's RPS requirements. Originally, a mandate of 30 percent renewable generation by 2000 was set to be lower than current generation. The new law requires a 10-percent increase in renewable capacity by 2017, and that level must be maintained in subsequent years. The years leading up to 2017 also have new capacity milestones.
MD	House Bill 375 revised the RPS to contain a 20-percent target by 2022, including a 2-percent solar target. Penalty payments for "Tier 1" compliance shortfalls were also raised to 4 cents per kilowatthour under the same legislation.
MA	The RPS has a goal of a 4-percent renewable share of total sales by 2009, with subsequent 1-percent annual increases to 2014. The State also has necessary payments for compliance shortfalls.
MI	Public Act 295 established an RPS that will require 10 percent renewable generation by 2015. Bonus credits are given to solar energy.
MN	Senate Bill 4 created a 30-percent renewable requirement by 2020 for Xcel, the State's largest supplier, and a 25-percent requirement by 2025 for others. Also specified was the creation of a State cap-and-trade program that will assist the program's implementation.
MO	Proposition C, approved by voters, mandates a 2-percent renewable energy requirement in 2011, which will increase incrementally to 15 percent of generation by 2021. Bonus credits are given to renewable generation within the State.
MT	House Bill 681 expanded the RPS provisions to all suppliers. Initially the law covered only public utilities. A 15-percent share of sales must be renewable by 2015. The State operates a REC market.
NV	The State has an escalating renewable target, established in 1997 and revised in 2005, that reaches 20 percent of total electricity sales by 2015. Up to one-quarter may be met through efficiency measures. There is also a minimum requirement for PV systems, which receive bonus credits.
NH	House Bill 873 legislated that 23.8 percent of electricity sales must be renewable by 2025, and 16.3 percent of total sales must be from renewable facilities that begin operation after 2006. Compliance penalties vary by generation type.
NJ	In 2006, the RPS was revised to increase renewable energy targets. The current level for renewable generation is 22.5 percent of sales by 2021, with interim targets. There are different requirements for different technologies, including a 2-percent solar mandate.
NM	Senate Bill 418 directs investor-owned utilities to have 20 percent of their sales from renewable generation by 2020. The renewable portfolio must consist of diversified technologies, with wind and solar each accounting for 20 percent of the target. There is a separate standard of 10 percent by 2020 for cooperatives.
NY	The Public Service Commission issued RPS rules in 2005 that call for an increase in renewable electricity sales to 24 percent of the total by 2013, from the current level of 19 percent. The program is administered and funded by the State.
NC	Senate Bill 3 created an RPS of 12.5 percent by 2021 for investor-owned utilities. There is also a 10-percent requirement by 2018 for cooperatives and municipals. Through 2018, 25 percent of the target may be met through efficiency standards, increasing to 40 percent in later years.
OH	Senate Bill 221 requires 25 percent of electricity to be produced from alternative energy resources by 2025, including low-carbon and renewable technologies. One-half of the target must come from renewable sources. Municipals and cooperatives are exempt.
OR	In June 2007, Senate Bill 838 required renewable targets of 25 percent by 2025 for large utilities and 5 to 10 percent by 2025 for smaller utilities. Any source of renewable electricity on line after 1995 is considered eligible. Compliance penalty caps have not yet been determined.
PA	The Alternative Energy Portfolio Standard has an18-percent requirement by 2020. Most of the qualifying generation must be renewable, but there is also a provision that allows certain coal resources to receive credits.
RI	The program requires that 16 percent of total sales be renewable by 2020. The interim program targets escalate more rapidly in later years. If the target is not met, a generator must pay an alternative compliance penalty.

(continued on page 22)

Table 3. State renewable portfolio standards (continued)

State	*Program mandate*
TX	*Senate Bill 20 strengthened the State RPS by mandating 5,880 megawatts of renewable capacity by 2015. There is also a target of 500 megawatts of renewable capacity other than wind.*
WA	*Voters approved Initiative 937, which specifies that 15 percent of sales from the State's largest generators must come from renewable sources by 2020. There is an administrative penalty of 5 cents per kilowatthour for noncompliance. Generation from any facility that came on line after 1999 is eligible.*
WI	*Senate Bill 459 strengthened the State RPS with a requirement that, by 2015, each utility's renewable share of total generation must be at least 6 percentage points above the renewable share from 2001 to 2003. There is also a non-binding goal.*

In 2008, three States (Michigan, Missouri, and Ohio) enacted new renewable legislation, and three others (Delaware, Maryland, and Massachusetts) modified existing legislation. Missouri's new RPS was approved by voters in the November 2008 election. In California, voters rejected two propositions that would have strengthened the State RPS. One would have increased the renewable requirement to 50 percent of electricity generated by 2025 and allowed for the use of a 20-year feed-in tariff [*38*]; the other would have established a $5 billion fund to support renewable electricity generation and transportation projects. The propositions were not supported by many environmentalists, who saw them as poorly written and potentially causing harm to the renewable industry. Both were defeated easily.

Michigan. Public Act 295 [*39*] established Michigan's first RPS. Signed into law in October 2008, the Act requires that all electricity suppliers generate 10 percent of their electricity from renewable sources by 2015. There are also intermediate benchmarks. Each supplier has its own standard, based on current levels of renewable generation. Coal-fired plants that sequester at least 85 percent of their emissions also qualify toward the target, as do all renewable technologies except new hydroelectric facilities; however, improvements on existing hydroelectric facilities will receive energy credits. Like most programs, Michigan's RPS will use RECs to promote compliance. Bonus credits are given to solar generators as well as facilities using in-State labor and manufactured equipment [*40*]. Up to 10 percent of the total requirement may be met through energy optimization and advanced system credits, which lower electricity demand.

Missouri. On November 4, 2008, voters approved Proposition C [*41*], changing Missouri's renewable goal into an enforceable mandate. The requirement goes into effect in 2011 with a 2-percent renewable target, which increases in four phases to reach the final 15-percent target by 2021. REC trading will be used, with in-State renewable generation eligible for 1.25 REC for each megawatthour of electricity generated. A small percentage of the overall renewable requirement must be met through solar generation. Suppliers subject to the RPS are required to offer their retail costumers a rebate of $2.00 per installed watt of small-scale solar systems.

Ohio. In May 2008, Ohio enacted legislation [*42*] that requires most retail electricity providers to produce 25 percent of their electricity from alternative energy resources by 2025. Alternatives are defined as low-carbon technologies, including nuclear energy and coal with carbon sequestration. Plants that come on line after 1998 are considered eligible toward meeting the target. Within the 25-percent requirement is a separate provision that increases the required renewable share of annual generation from 0.25 percent in 2009 to 12.5 percent in 2024. There are also energy efficiency and load-reducing requirements. Municipal and cooperative suppliers are exempt from all provisions.

REC trading is expected to help Ohio achieve its requirements. The REC prices will be capped at $45 per megawatthour, with more severe penalties incurred if the solar requirement is not met; however, there is also a provision that exempts suppliers from the mandates if they can show that they would incur incremental costs 3 percent above the total cost of a conventional alternative. Suppliers exempted from the annual requirement may have to meet stiffer compensatory targets in subsequent years.

Delaware. Senate Bill 328 [*43*] amended Delaware's existing RPS by awarding offshore wind 3.5 times as many credits as are received by conventional renewable technologies toward meeting the mandate. Analysis has shown that this provision makes offshore wind development economical under business-as-usual assumptions.

Maryland. House Bill 375 [*44*] increased the State's renewable energy requirement to 20 percent of total generation by 2022. The requirement must be met with resources classified in the legislation as "tier 1," which include all renewable forms of generation except existing large hydroelectric facilities. Senate Bill 348 [*45*], also enacted in 2008, expanded the definition of tier 1 resources to include "poultry litter-to-energy" facilities. Also included in the tier 1 resource target is a solar energy mandate that increases annually until it reaches 2 percent in 2022. Smaller amounts of electricity generated from tier 2 resources (large hydropower facilities) are included until 2019.

Along with its increased mandatory target, House Bill 375 includes higher compliance caps. A shortfall in renewable generation from tier 1 resources other than solar energy will cost a supplier 4 cents per kilowatthour. If it can be shown, however, that achieving the target would cost more than one-tenth of the supplier's total energy sales, the target may be deferred until the next year (an "off-ramp" that was added with the higher compliance caps in House Bill 375). Penalties for solar shortfalls are much larger, 45 cents per kilowatthour in the initial shortfall year, but they decrease by 5 cents annually until they reach and remain at 5 cents per kilowatthour beginning in 2023. Funds generated from the penalties will go to an energy investment fund for support of renewable energy technology advancement and deployment.

Massachusetts. The State RPS requirements are modeled through 2014 in *AEO2009*. Electricity suppliers in Massachusetts are required to increase their annual renewable generation from 4 percent of total generation in 2009 to 9 percent in 2014. The State DOER has the option of extending the 1-percent annual increase through 2020. Renewable requirements beyond 2014 are not assumed in *AEO2009*. In December 2008, the DOER enacted regulations establishing a target of 15 percent renewable generation by 2020, with the presumption of increasing the target thereafter. *AEO2009* is based on regulations in effect as of November 2008 and does not include the new target.

Updated State Air Emissions Regulations

Regional Greenhouse Gas Initiative

In September 2008, the first U.S. mandatory auction of CO_2 emission permits occurred among six States in the Northeast that are part of the Regional Greenhouse Gas Initiative (RGGI). The RGGI program includes 10 Northeastern States that have agreed to curtail and reverse growth in CO_2 emissions. It covers all electricity generating units with a capacity of at least 25 megawatts and requires them to hold an allowance for each ton of CO_2 emitted [*46*].

The first year of mandatory compliance is 2009 and each State's CO_2 "carbon budget" already has been determined. The budgets consist of historically based baselines with a cushion for emissions growth, so that meeting the cap is expected to be relatively easy initially and become more difficult over time. Overall, the RGGI region must maintain emissions of 188 million tons CO_2 for the next 5 years, followed by a mandatory 2.5-percent annual decrease through 2018, when the CO_2 emissions level should be 10 percent below the initial calculated budget. The requirements are expected to cover 95 percent of CO_2 emissions from the region's electric power sector. Each State has its own emissions budget, and the allowances will be auctioned at a uniform price across the entire region.

Before the first auction, several rules were agreed to by the States:

- Auctions will be held quarterly, following a single-round, sealed-bid format.
- Allowances will be sold at a uniform price, which is the highest price of the rejected bids.
- States may hold a small number of allowances for their own use; however, most States have decided to auction all their allowances.
- Each emitter must buy one allowance for every ton of CO_2 emitted.
- Future allowances will be made available for purchase up to 4 years before their official vintage date, as a way to control price fluctuations.
- A reserve price of $1.86 per allowance in real dollars will be in effect for each auction, as a way to preserve allowance prices in auctions where demand is low and to avoid collusion among emitters that could threaten a fair market.
- The revenue from the auctions can be spent at the State's discretion, although at least 25 percent must go to a fund that benefits consumers and promotes low-carbon energy development.

In the first auction, the six participating States (Connecticut, Maine, Maryland, Massachusetts, Rhode Island, and Vermont) sold 12,600,000 allowances at a price of $3.07 per allowance [*47*]. The next auction, held in December 2008, included the original six States along with New York, New Jersey, New Hampshire, and Delaware. Issues such as emission leakage [*48*], which is especially relevant in the Mid-Atlantic region, have been studied, but no specific solutions have been implemented.

RGGI is included in the *AEO2009* reference case. The effect is minimal in the early years, given the relatively generous emissions budget. Because it is difficult to capture the nuances of State initiatives in NEMS, which is a regional model, independent estimates were made for the Mid-Atlantic region to determine eligible generation facilities and their emissions caps (for Pennsylvania, an observing member that it is not participating in the cap-and-trade program and is not subject to any mandatory reductions, emissions are not restricted).

Western Climate Initiative

Developed independently of RGGI, the Western Climate Initiative (WCI) [*49*] is also a regional GHG reduction program. Participants in the WCI include seven U.S. States (Arizona, California, Montana, New Mexico, Oregon, Utah, and Washington) and four Canadian Provinces, with additional observer States and provinces in the United States, Canada, and Mexico.

The WCI seeks to reduce GHG emissions to levels 15 percent below 2005 emissions by 2020. Reductions will be achieved through an allowance cap-and-trade program, and each participating State or province will be able to determine its own allowance allocation method. Allowances will be based on a regionally agreed emissions estimate, likely taking into account some growth in GHG emissions through the first year of mandatory compliance in 2012. Although each jurisdiction will choose the specifics of allowance distribution, a minimum of 10 percent of allowances must be auctioned in 2012, and the requirement rises in subsequent years. In the initial compliance year, electricity generators and large industrial facilities in the WCI region, as well as outside facilities with energy products consumed in the region, will be required to provide one allowance for each ton of CO_2 equivalent released into the atmosphere.

WCI is similar to RGGI, but they also have important differences. Although the first phase of the WCI program (2012 to 2015) will not cover emissions from fossil fuels used in smaller facilities or in mobile sources, all fuels are expected to be covered by 2015, including those used in the transportation, industrial, and residential sectors (none of which is covered by RGGI in any period). All fuels will be regulated upstream at the distributor level. The 2015 cap will grow above the first phase cap, which covers only facilities emitting more than 10,000 tons CO_2 equivalent annually. Those sources will continue to be covered after the inclusion of combustion fuels, but the emissions will not be counted twice. Larger stationary facilities will be regulated at the emission source, and their fuels will not be subject to upstream regulation. Mandatory emissions monitoring of the stationary sources will begin in January 2010.

Another distinction is that the WCI will account for nitrous oxide, methane, hydrofluorocarbons, perfluorocarbons, and sulfur hexafluoride, not just CO_2 as in RGGI. The additional GHGs will be measured in terms of their CO_2-equivalent global warming potentials, and allowances will be issued accordingly. WCI documents estimate that 90 percent of the region's GHG emissions will be subject to regulation after additional combustion fuels are included in 2015.

Although no final caps have been determined, the permissible GHG ceiling will decline over the program, which currently ends in 2020. No formal determination of how to continue the program beyond 2020 has been made. In order to control the price of allowances, a reserve price will be set as the floor. Up to 49 percent of emissions reductions may occur through offset programs such as forestation and agriculture reform. The list of qualifying offsets remains to be determined but must be agreed on by all participants. There are still some details to be worked out between the WCI and the individual jurisdictions within the region that have their own GHG mitigation laws. Two prime examples are California, which has passed its own GHG legislation, and British Columbia, which is mitigating emissions through a tax. The issues will be addressed after the specifics of the program have been determined.

Unlike RGGI, the WCI is not included in the *AEO-2009* reference case, because the WCI model rules were released after November 2008. Similarly, the Midwestern Climate Initiative, which is in a preliminary stage, is not included in *AEO2009*. Regional and State GHG initiatives continue to evolve rapidly, and it is likely that *AEO2010* will include additional programs.

Endnotes for Legislation and Regulations

1. Including several ballot initiatives for energy-related legislation, where the results of the balloting are known.
2. For the complete text of the Food, Conservation, and Energy Act of 2008, see web site http://frwebgate.Access.gpo.gov/cgi-bin/getdoc.cgi?dbname=110_cong_public_laws&docid=f:publ246.110.pdf.
3. On December 23, 2008, after the November 2008 cut-off date for inclusion of changes in Federal and State laws and regulations in *AEO2009*, the United States Court of Appeals for the District of Columbia issued a new ruling that remanded but did not vacate CAIR, noting that "Allowing CAIR to remain in effect until it is replaced by a rule consistent with our opinion would at least temporarily preserve the environmental values." Source: United States Court of Appeals for the District of Columbia Circuit, No. 05-1244, web site www.epa.gov/airmarkets/progsregs/cair/docs/CAIRRemand Order.pdf. This change allows the EPA to modify CAIR to address the objections raised by the Court in its earlier decision while leaving the rule in place. The change is not reflected in *AEO2009*.
4. For complete text of the Emergency Economic Stabilization Act of 2008, including Division B, "Energy Improvement and Extension Act of 2008," see web site http://frwebgate.access.gpo.gov/cgi-bin/getdoc.cgi?dbname=110_cong_bills&docid=f:h1424enr.txt.pdf.
5. "Closed-loop" refers to fuels that are grown specifically for energy production, excluding wastes and residues from other activities, such as farming, landscaping, forestry, and woodworking.
6. Defense Energy Support Center, "Compilation of United States Fuel Taxes, Inspection Fees, and Environmental Taxes and Fees" (July 9, 2008).
7. U.S. Department of Transportation, National Highway Traffic Safety Administration, "Summary of Fuel Economy Performance," NHTSA-2007-28040-0001 (Washington, DC, March 2007), web site www.regulations.gov/fdmspublic/component/main?main=DocumentDetail&o=09000064802ad392.
8. U.S. Department of Transportation, National Highway Traffic Safety Administration, 49 CFR Parts 523, 531, 533, 534, 536, and 537 [Docket No. NHTSA-2008-0089] RIN 2127-AK29, *Notice of Proposed Rulemaking: Average Fuel Economy Standards Passenger Cars and Light Trucks Model Years 2011-2015* (Washington, DC, April 2008), pp. 14-15, web site www.nhtsa.dot.gov/portal/site/nhtsa/menuitem.43ac99aefa80569eea57529cdba046a0/.
9. A vehicle's footprint is defined as the wheelbase (the distance from the center of the front axle to the center of the rear axle) times the average track width (the distance between the center lines of the tires) of the vehicle in square feet.
10. U.S. Department of Transportation, National Highway Traffic Safety Administration, *Preliminary Regulatory Impact Analysis: Corporate Average Fuel Economy for MY 2011-2015 Passenger Cars and Light Trucks* (Washington, DC, April 2008), pp. 374-375, web site www.nhtsa.gov/staticfiles/DOT/NHTSA/Rulemaking/Rules/Associated%20Files/CAFE_2008_PRIA.pdf.
11. Most recently, the Consolidated Omnibus Appropriations Act of 2008 (Public Law 110-161, H.R. 2764) included the OCS moratorium as Sections 104, 105 and 412.
12. "OCS Lands Act History," web site www.mms.gov/aboutmms/OCSLA/ocslahistory.htm.
13. "OCS Lands Act History," web site www.mms.gov/aboutmms/OCSLA/ocslahistory.htm.
14. "Congressional Action to Help Manage Our Nation's Coasts," web site http://coastalmanagement.noaa.gov/czm/czm_act.html.
15. U.S. Department of the Interior, Minerals Management Service, "2001-Forward MRM Statistical Information: Reported Royalty Revenues," web site www.mrm.mms.gov/mrmwebstats/home.aspx.
16. See web site www.mms.gov/aboutmms/pdffiles/ocsla.pdf, p. 21, paragraph 1.
17. See web site www.mms.gov/ooc/newweb/publications/2003%20FACT.pdf, p. 7.
18. Energy Policy Act of 2005, Title III, Subtitle G, Section 384, "Coastal Impact Assistance Program," p. 147, web site www.epa.gov/oust/fedlaws/publ_109-058.pdf.
19. U.S. Department of the Interior, Minerals Management Service, *Report to Congress: Comprehensive Inventory of U.S. OCS Oil and Natural Gas Resources: Energy Policy Act of 2005—Section 357* (Washington, DC, February 2006), pp. v and vi, web site www.mms.gov/PDFs/2005EPAct/InventoryRTC.pdf.
20. For the complete text of the Energy Policy Act of 2005, see web site http://frwebgate.access.gpo.gov/cgi-bin/getdoc.cgi?dbname=109_cong_public_laws&docid=f:publ058.109.pdf.
21. See *AEO2008* for more detailed discussion of the program and the FY 2008 Appropriations Act.
22. At the same time, DOE also issued a solicitation for the front end of the nuclear fuel cycle. Because NEMS does not contain a direct representation of the front end of the nuclear fuel cycle, that solicitation is not considered in this analysis.
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24. U.S. Department of Energy, "DOE Announces Solicitation for $8.0 Billion in Loan Guarantees" (Washington, DC, September 22, 2008), web site www.lgprogram.energy.gov/press/092208.pdf.

25. A detailed discussion of the rationale for this assumption can be found in *AEO2008*. In brief, in 2007, DOE released technology-specific information about the requested guarantees from the 2006 solicitation. Included in that information were the requested dollar amounts of the guarantees, by technology. It was assumed, basically, that the dollar amounts of the approved guarantees would be proportional to the requested dollar amounts.
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27. United States Court of Appeals for the District of Columbia Circuit, No. 05-1097, web site http://pacer.cadc.uscourts.gov/docs/common/opinions/200802/05-1097a.pdf.
28. "The Clean Air Act [As Amended Through P.L. 108–201, February 24, 2004]," web site http://epw.senate.gov/envlaws/cleanair.pdf.
29. U.S. Environmental Protection Agency, "Clean Air Interstate Rule," web site www.epa.gov/airmarkets/progsregs/cair/.
30. United States Court of Appeals for the District of Columbia Circuit, No. 05-1244, web site http://pacer.cadc.uscourts.gov/docs/common/opinions/200807/05-1244-1127017.pdf.
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32. U.S. Environmental Protection Agency, web site www.epa.gov/airmarkets/progsregs/cair/docs/CAIR_Rehearing_Petition_as_Filed.pdf.
33. U.S. Environmental Protection Agency, web site www.epa.gov/airmarkets/progsregs/cair/docs/CAIR_Pet_Reply_Filed.pdf.
34. United States Court of Appeals for the District of Columbia Circuit, No. 05-1244, web site www.epa.gov/airmarkets/progsreg/cair/docs/CAIRRemandOrder.pdf.
35. The requirements for reformulated gasoline can be found in the 1990 Amendments to the Clean Air Act, Title II, Sec. 219 (web site www.epa.gov/oar/caa/caaa.txt). An excellent discussion of the history of oxygenate and other environmentally-based requirements for gasoline can be found in U.S. Environmental Protection Agency, *Fuel Trends Report: Gasoline 1995-2005*, EPA420-R-08-002 (Washington, DC, January 2008), web site www.epa.gov/otaq/regs/fuels/rfg/properf/420r08002.pdf.
36. Congressional Research Service, *Energy Independence and Security Act of 2007: A Summary of Major Provisions*, Order Code RL34294 (Washington, DC, December 2007), web site http://energy.senate.gov/public/_files/RL342941.pdf.
37. California Air Resources Board, "Low Carbon Fuel Standard Workshop: Review of the Draft Regulation" (October 16 2008), web site www.arb.ca.gov/fuels/lcfs/101608lcfsreg_prstn.pdf.
38. A feed-in-tariff guarantees a specified price, usually above the market level, on a long-term electricity purchasing agreement.
39. State of Michigan, 94th Legislature, Enrolled Senate Bill No. 213, web site www.legislature.mi.gov/documents/2007-2008/publicact/pdf/2008-PA-0295.pdf.
40. Although solar generation receives one bonus credit for each megawatthour produced, facilities using equipment manufactured in the same State and in-State workforces receive only 0.1 credit as a bonus.
41. Missouri Secretary of State, Amendment to Chapter 393 of the Revised Statutes of Missouri, Relating to Renewable Energy, web site www.sos.mo.gov/elections/2008petitions/2008-031.asp.
42. 127th General Assembly of the State of Ohio, Amended Substitute Senate Bill Number 221, web site www.legislature.state.oh.us/bills.cfm?ID=127_SB_0221.
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47. Regional Greenhouse Gas Initiative, "RGGI States' First CO_2 Auction Off to a Strong Start" (September 29, 2008), web site www.rggi.org/docs/rggi_press_9_29_2008.pdf.
48. Regional Greenhouse Gas Initiative, "Potential Emissions Leakage and the Regional Greenhouse Gas Initiative (RGGI)" (March 2008), web site http://rggi.org/docs/20080331leakage.pdf.
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Issues in Focus

Introduction

This section of the *AEO* provides discussions on selected topics of interest that may affect future projections, including significant changes in assumptions and recent developments in technologies for energy production, supply, and consumption. Issues discussed this year include trends in world oil prices and production; the economics of plug-in electric hybrids; the impact of reestablishing the moratoria on oil and natural gas drilling on the Federal OCS; expectations for oil shale production; the economics of bringing natural gas from Alaska's North Slope to U.S. markets; the relationship between natural gas and oil prices; the impacts of uncertainty about construction costs for power plants; and the impact of extending the renewable PTC for 10 years. Last, in view of growing concerns about GHG emissions, the topics discussed also include the impacts of such concerns on investment decisions and their handling in *AEO2009*.

The topics explored in this section represent current, emerging issues in energy markets; however, many of the topics discussed in *AEO*s published in recent years remain relevant today. Table 4 provides a list of titles from the 2008, 2007, and 2006 *AEO*s that are likely to be of interest to today's readers. They can be found on EIA's web site at www.eia.doe.gov/oiaf/aeo/otheranalysis/aeo_analyses.html.

World Oil Prices and Production Trends in *AEO2009*

The oil prices reported in *AEO2009* represent the price of light, low-sulfur crude oil in 2007 dollars [*50*]. Projections of future supply and demand are made for "liquids," a term used to refer to those liquids that after processing and refining can be used interchangeably with petroleum products. In *AEO2009*, liquids include conventional petroleum liquids—such as conventional crude oil and natural gas plant liquids—in addition to unconventional liquids, such as biofuels, bitumen, coal-to-liquids (CTL), gas-to-liquids (GTL), extra-heavy oils, and shale oil.

Developments in the world oil market over the course of 2008 exemplify how the level and expected path of world oil prices can change even over a period of days, weeks, or months. The difficulty for projecting prices into the future continues when the period of interest extends through 2030. Long-term world oil prices are determined by four fundamental factors: investment and production decisions by the Organization of the Petroleum Exporting Countries (OPEC); the economics of non-OPEC conventional liquids supply; the economics of unconventional liquids supply; and world demand for liquids. Uncertainty about long-term world oil prices can be considered in terms of developments related to one or more of these factors.

Recent Market Trends

The first 6 months of 2008 saw the continuation of the previous years' increases in oil prices, spurred by rising demand that was satisfied by relatively high-cost exploration and production projects, such as those in ultra-deep water and oil sands, at a time when shortages in everything from skilled labor to steel were driving up costs of even the most basic production projects. An apparent lack of demand

Table 4. Key analyses from "Issues in Focus" in recent AEOs

AEO2008	*AEO2007*	*AEO2006*
Impacts of Uncertainty in Energy Project Costs	*Impacts of Rising Construction and Equipment Costs on Energy Industries*	*Economic Effects of High Oil Prices*
Limited Electricity Generation Supply and Limited Natural Gas Supply Cases	*Energy Demand: Limits on the Response to Higher Energy Prices in the End-Use Sectors*	*Changing Trends in the Refining Industry*
Trends in Heating and Cooling Degree-Days: Implications for Energy Demand	*Miscellaneous Electricity Services in the Buildings Sector*	*Energy Technologies on the Horizon*
Liquefied Natural Gas: Global Challenges	*Industrial Sector Energy Demand: Revisions for Non-Energy-Intensive Manufacturing*	*Advanced Technologies for Light-Duty Vehicles*
World Oil Prices and Production Trends in AEO2008	*Impacts of Increased Access to Oil and Natural Gas Resources in the Lower 48 Federal Outer Continental Shelf*	*Nonconventional Liquid Fuels*
	Alaska Natural Gas Pipeline Developments	*Mercury Emissions Control Technologies*
	Coal Transportation Issues	*U.S. Greenhouse Gas Intensity and the Global Climate Change Initiative*

response to high prices in developing countries, China and India in particular, led to expectations of continuing high oil prices and the bidding up of prices for the inputs needed to increase supply, such as labor, drilling rigs, and other factors. Given the apparent lack of consumer response to price increases, lags in increasing supply, and the limited availability of light crude oils, some analysts believed that a price of $200 per barrel was plausible in the near term.

By July 2008, when world oil prices neared $150 per barrel, it had become apparent that petroleum consumption in the first half of the year was lower than anticipated, and that economic growth was slowing. August saw the beginning of the current global credit crisis and a further weakening of demand; and since September 2008, the global economic downturn has reduced consumers' current and prospective near-term demand for oil while at the same time the global credit crunch has restricted the ability of some suppliers to raise capital for projects to increase future production.

In the second half of 2008, producer and consumer expectations regarding the imbalance of supply and demand in the world oil market were essentially reversed. Before August, market expectations for the future economy indicated that demand would outpace supply despite planned increases in production capacity. After September, expectations became so dismal that OPEC's October 24 announcement of a 1.5-million-barrel-per-day production cut was followed by a drop in oil prices.

Although the impacts of the current economic downturn and credit crisis on petroleum demand are likely to be large in the near term, they also are likely to be relatively short-lived. National economies and oil demand are expected to begin recovering in 2010. In contrast, their impacts on oil production capacity probably will not be realized until the 2010-2013 period, when current new investments in capacity, had they been made, would have begun to result in more oil production. As a result, just at the time when demand is expected to recover, physical limits on production capacity could lead to another wave of price increases, in a cyclical pattern that is not new to the world oil market.

Long-Term Prospects

Developments in past months demonstrate how quickly and drastically the fundamentals of oil prices and the world liquids market as a whole can change. Within a matter of months, the change in current and prospective world liquids demand has affected the perceived need for additional access to conventional resources and development of unconventional liquids supply and reversed OPEC production decisions. The price paths assumed in *AEO2009* cover a broad range of possible future scenarios for liquids production and oil prices, with a difference of $150 per barrel (in real terms) between the high and low oil price cases in 2030. Although even that large difference by no means represents the full range of possible future oil prices, it does allow EIA to analyze a variety of scenarios for future conditions in the oil and energy markets in comparison with the reference case.

Reference Case

The *AEO2009* reference case is a "business as usual" trend case built on the assumption that, for the United States, existing laws, regulations, and practices will be maintained throughout the projection period. The reference case assumes that growth in the world economy and liquids demand will recover by 2010, with growth beginning in 2010 and continuing through 2013, when world demand for liquids surpasses the 2008 level. In the longer term, world economic growth is assumed to be roughly constant, and demand for liquids returns to a gradually increasing long-term trend. As the global recession fades, oil prices (in real 2007 dollars) begin rebounding, to $110 per barrel in 2015 and $130 per barrel in 2030.

Meeting the long-term growth of world liquids demand requires higher cost supplies, particularly from non-OPEC producers, as reflected in the reference case by a 1.1-percent average annual increase in the world oil price after 2015. Increases from OPEC producers will also be needed, but the organization is assumed to limit its production growth so that its share of total world liquids supply remains at approximately 40 percent.

The growth in non-OPEC production comes primarily from increasingly high-cost conventional production projects in areas with inconsistent fiscal or political regimes and from expensive unconventional liquids production projects. The return to historically high price levels would encourage the continuation of recent trends toward "resource nationalism," with foreign investors having less access to prospective areas, less attractive fiscal regimes, and higher exploration and production costs than in the first half of this decade.

Low Price Case

The *AEO2009* low price case assumes that oil prices remain at $50 per barrel between 2015 and 2030. The low price case assumes that free market competition and international cooperation will guide the development of political and fiscal regimes in both consuming and producing nations, facilitating coordination and cooperation between them. Non-OPEC producers are expected to develop fiscal policies and investment regulations that encourage private-sector participation in the development of their resources. OPEC is assumed to increase its production levels, providing 50 percent of the world's liquids in 2030. The availability of low-cost resources in both non-OPEC and OPEC countries allows prices to stabilize at relatively low levels, $50 per barrel in real 2007 dollars, and reduces the impetus for consuming nations to invest in the production of unconventional liquids as heavily as in the reference case.

High Price Case

The *AEO2009* high price case assumes not only that there will be a rebound in oil prices with the return of world economic growth but also that they will continue escalating rapidly as a result of long-term restrictions on conventional liquids production. The restrictions could arise from political decisions as well as resource limitations. Major producing countries, both OPEC and non-OPEC, could use quotas, fiscal regimes, and various degrees of nationalization to increase their national revenues from oil production. In that event, consuming countries probably would turn to high-cost unconventional liquids to meet some of their domestic demand. As a result, in the high price case, oil prices rise throughout the projection period, to a high of $200 per barrel in 2030. Demand for liquids is reduced by the high oil prices, but the demand reduction is overshadowed by severe limitations on access to, and availability of, conventional resources.

Components of Liquid Fuels Supply

In the reference case, total liquid fuels production in 2030 is about 20 million barrels per day higher than in 2007 (Table 5). Decisions by OPEC member countries about investments in new production capacity for conventional liquids, along with limitations on access to non-OPEC conventional resources, limit the increase in production to 11.3 million barrels per day, and their share of total global liquid fuels supply drops from 96 percent in 2007 to 88 percent in 2030.

Global production of unconventional petroleum liquids rises in the reference case. Production from Venezuela's Orinoco belt and Canada's oil sands increases but remains less than is economically viable because of access restrictions in Venezuela and environmental concerns in Canada. As a result, unconventional petroleum liquids production increases by only 3.6 million barrels per day, to 6 percent of global liquid fuels supply in 2030. Relatively high prices also encourage growth in production of CTL, GTL, biofuels, and other nonpetroleum unconventional liquids (which include stock withdrawals, blending components, other hydrocarbons, and ethers) from 1.7 million barrels per day in 2007 to 7.4 million barrels per day (7 percent of total liquids supplied) in 2030.

In the low price case, from 2015 to 2030, oil prices are on average almost 60 percent lower than in the reference case. As described above, a lower price path could be caused by increased access to resources in non-OPEC countries and decisions by OPEC member countries to expand their production. In the low price case, conventional crude oil production rises to 93.6 million barrels per day in 2030, the equivalent of

Table 5. Liquid fuels production in three cases, 2007 and 2030 (million barrels per day)

Projection	2007	2030		
		Reference	Low oil price	High oil price
Conventional liquids				
Conventional crude oil and lease condensate	71.0	77.3	93.6	57.7
Natural gas plant liquids	8.0	12.4	11.2	12.1
Refinery gain	2.1	2.7	3.2	2.1
Subtotal	**81.1**	**92.4**	**108.1**	**71.9**
Unconventional liquids				
Oil sands, extra-heavy crude oil, shale oil	2.0	5.6	6.7	6.1
Coal-to-liquids, gas-to-liquids	0.2	1.6	0.8	2.8
Biofuels	1.2	5.4	3.3	7.7
Other	0.3	0.4	0.4	0.4
Subtotal	**3.7**	**13.0**	**11.2**	**17.0**
Total	**84.8**	**105.4**	**119.3**	**88.9**

89 percent of total liquids production in 2030 in the reference case. Total conventional liquids production in the low price case rises above 100 million barrels per day in 2024 and continues upward to 108.1 million barrels per day in 2030.

Production of unconventional petroleum liquids is also higher in the low price case than in the reference case, despite their generally higher costs. The increase is based on assumed changes in access to resources. In the low price case, Venezuela's production of extra-heavy oil in 2030 increases to 3.0 million barrels per day, compared with 1.2 million barrels per day in the reference case—a 150-percent increase that more than compensates for a decrease of 0.5 million barrels per day in production from Canada's oil sands. As a result, total production of unconventional petroleum liquids in 2030 is 1.1 million barrels per day higher in the low price case than in the reference case. Production of CTL, GTL, biofuels, and other unconventional liquids in 2030 (primarily in the United States, China, and Brazil) is 2.9 million barrels per day lower than in the reference case, because the profitability of such projects is reduced.

In the high price case, from 2015 to 2030, oil prices average 56 percent more than in the reference case because of severe restrictions on access to non-OPEC conventional resources and reductions in OPEC production. Conventional liquids production in 2030 is 71.9 million barrels per day, down by 9.2 million barrels per day from 2007 production. Access limitations also constrain production of Venezuelan extra-heavy oil, which in 2030 totals 0.8 million barrels per day, or 0.4 million barrels per day less than in the reference case. Production of unconventional liquids from Canada's oil sands in 2030 is 0.9 million barrels per day higher than in the reference case, however, at 5.1 million barrels per day in 2030, which more than makes up for the decrease in production of extra-heavy oil.

Production of CTL, GTL, biofuels, and other unconventional liquids totals 3.5 million barrels per day more in 2030 in the high price case than in the reference case, primarily because China's CTL production in 2030 is approximately 0.8 million barrels per day more than in the reference case, and Brazil's biofuels production is 1.0 million barrels per day more than in the reference case. In the United States, GTL production starts in 2017 and increases to 0.4 million barrels per day in 2030 in the high oil price case.

Economics of Plug-In Hybrid Electric Vehicles

PHEVs have gained significant attention in recent years, as concerns about energy, environmental, and economic security—including rising gasoline prices—have prompted efforts to improve vehicle fuel economy and reduce petroleum consumption in the transportation sector. PHEVs are particularly well suited to meet these objectives, because they have the potential to reduce petroleum consumption both through fuel economy gains and by substituting electric power for gasoline use.

PHEVs differ from both conventional vehicles, which are powered exclusively by gasoline-powered internal combustion engines (ICEs), and battery-powered electric vehicles, which use only electric motors. PHEVs combine the characteristics of both systems.

Current PHEV designs use battery power at the start of a trip, to drive the vehicle for some distance until a minimum level of battery power is reached (the "minimum state of charge"). When the vehicle has reached its minimum state of charge, it operates on a mixture of battery and ICE power, similar to some hybrid electric vehicles (HEVs) currently in use. In charge-depleting operation, a PHEV is a fully functioning electric vehicle. Some HEVs also can operate in charge-depleting operation, but only for limited distances and at low speeds. Also, PHEVs can be engineered to run in a blended mode of operation, where an onboard computer determines the most efficient use of battery and ICE power.

PHEVs are unique in that their batteries can be recharged by plugging a power cord into an electrical outlet. The distance a PHEV can travel in all-electric (charge-depleting) mode is indicated by its designation. For example, a PHEV-10 is designed to travel about 10 miles on battery power alone before switching to charge-sustaining operation.

Although PHEV purchase decisions may be based in part on concerns about the environment or national energy security, or by a preference for the newest vehicle technology, a comprehensive evaluation of the potential for wide-scale penetration of PHEVs into the LDV transportation fleet requires, among other things, an analysis of economic costs and benefits for typical consumers. In general, consumers will be more willing to purchase PHEVs rather than conventional gasoline-powered vehicles if the economic benefits of doing so exceed the costs incurred. Therefore, an understanding of the economic benefits and costs of purchasing a PHEV is, in general, a fundamental factor in determining the potential for consumer acceptance that would allow PHEVs to compete seriously in LDV markets.

The major economic benefit of purchasing a PHEV is its significant fuel efficiency advantage over a conventional vehicle (Table 6). The PHEV can use rechargeable battery power over its all-electric range before entering charge-sustaining mode, and its all-electric operation is more energy-efficient than either a conventional ICE vehicle or the hybrid mode of an HEV (or the hybrid operation of the PHEV itself).

On a gasoline-equivalent basis (with electricity efficiency estimated "from the plug") a PHEV's charge-depleting battery system gets on average about 105 mpg, well above even the most efficient petroleum-based ICE. When the PHEV enters charge-sustaining mode, it also takes advantage of its hybrid ICE-battery operation to achieve a relatively efficient 42 mpg. As a result, the total annual fuel expenditures for a PHEV, combining both electricity costs and gasoline, are lower than those of a conventional ICE vehicle using gasoline. The fuel savings are amplified when the PHEV's all-electric range is increased, when gasoline prices are high, or when the difference between gasoline prices and electricity prices increases (Figure 7).

Although the lower fuel costs of PHEVs provide an obvious economic benefit, currently they are significantly more expensive to buy than a comparable conventional vehicle. The price difference results from the costs of the PHEV's battery pack and the hybrid system components that manage the use and storage of electricity. The incremental cost of the battery pack depends on its storage capacity, power output, and chemistry. For example, the electricity storage requirements for a PHEV-40, designed to travel about 40 miles on battery power alone before switching to charge-sustaining operation, are considerably larger than those for a PHEV-10. In terms of power output, PHEV batteries will be engineered to meet the typical performance needs of LDVs, such as acceleration.

Currently two competing chemistries are seen as viable options for PHEV batteries—nickel metal hydride (NiMH) and lithium-ion (Li-Ion)—with different strengths and weaknesses. NiMH batteries are cheaper to produce per kilowatthour of capacity and have a proven safety record; however, their relative weight may limit their use in PHEVs. Li-Ion batteries have the potential to store significantly more electricity in lighter batteries; however, their use in PHEVs currently is limited by concerns about their calendar life, cycle life, and safety. Different vehicle manufacturers have reached different conclusions about which battery chemistry they will use in their initial PHEV offerings, but the majority consensus is that Li-Ion batteries have the most promise for the long term [*51*], and in this analysis they are assumed to be the battery of choice.

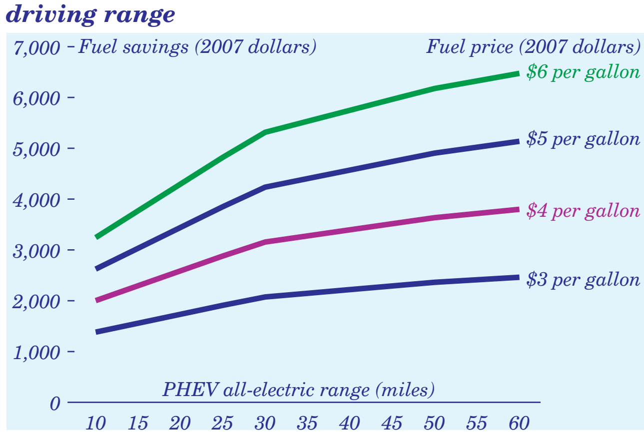
The second cost element associated with PHEVs is the cost of the additional electronic components and hardware required to manage vehicle electrical systems and provide electrical motive power. The

Table 6. Assumptions used in comparing conventional and plug-in hybrid electric vehicles

Characteristics	*Conventional ICE[a]*	*PHEV[b]*
Fuel efficiency (miles per gallon of gasoline equivalent)	*35*	*105 (charge-depleting mode) 42 (charge-sustaining mode)*
Discount rate	*10 percent*	*10 percent*
Discount period	*6 years*	*6 years*
Annual vehicle-miles traveled	*14,000*	*14,000*
Electricity price per kilowatthour	*—*	*$0.10*

[a]Light-duty vehicle with gasoline-powered internal combustion engine.
[b]Light-duty vehicle with lithium-ion battery for charge-depleting mode and hybrid gasoline-powered internal combustion and battery engine for charge-sustaining mode.

Figure 7. Value of fuel saved by a PHEV compared with a conventional ICE vehicle over the life of the vehicles, by gasoline price and PHEV all-electric driving range



conventional vehicle systems on a PHEV may be less costly than those on conventional gasoline vehicles, because the PHEV's engine and (if required) transmission are smaller, but the saving is negated by the additional costs associated with the electric motor, power inverter, wiring, charging components, thermal packaging to prevent battery overheating, and other parts.

An example of the differences in various vehicle system costs (excluding the battery pack) between a PHEV-20, designed to travel about 20 miles on battery power alone before switching to charge-sustaining operation, and a similar conventional vehicle is shown in Table 7 [*52*]. The estimated incremental cost of the PHEV-20 shown in the table represents the combined incremental costs of all vehicle systems other than the battery, at production volumes expected in 2020 or 2030.

The combined costs of the PHEV battery and battery supporting systems together represent the total incremental costs of a PHEV compared to a conventional gasoline vehicle. In the long run, however, the costs of PHEV battery and vehicle systems are not expected to remain static. Successes in research and development are expected to improve battery characteristics and reduce costs over time. In addition, as more Li-Ion batteries and system components are produced, manufacturers are expected to improve production techniques and decrease costs through economies of scale (Figure 8).

Table 7. Conventional vehicle and plug-in electric hybrid system component costs for mid-size vehicles at volume production (2007 dollars)

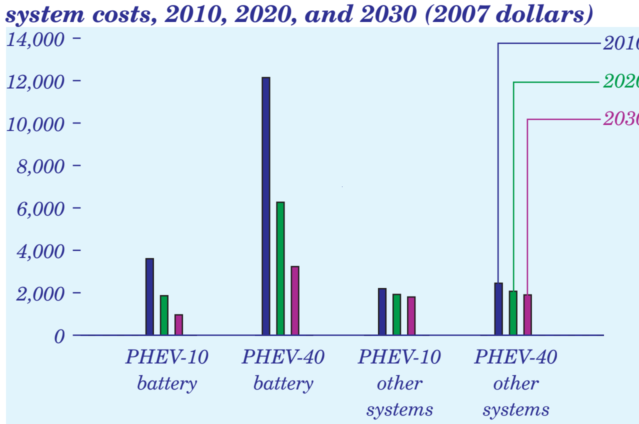
Vehicle component	Conventional ICE	PHEV-20
Engine/exhaust	2,357	1,370
Transmission	1,045	625
Accessory power	210	300
Electric traction	40	1,542
Starter motor	40	—
Electric motor	—	893
Power inverter	—	528
Electronics thermal	—	121
On-vehicle charging system	—	460
Other battery/storage costs	30	809
Fuel storage (tank)	10	10
Accessory battery	20	15
Pack tray	—	170
Pack hardware	—	500
Battery thermal	—	114
Total	**3,682**	**5,106**
PHEV incremental cost	**—**	**1,424**

To incentivize purchases of initial PHEV offerings, the recently passed EIEA2008 grants a tax credit of $2,500 for PHEVs with at least 4 kilowatthours of battery capacity (about the size of a PHEV-10 battery), with larger batteries earning an additional $417 per kilowatthour up to a maximum of $7,500 for light-duty PHEVs, which would be reached at a battery size typical for a PHEV-40 [*53*]. The credit will apply until 250,000 eligible PHEVs are sold or until 2015, whichever comes first.

ARRA2009, which was enacted in February 2009, modifies the PHEV tax credit so that the minimum battery size earning additional credits is 5 kilowatthours and the maximum allowable credit based on battery size remains unchanged at $5,000. ARRA-2009 also extends the number of eligible vehicles from a cumulative total of 250,000 for all manufacturers to more than 200,000 vehicles per manufacturer, with no expiration date on eligibility. After a manufacturer's cumulative production of eligible PHEVs reaches 200,000 vehicles, the tax credits are reduced by 50 percent for the preceding 2 quarters and to 25 percent of the initial value for the preceding third and fourth quarters. ARRA2009 is not considered in *AEO2009*.

As a result of the EIEA2008 tax credit, the combined cost of a PHEV battery and PHEV system in 2010 will be lower than it would be without the credit. Moreover, even after the credit has expired, incentivizing the purchase of PHEVs in the near term will allow both battery and battery-system manufacturers to achieve earlier economies of scale through greater initial sales, thus allowing battery and systems costs to decline more quickly than would have been the case without the tax credit. As a result, the combined incremental costs for PHEVs are expected to be

Figure 8. PHEV-10 and PHEV-40 battery and other system costs, 2010, 2020, and 2030 (2007 dollars)



significantly lower in 2030, when economies of scale and learning have been fully realized (Figure 9).

A typical consumer may be willing to purchase a PHEV instead of a conventional ICE vehicle when the economic benefit of reduced fuel expenditures is greater than the total incremental cost of the PHEV. On that basis, PHEVs face a significant challenge. Even in 2030, the additional cost of a PHEV is projected to be higher than total fuel savings unless gasoline prices are around $6 per gallon (Figure 10). In the meantime, the cost challenge for PHEVs is even greater (Figure 11), which leads to an important problem: if consumers do not choose to buy PHEVs because they are not cost-competitive with conventional vehicles in the near term, then PHEV sales volumes will not be sufficient to induce the economies of scale assumed for this analysis.

In addition to the economic challenge, PHEVs also face uncertainty with respect to Li-Ion battery life and safety [*54*]. Further, they will continue to face competition from other vehicle technologies, including diesels, grid-independent gasoline-electric hybrids, FFVs, and more efficient conventional gasoline vehicles, all of which are likely to become more fuel-efficient in the next 20 years.

Future advances in Li-Ion battery technology could address economic, lifetime, and safety concerns, paving the way for large-scale sales and significant penetration of PHEVs into the U.S. LDV fleet. For example, a technological breakthrough could conceivably allow for smaller batteries with the same capacity and power output, thus lowering incremental costs and making PHEVs attractive on a cost-benefit basis. Also, there are at least two non-economic arguments in favor of PHEVs. First, PHEVs could significantly reduce GHG emissions in the transportation

Figure 9. Incremental cost of PHEV purchase with EIEA2008 tax credit included compared with conventional ICE vehicle purchase, by PHEV all-electric driving range, 2010, 2020, and 2030 (2007 dollars)

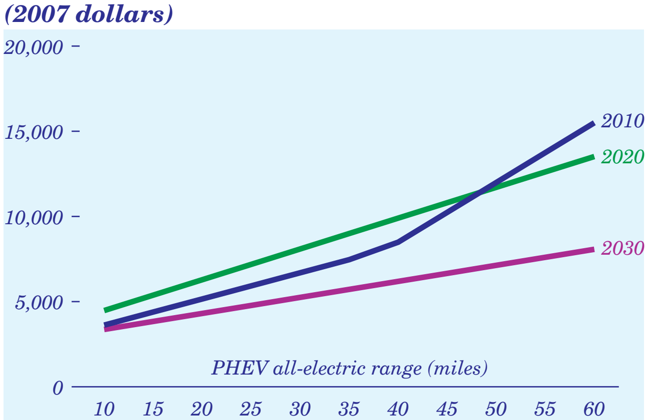


Figure 10. PHEV fuel savings and incremental vehicle cost by gasoline price and PHEV all-electric driving range, 2030 (2007 dollars)

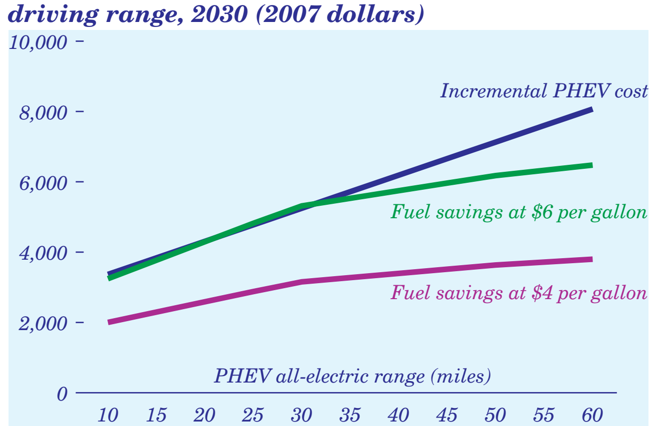


Figure 11. PHEV fuel savings and incremental vehicle cost by gasoline price and PHEV all-electric driving range, 2010 and 2020 (2007 dollars)

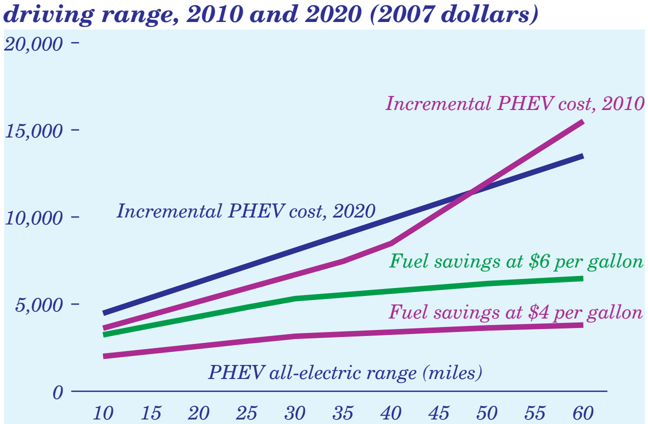
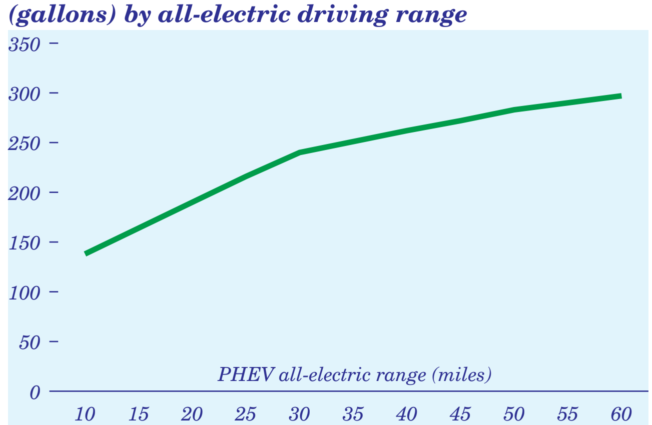


Figure 12. PHEV annual fuel savings per vehicle (gallons) by all-electric driving range



sector, depending on the fuels used to produce electricity. Second, PHEVs use less gasoline than conventional ICE vehicles (Figure 12). If PHEVs displaced conventional ICE vehicles, U.S. petroleum imports could be reduced [*55*].

Impact of Limitations on Access to Oil and Natural Gas Resources in the Federal Outer Continental Shelf

The U.S. offshore is estimated to contain substantial resources of both crude oil and natural gas, but until recently some of the areas of the lower 48 OCS have been under leasing moratoria [*56*]. The Presidential ban on offshore drilling in portions of the lower 48 OCS was lifted in July 2008, and the Congressional ban was allowed to expire in September 2008, removing regulatory obstacles to development of the Atlantic and Pacific OCS [*57*, *58*].

Although the Atlantic and Pacific lower 48 OCS regions are open for exploration and development in the *AEO2009* reference case, timing issues constrain the near-term impacts of increased access. The U.S. Department of Interior, MMS, is in the process of developing a leasing program that includes selected tracts in those areas, with the first leases to be offered in 2010 [*59*]; however, there is uncertainty about the future of OCS development. Environmentalists are calling for a reinstatement of the moratoria. Others cite the benefits of drilling in the offshore. Recently, the U.S. Department of the Interior extended the period for comment on oil and natural gas development on the OCS by 180 days and established other processes to allow more careful evaluation of potential OCS development.

Assuming that leasing actually goes forward on the schedule contemplated by the previous Administration, the leases must then be bid on and awarded, and the wining bidders must develop exploration and development plans and have them approved before any wells can be drilled. Thus, conversion of the newly available OCS resources to production will require considerable time, in addition to financial investment. Further, because the expected average field size in the Pacific and Atlantic OCS is smaller than the average field size in the Gulf of Mexico, a portion of the additional OCS resources may not be as economically attractive as available resources in the Gulf.

Estimates from the MMS of undiscovered resources in the OCS are the starting point for EIA's estimate of the OCS technically recoverable resource. Adding the mean MMS estimate of undiscovered technically recoverable resources to proved reserves and inferred resources in known deposits, the remaining technically recoverable resource (as of January 1, 2007) in the OCS is estimated to be 93 billion barrels of crude oil and 456 trillion cubic feet of natural gas (Table 8). The OCS areas that were until recently under moratoria in the Atlantic, Pacific, and Eastern/Central Gulf of Mexico are estimated to hold roughly 20 percent (18 billion barrels) of the total OCS technically recoverable oil—10 billion barrels in the Pacific and nearly 4 billion barrels each in the Eastern/Central Gulf of Mexico and Atlantic OCS. Roughly 76 trillion cubic feet of natural gas (or 17 percent) is estimated to be in areas formerly under moratoria, with nearly 37 trillion cubic feet in the Atlantic, 18 trillion cubic feet in the Pacific, and 21 trillion cubic feet in the Eastern/Central Gulf of Mexico. It should be noted that there is a greater degree of uncertainty about resource estimates for most of the OCS acreage previously under moratoria, owing to the absence of previous exploration and development activity and modern seismic survey data.

To examine the potential impacts of reinstating the moratoria, an OCS limited case was developed for

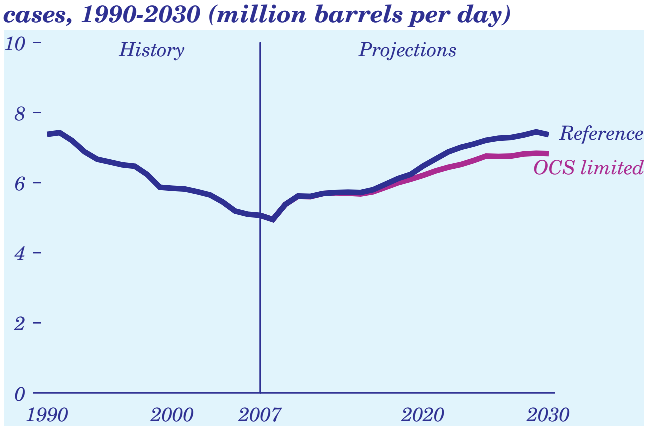
Table 8. Technically recoverable resources of crude oil and natural gas in the Outer Continental Shelf, as of January 1, 2007

Resource area and category	*Crude oil (billion barrels)*	*Natural gas (trillion cubic feet)*
Undiscovered resources		
Gulf of Mexico	*34.29*	*183.21*
Eastern and Central Gulf of Mexico (earliest leasing in 2022)	*3.65*	*21.46*
Pacific (earliest leasing in 2010)	*10.50*	*18.43*
Atlantic (earliest leasing in 2010)	*3.92*	*36.50*
Alaska	*26.61*	*132.06*
Total undiscovered	***78.97***	***391.66***
Proved reserves		
Gulf of Mexico	*3.66*	*14.55*
Pacific	*0.44*	*0.81*
Atlantic	*0.00*	*0.00*
Alaska	*0.03*	*0.00*
Total proved reserves	***4.13***	***15.36***
Inferred reserves		
Gulf of Mexico	*9.33*	*48.83*
Pacific	*0.89*	*0.26*
Atlantic	*0.00*	*0.00*
Alaska	*0.00*	*0.00*
Total inferred reserves	***10.21***	***49.09***
Total OCS resources	***93.31***	***456.11***

AEO2009. It is based on the *AEO2009* reference case but assumes that access to the Atlantic, Pacific, and Eastern/Central Gulf of Mexico OCS will be limited again by reinstatement of the moratoria as they existed before July 2008. In the OCS limited case, technically recoverable resources in the OCS total 75 billion barrels of oil and 380 trillion cubic feet of natural gas.

The projections in the OCS limited case indicate that reinstatement of the moratoria would decrease domestic production of both oil and natural gas and increase their prices (Table 9). The impact on domestic crude oil production starts just before 2020 and increases through 2030. Cumulatively, domestic crude oil production from 2010 to 2030 is 4.2 percent lower in the OCS limited case than in the reference case. In 2030, lower 48 offshore crude oil production in the OCS limited case (2.2 million barrels per day) is 20.6 percent lower than in the reference case (2.7 million barrels per day), and total domestic crude oil production, at 6.8 million barrels per day, is 7.4 percent lower than in the reference case (Figure 13).

Figure 13. U.S. total domestic oil production in two cases, 1990-2030 (million barrels per day)



In 2007, domestic crude oil production totaled 5.1 million barrels per day.

With limited access to the lower 48 OCS, U.S. dependence on imports increases, and there is a small increase in world oil prices. Oil import dependence in 2030 is 43.4 percent in the OCS limited case, as compared with 40.9 percent in the reference case, and the total annual cost of imported liquid fuels in 2030 is $403.4 billion, 7.1 percent higher than the projection of $376.6 billion in the reference case. The average price of imported low-sulfur crude oil in 2030 (in 2007 dollars) is $1.34 per barrel higher, and the average U.S. price of motor gasoline price is 3 cents per gallon higher, than in the reference case.

As with liquid fuels, the impact of limited access to the OCS on the domestic market for natural gas is seen mainly in the later years of the projection. Cumulative domestic production of dry natural gas from 2010 through 2030 is 1.3 percent lower in the OCS limited case than in the reference case. Because the volume of technically recoverable natural gas in the OCS areas previously under moratoria accounts for less than 5 percent of the total U.S. technically recoverable natural gas resource base, the impacts for natural gas volumes are smaller, relative to the baseline supply level, than those for oil volumes.

In 2030, dry natural gas production from the lower 48 offshore totals 4.1 trillion cubic feet in the OCS limited case, as compared with 4.9 trillion cubic feet in the reference case. The reduction in offshore supply of natural gas in the OCS limited case is partially offset, however, by an increase in onshore production. Reduced access in the OCS limited case results in higher natural gas prices, which increase the projection for U.S. onshore production in 2030 by 0.2 trillion cubic feet over the reference case projection. The

Table 9. Crude oil and natural gas production and prices in two cases, 2020 and 2030

Projection	Crude oil production (million barrels per day)	Crude oil price (2007 dollars per barrel)	Motor gasoline price (2007 dollars per gallon)	Natural gas production (trillion cubic feet)	Natural gas price (2007 dollars per thousand cubic feet)
2020					
Reference case	6.48	115.45	3.60	21.48	6.75
OCS limited case	6.21	115.56	3.60	21.27	6.83
Difference from reference case	-0.27	0.10	0.00	-0.21	0.08
Percent difference from reference case	-4.2	0.1	0.0	-0.7	1.2
2030					
Reference case	7.37	130.43	3.88	23.60	8.40
OCS limited case	6.83	131.76	3.91	23.00	8.61
Difference from reference case	-0.54	1.34	0.03	-0.60	0.21
Percent difference from reference case	-7.4	1.0	0.8	-2.6	2.5

average U.S. wellhead price of natural gas in 2030 (per thousand cubic feet, in 2007 dollars) is 21 cents higher in the OCS limited case, and net imports increase by 240 billion cubic feet. The higher average wellhead price for natural gas from the lower 48 States in the OCS limited case is associated with a decrease in consumption of 360 billion cubic feet in 2030 relative to the reference case. Total U.S. production of dry natural gas is 210 billion cubic feet less in 2020 and 600 billion cubic feet less in 2030 in the OCS limited case than projected in the reference case (Figure 14).

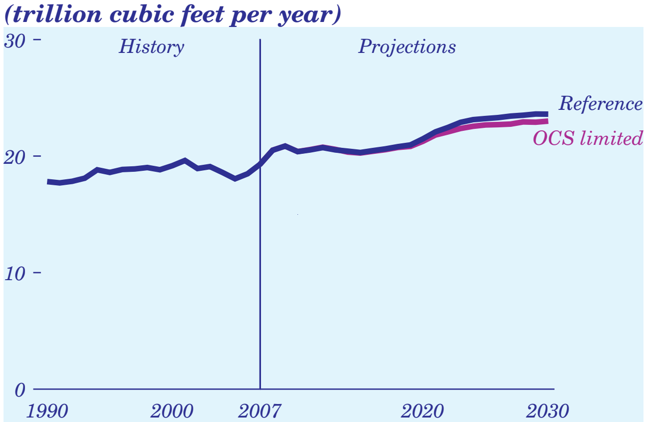
Offshore production, particularly in the OCS, has been an important source of domestic crude oil and natural gas supply, and it continues to be a key source of domestic supply throughout the projections either with or without the restoration of leasing moratoria as they existed before 2008.

Expectations for Oil Shale Production

Background

Oil shales are fine-grained sedimentary rocks that contain relatively large amounts of kerogen, which can be converted into liquid and gaseous hydrocarbons (petroleum liquids, natural gas liquids, and methane) by heating the rock, usually in the absence of oxygen, to 650 to 700 degrees Fahrenheit (*in situ* retorting) or 900 to 950 degrees Fahrenheit (surface retorting) [*60*]. (“Oil shale” is, strictly speaking, a misnomer in that the rock is not necessarily a shale and contains no crude oil.) The richest U.S. oil shale deposits are located in Northwest Colorado, Northeast Utah, and Southwest Wyoming (Table 10). Currently, those deposits are the focus of petroleum industry research and potential future production.

Figure 14. U.S. total domestic dry natural gas production in two cases, 1990-2030 (trillion cubic feet per year)



Among the three States, the richest oil shale deposits are on Federal lands in Northwest Colorado.

The Colorado deposits start about 1,000 feet under the surface and extend down for as much as another 2,000 feet. Within the oil shale column are rock formations that vary considerably in kerogen content and oil concentration. The entire column ultimately could produce more than 1 million barrels oil equivalent per acre over its productive life. To put that number in context, Canada’s Alberta oil sands deposits are expected to produce about 100,000 barrels per acre.

The recoverable oil shale resource base is characterized by oil yield per ton of rock, based on the Fischer assay method [*61*]. Table 10 summarizes the approximate recoverable oil shale resource within the three States, based on the relative oil concentration in the oil shale rock. In addition to oil, the estimates include natural gas and natural gas liquids, which make up 15 to 40 percent of the total recoverable energy, depending upon the specific shale rock characteristics and the process used to extract the oil and natural gas. The three States contain about 800 billion barrels of recoverable oil in deposits with expected yields of more than 20 to 25 gallons oil equivalent per ton, which are more attractive economically than deposits with lower concentrations of oil. In comparison, on December 31, 2007, U.S. crude oil reserves were 21 billion barrels, or roughly 2.5 percent of the amount potentially recoverable from oil shale deposits in the three States [*62*].

Oil Shale Production Techniques

Liquids and gases can be produced from oil shale rock by either *in situ* or surface retorting. During the mid-1970s and early 1980s, the petroleum industry focused its efforts primarily on underground mining and surface retorting, which consumes large volumes of water, creates large waste piles of spent shale, and extracts only the richest portion of the oil shale

Table 10. Estimated recoverable resources from oil shale in Colorado, Utah, and Wyoming

Oil concentration (gallons oil equivalent per ton of rock)	Recoverable oil resource (billion barrels oil equivalent)
>10	1,500
>15	1,200
>20	850
>25	750
>30	420
>40	250

formation. There were also some experiments using a "modified *in situ* process," in which rock was mined from the base of the oil shale formation, explosive charges were set in the mined-out area (causing the roof to collapse and fragmenting the rock into smaller masses), and underground fires were set on the rubble to extract natural gas and petroleum liquids. The combustion proved difficult to control, however, and the process produced only low yields of petroleum liquids. Surface subsidence and aquifer contamination were additional issues.

The *in situ* processes now under development raise the temperature of shale formations by using electrical resistance or radio wave heating in wells that are separate from the production wells. Also being considered are "ice walls"—commonly used in construction—both to keep water out of the areas being heated and to keep the petroleum liquids that are produced from contaminating aquifers. The benefits of those methods include uniform heating of the formation; high yields of gas and liquid per ton of rock; production of high-quality liquids that commingle naphtha, distillates, and fuel oil and can be upgraded readily to marketable products; production yields of more than 1 million barrels per acre in some locations; no requirement for disposal and remediation of waste rock; reduced water requirements; scalability, so that additional production can be added readily to an existing project at production costs equal to or less than the cost of the original project; and lower overall production costs. Given these advantages, an *in situ* process is likely to be used if large-scale production of oil shale is initiated.

Although the technical feasibility of *in situ* retorting has been proved, considerable technological development and testing are needed before any commitment can be made to a large-scale commercial project. EIA estimates that the earliest date for initiating construction of a commercial project is 2017. Thus, with the leasing, planning, permitting, and construction of an *in situ* oil shale facility likely to require some 5 years, 2023 probably is the earliest initial date for first commercial production.

Economic Issues

Because no commercial *in situ* oil shale project has ever been built and operated, the cost of producing oil and natural gas with the technique is highly uncertain. Current estimates of future production costs range from at least $70 to more than $100 per barrel oil equivalent in 2007 dollars. Therefore, future oil shale production will depend on the rate of technological progress and on the levels and volatility of future oil prices.

Technology progress rates will determine how quickly the costs of *in situ* oil shale extraction can be brought down and how quickly natural gas and petroleum liquids can be produced from the process. The *in situ* retorting techniques currently available require the production zone to be heated for 18 to 24 months before full-scale production can begin.

In addition to price levels, the volatility of oil prices is particularly important for a high-cost, capital-intensive project like oil shale production, because price volatility increases the risk that costs will not be recovered over a reasonable period of time. For example, if oil prices are unusually low when production from an oil shale project begins, the project might never see a positive rate of return.

Public Policy Issues

Development of U.S. oil shale resources also faces a number of public policy issues, including access to Federal lands, regulation of CO_2 emissions, water usage and wastewater disposal, and the disturbance and remediation of surface lands. If the petroleum industry were not permitted access to Federal lands in the West, especially in Northwest Colorado, the industry would be excluded from the largest and most economical portion of the U.S. oil shale resource base.

In addition, current regulations of the U.S. Bureau of Land Management require that any mineral production activity on leased Federal lands also produce any secondary minerals found in the same deposit. On Federal oil shale lands, deposits of nahcolite (a naturally occurring form of sodium bicarbonate, or baking soda) are intermixed with the oil shales. Relative to oil and other petroleum products, nahcolite is a low-value commodity, and its price would fall even further if its production increased significantly. Thus, co-production of nahcolite could increase the cost of producing oil shale significantly, while providing little revenue in return.

Bringing Alaska North Slope Natural Gas to Market

At least three alternatives have been proposed over the years for bringing sizable volumes of natural gas from Alaska's remote North Slope to market in the lower 48 States: a pipeline interconnecting with the existing pipeline system in central Alberta, Canada;

a GTL plant on the North Slope; and a large LNG export facility at Valdez, Alaska. NEMS explicitly models the pipeline and GTL options [*63*]. The "what if" LNG option is not modeled in NEMS.

This comparison analyzes the economics of the three project options, based on the oil and natural gas price projections in the *AEO2009* reference, high oil price, and low oil price cases. The most important factors in the comparison include expected construction lead times, capital costs, and operating costs. Others include lower 48 natural gas prices, world crude oil and petroleum product prices, interest rates, and Federal and State regulation of leasing, royalty, and production tax rates. Each option also presents unique technological challenges.

Natural Gas Resources and Production Costs

Natural gas exists either in oil reservoirs as associated-dissolved (AD) natural gas or in gas-only reservoirs as nonassociated (NA) natural gas. Of the 35.4 trillion cubic feet of AD gas reserves discovered on the Central North Slope in conjunction with existing oil fields, 93 percent is located in four fields: Prudhoe Bay (23 trillion cubic feet), Point Thomson (8 trillion cubic feet), Lisburne (1 trillion cubic feet), and Kuparak (1 trillion cubic feet) [*64*]. Together, those resources are sufficient to provide 4 billion cubic feet of natural gas per day for a period of 24 years, at an expected average cost of $1.12 per thousand cubic feet (2007 dollars) [*65*]. The cost estimate is relatively low, because an extensive North Slope infrastructure has been built and paid for with revenues from oil production, and because there is considerably less exploration, development, and production risk associated with known deposits of AD natural gas.

Although additional AD natural gas might be discovered offshore or in the Arctic National Wildlife Refuge, most of the "second tier" discoveries in areas to the west and south of the Central North Slope are expected to consist of NA natural gas in gas-only reservoirs. Production costs for gas-only reservoirs are expected to be considerably higher than those for AD natural gas, because they are in remote locations. In addition, the full costs of their development will have to be paid for with revenues from the natural gas generated at the wellhead.

For the first tier of North Slope NA natural gas (29.2 trillion cubic feet) production costs are expected to average $7.91 per thousand cubic feet (2007 dollars). For the second tier, production costs are expected to average $11.03 per thousand cubic feet. Because the cost of producing NA natural gas is substantially greater than the cost of producing AD natural gas, this analysis uses the lower production costs for AD natural gas to evaluate the economic merits of the three facility options examined.

Facility Cost Assumptions

Of the three facility options, the costs associated with an Alaska gas pipeline are reasonably well defined, because they are based on the November 2007 pipeline proposals submitted to the State of Alaska by ConocoPhillips and TransCanada Pipelines, in compliance with the requirements of the Alaska Gasline Inducement Act. Costs associated with GTL and LNG facilities are more speculative, because they are based on the costs of similar facilities elsewhere in the world, adjusted for the remote Alaska location and for recent worldwide increases in construction costs (Table 11).

Key assumptions for all the options analyzed include natural gas feedstock requirements of 4 billion cubic feet per day, natural gas heating values, characteristics of the operations, and State and Federal income tax rates. The time required for planning, obtaining required permits, and facility construction is unique to each facility. Other key assumptions that are unique to each option include the following: for the Alaska pipeline option, the tariff rate for the existing pipeline from Alberta to Chicago and the spot price for natural gas in Chicago; for the LNG facility option, capital and operating costs, including the cost of building a pipeline from the North Slope to liquefaction and storage facilities in Valdez, and the value of LNG delivered in Asia and Valdez (which is contractually tied to oil prices); and for the GTL facility option, the time required to conduct tests to determine whether the Trans Alaska Pipeline System (TAPS) should be operated in batch or commingled mode with GTL, the production level and mix of product, the oil pipeline tariff and tanker rates to U.S.

Table 11. Assumptions for comparison of three Alaska North Slope natural gas facility options

Assumption	Pipeline option	LNG option	GTL option
Natural gas conversion efficiency (percent)	*94*	*80*	*60*
Capital costs (billion 2007 dollars)	*27.6*	*33.9*	*57.5*
Operating costs (million 2007dollars per year)	*263.0*	*392.9*	*894.3*

West Coast refiners, and the price of GTL products relative crude oil prices. The costs of testing and possibly converting TAPS into a batching crude/product pipeline are not included for the GTL option.

Discussion

To compare the economics of the three options, an internal rate of return (IRR) was calculated for each alternative, based on the projected average price of light, low-sulfur crude oil and the projected average price of natural gas on the Henry Hub spot market in the *AEO2009* reference, high oil price, and low oil price cases for the 2011-2020 and 2021-2030 periods (Table 12). The IRR calculations (Figures 15 and 16) assume that the average prices for the period in which a facility begins operation will persist throughout the 20-year economic life of the facility. Projected crude oil prices show considerably more variation across the cases and time periods than do Henry Hub natural gas prices, affecting the relative economics of the three options. In 2030, in the low and high oil price cases, crude oil prices are $50 and $200 per barrel, respectively, and lower 48 natural gas prices are $8.70 and $9.62 per million Btu, respectively (all prices in 2007 dollars).

Table 12. Average crude oil and natural gas prices in three cases, 2011-2020 and 2021-2030

	2011-2020	2021-2030
Oil price (2007 dollars per barrel)		
Reference	107.32	123.26
High oil price	154.24	193.25
Low oil price	51.61	50.31
Natural gas price (2007 dollars per million Btu)		
Reference	7.04	8.21
High oil price	7.52	8.50
Low oil price	6.24	7.88

The *AEO2009* projections show wide variations in oil prices, which are set outside the NEMS framework to reflect a range of potential future price paths. For natural gas prices, variations across the cases are smaller, reflecting the feedbacks in NEMS that equilibrate supply, demand, and prices in the natural gas market model. Natural gas price increases are held in check by declines in demand (especially in the electric power sector) and increases in natural gas drilling, reserves, and production capacity. Conversely, natural gas price declines are held in check by increases in demand and decreases in drilling, reserves, and production capacity. Natural gas prices are also restrained because only a small portion of the natural gas resource base is consumed through 2030, and the marginal cost of natural gas supply increases slowly.

IRRs for the pipeline option respond to natural gas price levels, whereas IRRs for the GTL and LNG options respond to crude oil prices (Figures 15 and 16). From 2021 through 2030, IRRs for the pipeline option vary by 15 to 17 percent across the three price cases, whereas those for the GTL and LNG options vary by 4 to 24 percent and 7 to 27 percent, respectively. On that basis, the pipeline option would be considerably less risky than either the GTL or LNG option. Also, the pipeline would involve significantly less engineering, construction, and operation risk than either of the other options.

The potential viability of an Alaska natural gas pipeline is bolstered by the fact that BP, ConocoPhillips, and TransCanada Pipelines already have committed to building a pipeline. All three have extensive

Figure 15. Average internal rates of return for three Alaska North Slope natural gas facility options in three cases, 2011-2020 (percent)

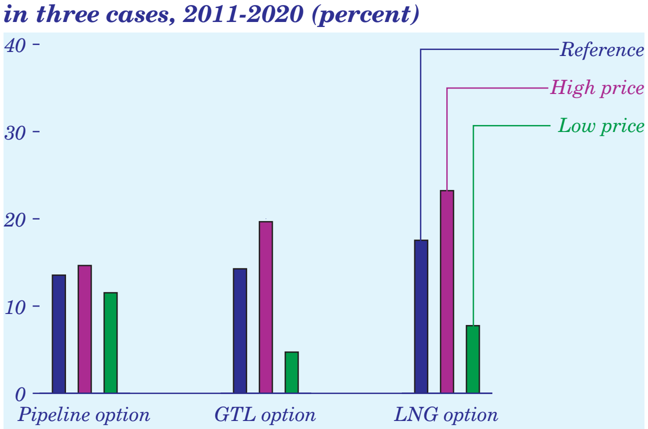
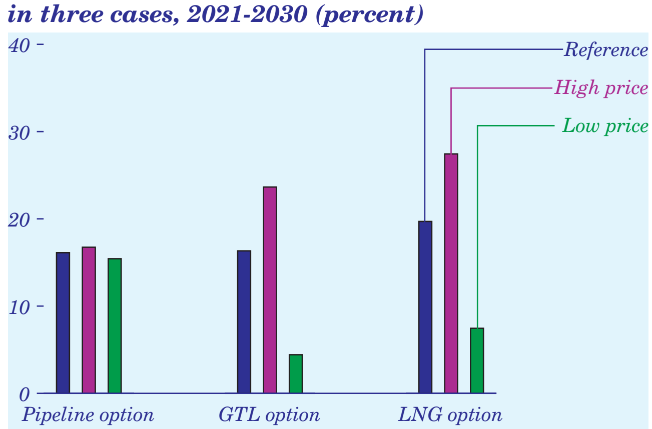


Figure 16. Average internal rates of return for three Alaska North Slope natural gas facility options in three cases, 2021-2030 (percent)



experience in building and financing large-scale energy projects, and both BP and ConocoPhillips have access to substantial portions of the less expensive North Slope AD natural gas reserves. Given that institutional support, along with the prospect for adequate rates of return, the natural gas pipeline option appears to have the greatest likelihood of being built.

Because the GTL option does not include the cost of testing and adapting the existing TAPS oil pipeline to GTL products—which would require third-party cooperation and likely cost reimbursement—the GTL rates of return are overstated. In addition, the GTL results include considerable uncertainty with regard to capital and operating costs and future environmental constraints on GTL plants. Prospects for Alaska GTL facilities are further clouded by the current absence of project sponsors.

Of the three options, an LNG export facility shows the highest rates of return in the reference and high price cases; however, it shows low rates of return in the low price case. The project risk associated with the LNG option is considerably less than that for the GTL option but greater than for the pipeline option. The LNG option is further undermined by the fact that there are large reserves of stranded natural gas elsewhere in the world that have a significant competitive advantage both because of their proximity to large consumer markets and because they would not require construction of an 800-mile supply pipeline through difficult terrain. Although there is definite interest in the LNG export option in Alaska, current advocates of the project have not yet secured letters of intent from potential buyers to purchase the LNG, nor do they have ownership of low-cost AD reserves, extensive experience in the management of large-scale projects, or strong financial backing. Finally, if shale deposits in the rest of the world turn out to be as rich in natural gas as those in the United States, worldwide demand for LNG could be reduced considerably from the levels that were expected just a few years ago.

Other Issues

The analysis described here focused primarily on the relative economics and risks associated with each of three options for a facility to bring natural gas from Alaska's North Slope to market. There are, in addition, a number of other issues that could be important in determining which facility option could proceed to construction and operation, four of which are described briefly below.

Resolving ownership issues for the Point Thomson natural gas condensate field lease. The State of Alaska has revoked the Point Thomson lease from the original leaseholders. Point Thomson holds approximately 8 trillion cubic feet of recoverable natural gas reserves, and without that supply, the existing North Slope AD reserves would be insufficient to supply a natural gas pipeline over a 20-year lifetime. The 35.4 trillion cubic feet of existing AD natural gas reserves on the Central North Slope includes Point Thomson's 8 trillion cubic feet, and without those reserves only 27.4 trillion cubic feet of North Slope gas reserves would be available, providing just 18.8 years of supply for a facility with a capacity of 4 billion cubic feet per day. As long as the ownership issue of the Point Thomson lease remains unresolved, the possibility of pursuing construction of any of the three options is diminished.

Obtaining permits for an Alaska natural gas pipeline in Canada. The pipeline option could encounter significant permitting issues in Canada, similar to those that have already been encountered by the Mackenzie Delta natural gas pipeline, whose construction has been significantly delayed as the result of a failure to secure necessary permits. Because there have been no filings for Canadian permits by any Alaska natural gas pipeline sponsor, the severity of this potential problem cannot be determined.

Exporting Alaska LNG to foreign consumers. Some parties in the United States have called for a halt to current exports of LNG from Alaska to overseas markets. If Alaska were prohibited from exporting LNG to overseas consumers, the financial risk associated with any new Alaska LNG facility would increase significantly, because the financial viability of an LNG facility would be tied solely to lower 48 natural gas prices, which are considerably lower than overseas natural gas prices.

Shipping GTL products through TAPS. The joint ownership structure of TAPS could prevent a minority owner from using the pipeline to ship GTL from the North Slope south to Valdez and on to market.

Conclusion

The *AEO2009* price cases project greater variance in oil prices than in natural gas prices. If those cases provide a reasonable reflection of potential future outcomes, then the pipeline option in this analysis would be exposed to less financial risk than the GTL and LNG options. Additionally, it is the only option that already has the commitment of energy companies capable of financing and constructing such a large, capital-intensive energy facility. The balance of the factors evaluated here points to an Alaska natural gas pipeline as being the most likely choice for bringing North Slope natural gas to market.

Natural Gas and Crude Oil Prices in *AEO2009*

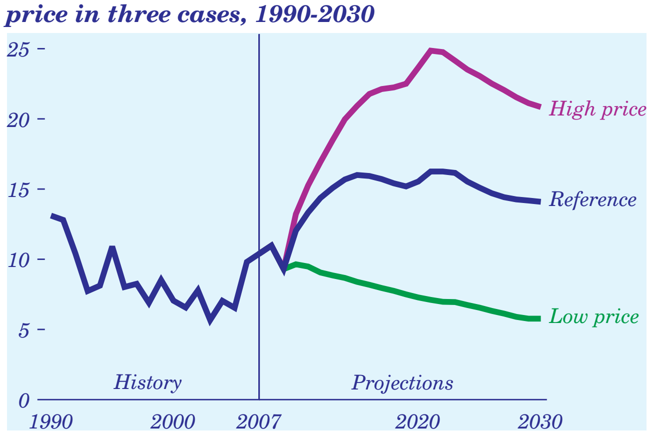
If oil and natural gas were perfect substitutes in all markets where they are used, market forces would be expected to drive their delivered prices to near equality on an energy-equivalent basis. The price of West Texas Intermediate (WTI) crude oil generally is denominated in terms of barrels, where 1 barrel has an energy content of approximately 5.8 million Btu. The price of natural gas (at the Henry Hub), in contrast, generally is denominated in million Btu. Thus, if the market prices of the two fuels were equal on the basis of their energy contents, the ratio of the crude oil price (the spot price for WTI, or low-sulfur light, crude oil) to the natural gas price (the Henry Hub spot price) would be approximately 6.0. From 1990 through 2007, however, the ratio of natural gas prices to crude oil prices averaged 8.6; and in the *AEO2009* projections from 2008 through 2030, it averages 7.7 in the low oil price case, 14.6 in the reference case, and 20.2 in the high oil price case (Figure 17).

The key question, particularly in the reference and high oil price cases, is why market forces are not expected to bring the ratios more in line with recent history. A number of factors can influence the ratio of oil prices to natural gas prices, as discussed below.

Crude Oil and Natural Gas Supply Markets

The methods and costs of transporting petroleum and natural gas are significantly different. The crude oil supply market is an international market, whereas the U.S. natural gas market is confined primarily to North America. In 2007, 43 percent of the oil and petroleum products consumed in the United States came by tanker from overseas sources [*66*]. In contrast, only 3 percent of total U.S. natural gas consumption came from overseas sources, by LNG tanker. Moreover, the domestic resource bases for the two fuels are significantly different. It is expected that lower 48 onshore natural gas resources will play a dominant role in meeting future domestic demand for natural gas, whereas imports of crude oil and petroleum products will continue to account for a significant portion of U.S. petroleum consumption.

Figure 17. Ratio of crude oil price to natural gas price in three cases, 1990-2030



Approximately 180 billion barrels of crude oil reserves and undiscovered resources are estimated to remain in the United States, equal to about 24 years of domestic consumption at 2007 levels; however, with more than 70 percent of those resources located offshore or in the Arctic, they will be relatively expensive to develop and produce [*67*]. The remaining U.S. natural gas resource base is much more abundant, estimated at 1,588 trillion cubic feet or nearly 70 years of domestic consumption at 2007 levels [*68*]. In addition, more than 70 percent of remaining U.S. natural gas resources are located onshore in the lower 48 States, which significantly reduces the cost of new domestic natural gas production.

The large domestic natural gas resource base has been estimated in one study to be sufficient to keep the long-run marginal cost of new domestic natural gas production between $5 and $8 (2007 dollars) per thousand cubic feet through 2030; however, the costs used in that study represent a period when drilling was unusually expensive, because oil and natural gas prices were high. In the future, cost for natural gas development and production could decline significantly as the demand for well drilling equipment and personnel comes into equilibrium with the available supply for those services [*69*].

In the *AEO2009* reference case, which projects a relatively low long-run marginal cost of natural gas, domestic production increasingly satisfies U.S. natural gas consumption. In 2030 more than 97 percent of the natural gas consumed in the United States is produced domestically, yet only 31 percent of the currently estimated U.S. natural gas resource base is produced by 2030. LNG imports remain a relatively small portion of U.S. natural gas supply, with their share peaking in 2018 at 6.5 percent and then falling to 3.5 percent in 2030.

The current opportunities for competition between oil and natural gas are relatively small in the United States (that is, the two U.S. supply markets are weakly linked). Although the relatively low costs projected for production of natural gas make it economically attractive in U.S. consumption markets where it competes with oil, particularly in the reference and high oil price cases, they are not low enough to make the United States a competitive source of natural gas for the world LNG market.

Also, large-scale conversion of lower 48 natural gas into liquid fuels is expected to be precluded by the inability of project sponsors to secure long-term natural gas supply contracts at guaranteed prices and volumes. Natural gas producers are unlikely to be able or willing to guarantee long-term volumes and prices.

Substitution of Natural Gas for Petroleum Consumption

In a relatively high oil price environment, as in the *AEO2009* reference and high oil price cases, consumers can reduce oil consumption through energy conservation and by switching to other forms of energy, such as natural gas, coal, renewables, and electricity. Natural gas is not necessarily the least expensive or quickest option to implement (in comparison with reducing transportation vehicle-miles traveled, for example).

In the residential, commercial, and electric power sectors, petroleum consumption is relatively small, accounting for only 6.5 percent of total U.S. petroleum consumption in 2007. Gradually converting all the petroleum consumption in those sectors to other fuels would have only a modest impact on natural gas consumption and prices.

In the industrial sector, the most feasible opportunity for substituting natural gas for petroleum is in heat and power uses, which amount to about 0.61 quadrillion Btu per year [*70*]; however, most petroleum consumption in the industrial sector (such as diesel and gasoline consumption by off-road vehicles in agricultural and construction activities; petroleum coke; refinery still gas, which is both produced and consumed in refineries; and road asphalt) is not well suited for conversion to natural gas. Also, there is considerable uncertainty about the extent to which petroleum feedstocks for chemical manufacturing could be replaced with natural gas before 2030. At a minimum, considerable downstream investment in chemical manufacturing processes would be required in order to convert to natural gas feedstock.

The greatest potential for large-scale substitution of natural gas for petroleum is in the transportation sector—especially, in local fleet vehicles refueled at a central facility, such as local buses, which consumed 0.18 quadrillion Btu in 2006 [*71*]. Wider use of natural gas as a fuel for transportation fleets also has been advocated; however, the idea faces significant hurdles given the relatively low energy density of natural gas; the cost, size, and weight of onboard storage systems; and the challenge of establishing a refueling infrastructure. In addition, any significant increase in natural gas use could raise natural gas prices sufficiently to reduce the ratio of natural gas prices to oil prices.

The Honda Civic GX and Civic LX-S vehicles provide a uniform basis for comparing the attributes of a natural-gas-fueled LDV (the GX) and a gasoline-fueled LDV (the LX-S) that use the same design platform (Table 13). The Honda GX is about 34 percent more expensive, carries 39 percent less fuel (resulting in a much shorter refueling range of about 200 to 220 miles), and provides 50 percent less cargo space, 19 percent less horsepower, and 15 percent less torque. Although natural gas has a high octane rating of 130, the GX horsepower and torque are reduced by the rate at which natural gas can be injected into the piston cylinders because of its lower energy density.

Although the higher cost and other disadvantages of natural gas vehicles could be offset at least partially

Table 13. Comparison of gasoline and natural gas passenger vehicle attributes

Attribute	*Gasoline-fueled 2009 Honda Civic LX-S*	*Natural-gas-fueled 2009 Honda Civic GX*	*Percent difference*
Sticker price (2007 dollars)	*18,855*	*25,190*	*34*
Curb weight (pounds)	*2,754*	*2,910*	*6*
Fuel tank capacity (gallons)	*13.2*	*8.0*	*-39*
Passenger space (cubic feet)	*90.9*	*90.9*	*—*
Cargo space (cubic feet)	*12.0*	*6.0*	*-50*
Horsepower at 6,300 rpm	*140*	*113*	*-19*
Torque at 4,300 rpm	*128*	*109*	*-15*

by their lower fuel costs, the lack of an extensive natural gas refueling infrastructure will remain a difficult hurdle to overcome. Consumers are unlikely to purchase natural gas vehicles if there is considerable uncertainty as to whether they can be refueled when and where they need to be. Similarly, service station owners are unlikely to install natural gas refueling equipment if the number of natural gas vehicles on the road is insufficient to pay for the infrastructure costs.

In 2008, there were only 778 service stations in the United States with natural gas refueling capability out of a total of more than 120,000 service stations [*72*]. Public refueling capability for natural gas, ethanol, methanol, and electric vehicles has fluctuated considerably over time, as the different vehicle options have gained and lost favor with the public. Even after the more than 15 years that these alternative fuel options have existed, fewer than 1 percent of the Nation's public service stations currently offer refueling capability for any alternative fuel.

Without an extensive public refueling network, the potential for market penetration by natural gas vehicles will be limited, and until a substantial number have been purchased, an extensive public refueling network is unlikely to develop. Market penetration by natural gas vehicles is also limited by the many alternatives that consumers have for reducing vehicle petroleum consumption, including buying smaller vehicles, reducing vehicle-miles traveled, and buying hybrid electric or, potentially, all-electric vehicles. In addition, price volatility in crude oil and natural gas markets obscures the long-term financial viability of natural gas vehicles. Consequently, *AEO2009* assumes that widespread adoption of natural gas vehicles in the United States is unlikely under current laws and policies.

Conclusion

Through 2030, an abundance of low-cost, onshore lower 48 natural gas resources, in conjunction with a limited set of opportunities to substitute natural gas for petroleum, is projected to raise the ratio of oil prices to natural gas prices above the historical range, as reflected in *AEO2009* reference and high oil price cases. Unless there is large-scale growth in the use of natural gas in the transportation sector, it is unlikely that fuel substitution in the other end-use sectors will be sufficient to reduce the price ratio significantly before 2030.

Electricity Plant Cost Uncertainties

Construction costs for new power plants have increased at an extraordinary rate over the past several years. One study, published in mid-2008, reported that construction costs had more than doubled since 2000, with most of the increase occurring since 2005 [*73*]. Construction costs have increased for plants of all types, including coal, nuclear, natural gas, and wind.

The cost increases can be attributed to several factors, including high worldwide demand for generating equipment, rising labor costs, and, most importantly, sharp increases in the costs of materials (commodities) used for construction, such as cement, iron, steel, and copper. Commodity prices continued to rise through most of 2008, but as oil prices dropped precipitously in the last quarter of the year, commodity prices began to decline. The most recent power plant capital cost index published by Cambridge Energy Research Associates (CERA) shows a slight decline in the index over the past 6 months, and CERA analysts expect further declines [*74*].

The current financial situation in the United States will also affect the costs of future power plant construction. Financing large projects will be more difficult, and as the slowing economy leads to lower demand for electricity, the need for new capacity may be limited. The resultant easing of demand for construction materials and equipment could lead to lower costs for materials and equipment when new investment does take place in the future. Fluctuating commodity prices, combined with the uncertain financial environment, increase the challenge of projecting future capital costs.

Because some plant types—coal, nuclear, and most renewables—are much more capital-intensive than others (such as natural gas), the mix of future capacity builds and fuels used can differ, depending on the future path of construction costs. If construction costs increase proportionately for all plant types, natural-gas-fired capacity will become more economical than more capital-intensive technologies. Over the longer term, higher construction costs are likely to lead to higher energy prices and lower energy consumption.

The *AEO2009* version of NEMS includes updated assumptions about the costs of new power plant construction. It also assumes that power plant costs will be influenced by the real producer price index for metals and metal products, leading to a decline in base construction costs in the later years of the projections. As sensitivities to the *AEO2009* reference case, several alternative cases assuming different trends in capital costs for power plant construction were used to examine the implications of different cost paths for new power plant construction.

Power Plant Capital Cost Cases

For the *AEO2009* reference case, initial capital costs for new generating plants were updated on the basis of costs reported in late 2007 and early 2008. The reference case cost assumptions reflect an increase of roughly 30 percent relative to the cost assumptions used in *AEO2008*, and they are roughly 50 percent higher than those used in earlier *AEO*s. Because there is a strong correlation between rising power plant construction costs and rising commodity prices, construction costs in *AEO2009* are tied to a producer price index for metals and metal products. The nominal index is converted to a real annual cost factor, using 2009 as the base year. The resulting reference case cost factor remains nearly flat for the next few years, then declines by a total of roughly 15 percent to the end of the projection in 2030. As a result, future capital costs are lower even before technology learning adjustments are applied. The same cost factor is applied to all technology types.

Although the correlation between construction costs and the producer price index for metals has been high in recent years, it is possible that costs could be affected by other factors in the future. There is also uncertainty in the metals index forecast, as with any projection. Therefore, the sensitivity cases do not use the metals index to adjust plant costs but instead use exogenous assumptions about future cost adjustment factors to provide a range of cost assumptions.

In the frozen plant capital costs case, base overnight construction costs for all new electricity generating technologies are assumed to remain constant at 2013 levels (which is when the cost factor peaks in the reference case). Because cost decreases still can occur as a result of technology learning, costs do decline slightly from 2013 to 2030 in the frozen costs case. In 2030, costs for all technologies are roughly 20 percent higher than in the reference case.

In the high plant capital costs case, base overnight construction costs for all new generating plants are assumed to continue increasing throughout the projection, by assuming that the cost factor increases by 25 percentage points from 2013 to 2030. Again, cost decreases still can occur as a result of technology, partially offsetting the increases. For most technologies, however, costs in 2030 are above current costs. Plant construction costs in 2030 in the high plant capital costs case are about 50 percent higher than in the reference case.

In the falling plant capital costs case, base overnight construction costs for all generating technologies fall more rapidly than in the reference case, starting in 2013. In 2030, the cost factor is assumed to be 25 percentage points below the reference case value.

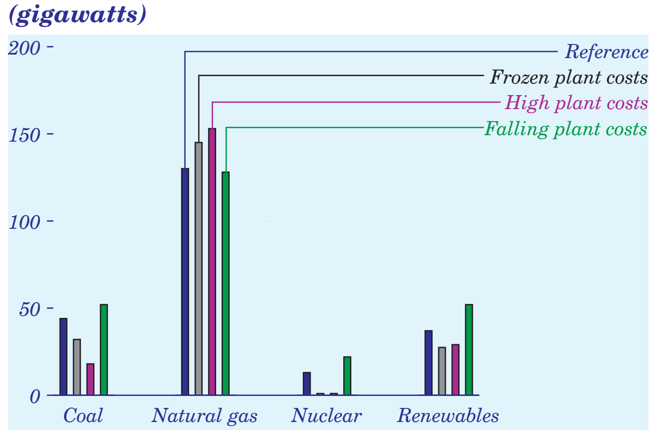
Results

Capacity Additions

Overall capacity requirements, as well as the mix of generating types, change across the alternative plant cost cases. In the reference case, 259 gigawatts of new generating capacity is added from 2007 to 2030. In the frozen and high plant costs cases, capacity additions fall to 247 gigawatts and 237 gigawatts, respectively. In the falling plant costs case, additions increase to 288 gigawatts.

In all the plant costs cases, the vast majority of new capacity is fueled by natural gas, in part because coal, nuclear, and renewable technologies are more capital-intensive; however, the fuel shares of total builds do differ among the cases (Figure 18). Coal-fired plants make up 18 percent of all the new capacity built in the reference case through 2030. Across the alternative cases, their share ranges from 9 percent to 20 percent. In the frozen plant costs and high plant costs cases, no nuclear capacity is built beyond the 1.2 gigawatts of planned additions. In the falling plant

Figure 18. Cumulative additions to U.S. electricity generation capacity by fuel in four cases, 2008-2030 (gigawatts)



costs case, more than 20 gigawatts of nuclear capacity is built. Renewable capacity makes up a 22-percent share of all new capacity built in the reference case; the renewable share remains between 21 and 22 percent in the high plant costs and frozen plant costs cases and increases to 25 percent in the falling plant costs case.

Electricity Generation and Prices

Differences among the projections for generation fuel mix in the different cases are not as large as the differences in the projections for capacity additions, because the construction cost assumptions do not affect the operation of existing capacity. Coal maintains the largest share of total generation through 2030, ranging from 44 percent to 47 percent in 2030 across the four cases (Figure 19). The renewable share in 2030 is nearly the same in all the cases, from 14 percent to 15 percent, because all the cases assume that the same State and regional RPS goals must be met. In the frozen and high plant costs cases, biomass co-firing is used predominantly to meet RPS requirements, rather than investment in new renewable capacity. In the falling plant costs case, generation from biomass co-firing is less than projected in the reference case, and wind generation provides more of the renewable requirement.

Nuclear generation provides 18 percent of total generation in 2030 in the reference case, compared with 16 percent in the frozen and high plant costs cases and 19 percent in the falling plant costs case. Natural-gas-fired generation, typically the source of marginal electricity supply, follows an opposite path, increasing by 22 percent from the reference case projection in 2030 in the high plant costs case and by 14 percent in the frozen plant costs case, and decreasing by 11 percent in the falling plant costs case. As a result, delivered natural gas prices vary among the different cases, increasing by as much as 10 percent from the reference case projection in the high plant costs case and decreasing by 6 percent in the falling plant costs case. Electricity prices in 2030, following the trend in natural gas prices, are 5 percent higher than the reference case projection in the high plant costs case (where electricity prices also rise in response to higher construction costs) and 5 percent lower than the reference case projection in the falling plant costs case (Figure 20).

Tax Credits and Renewable Generation

Background

Tax incentives have been an important factor in the growth of renewable generation over the past decade, and they could continue to be important in the future. The Energy Tax Act of 1978 (Public Law 95-618) established ITCs for wind, and EPACT92 established the Renewable Electricity Production Credit (more commonly called the PTC) as an incentive to promote certain kinds of renewable generation beyond wind on the basis of production levels. Specifically, the PTC provided an inflation-adjusted tax credit of 1.5 cents per kilowatthour for generation sold from qualifying facilities during the first 10 years of operation. The credit was available initially to wind plants and facilities that used "closed-loop" biomass fuels [*75*] and were placed in service after passage of the Act and before June 1999.

The 1992 PTC has lapsed periodically, but it has been renewed before or shortly after each expiration date, typically for an additional 1- or 2-year period. In addition, eligibility has been extended to generation from many different renewable resources [*76*], including

Figure 19. Electricity generation by fuel in four cases, 2007 and 2030 (billion kilowatthours)

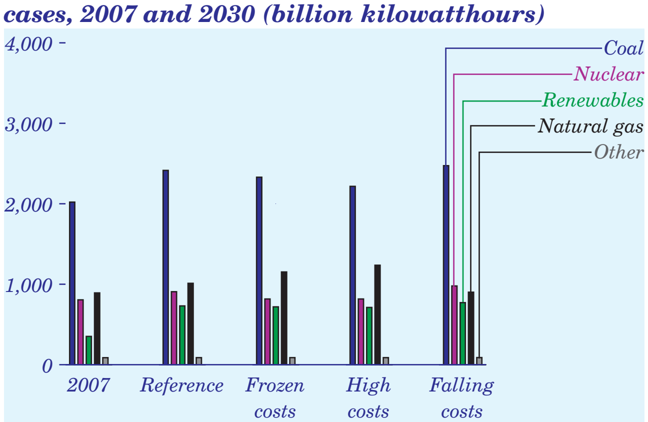
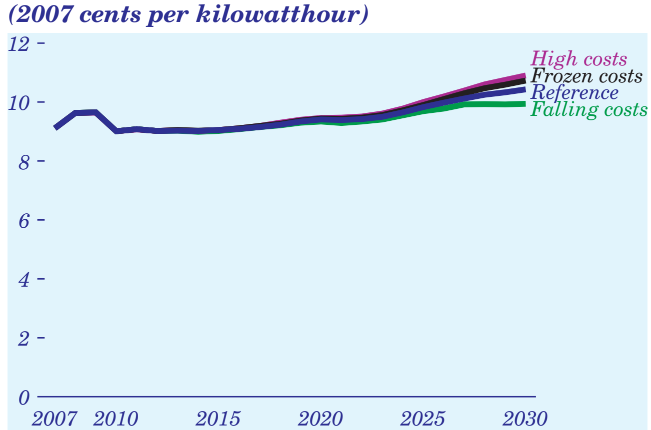


Figure 20. Electricity prices in four cases, 2007-2030 (2007 cents per kilowatthour)

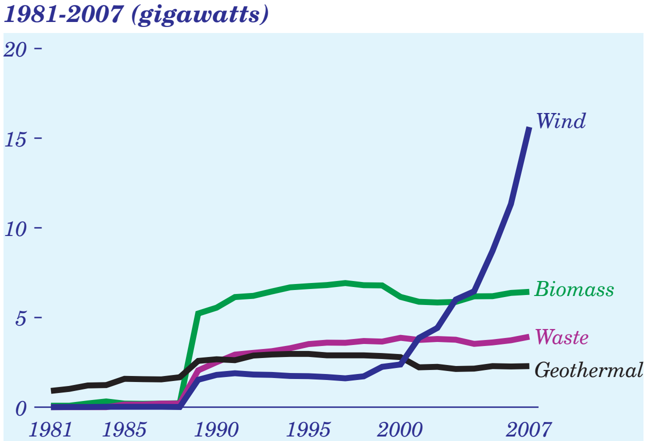


poultry litter, geothermal energy [77], certain hydroelectric facilities [78], "open-loop" biomass [79], landfill gas, and, most recently, marine energy resources. Open-loop biomass and landfill gas currently receive one-half the PTC value (1 cent rather than the current inflation-adjusted 2 cents available to other eligible resources). Eligibility of new projects for the PTC was set to expire at the end of 2008, but it was extended to December 31, 2009, for wind capacity and to December 31, 2010, for other eligible renewable facilities [80].

As this publication was being prepared, the PTC was further extended and modified by ARRA2009, which extends eligibility for the PTC to December 31, 2012, for wind projects and to December 31, 2013, for all other eligible renewable resources. In addition, project owners may elect to receive a 30-percent ITC in lieu of the PTC, and may further elect to receive an equivalent grant in lieu of the ITC. Project owners electing the grant must commence their projects during 2009 or 2010. These recently passed provisions are not included in *AEO2009*.

The PTC has contributed significantly to the expansion of the wind industry over the past 10 years. Since 1998, wind capacity has grown by an average of more than 25 percent per year (Figure 21). Although some of the more recent growth may be attributable to State programs, especially the mandatory RPS programs now in effect in 28 States and the District of Columbia, the importance of the PTC is evidenced by the growth of wind power installations in States without renewable mandates, either today or at the time the installations were constructed, and by the significant drop in new wind installations during periods when the PTC has been allowed to lapse.

Figure 21. Installed renewable generation capacity, 1981-2007 (gigawatts)



Although other renewable generation facilities, such as geothermal or poultry litter plants, have been able to claim the PTC, none has grown as dramatically as wind power. Possible explanations for their slower rate of expansion include longer construction lead times and less favorable economics for some facilities. In addition, some provisions of the PTC may limit its ability to be used fully or efficiently for some projects. For example, project owners that do not pay Federal income taxes (such as municipal utilities and rural electric cooperatives) cannot claim the PTC, even though they may be eligible for other Federal assistance. Also, the owners of for-profit projects must have sufficient tax liability to claim the full PTC, and their eligibility for PTC payments may be limited by the Federal alternative minimum tax law.

The wind industry, in particular, has developed several alternative ownership and finance structures to help minimize the impact of the limitations [81]. There is some evidence, however, that the restrictions reduce the value of the PTC to project owners. In addition, the financial crisis of 2008 may exacerbate the problems for some projects [82]. As part of ARRA2009, developers may, for a limited time, convert the PTC into a 30-percent ITC and then into a grant. This provision may lessen the impact of the financial crisis on the ability of wind developers to use the PTC. As noted above, the provisions of ARRA2009 are not included in *AEO2009*.

Future Impacts

Because *AEO2009* represents only those laws and policies in effect on or before November 4, 2008, the renewable energy PTC is assumed to expire at the end of 2009 for wind and at the end of 2010 for other eligible renewables; however, the program has a long history of renewal and extension, and there is considerable interest, both in Congress and in the renewable energy industry, in keeping the credit available over the longer term, as seen in the recent extension to 2013.

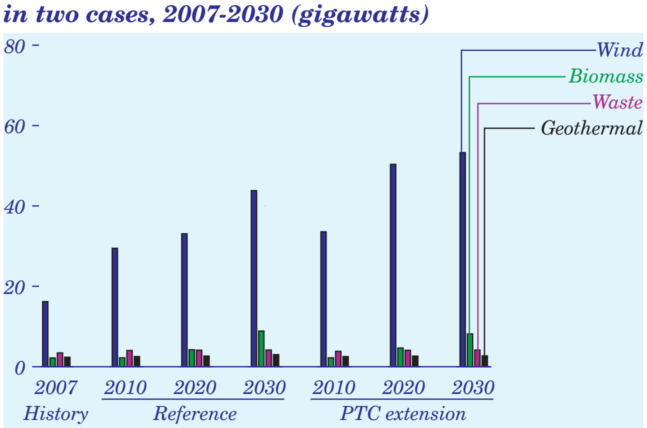
To examine the potential impacts of a PTC extension, *AEO2009* includes a production tax credit extension case that examines the potential impacts of extending the current credit through 2019. Because EIA does not develop or advocate policy, the PTC extension case is included here only to assess the potential impacts of such an extension and should not be construed as a proposal for, or endorsement of, any legislative action.

Aside from the expiration date, no changes in current PTC provisions are assumed in the PTC extension case. The credit is valued at 2 cents per kilowatthour (in 2008 dollars, adjusted for projected inflation rates) for wind, geothermal, and hydroelectric generation and at 1 cent per kilowatthour for biomass and landfill gas [*83*]. It is assumed that all eligible facilities will receive the credit for the first 10 years of plant operation, and that they will use the credit efficiently and completely, without further modification of the law. The extension is assumed to be continuous over the 10-year period and not subject to the periodic cycle of expiration and renewal that has affected the PTC in the past.

For wind power installations, a 10-year extension of the PTC results in significantly more capacity growth than in the reference case (Figure 22). In the near term, capacity increases would be comparable to those seen over the past several years, followed by a period of several years in which the capacity expansion is slower, corresponding to a projected lull in electricity demand growth. Significant additional growth in wind capacity occurs thereafter, before the assumed 2019 expiration date, with total capacity increasing to approximately 50 gigawatts in 2020, as compared with 33 gigawatts in the reference case. Additional capacity expansion occurs after 2020 in both cases, particularly in the reference case, where 11 gigawatts of installed capacity is added from 2020 to 2030 as compared with 2 gigawatts in the PTC extension case.

For eligible technologies other than wind, no significant changes in capacity installations are projected in the PTC extension case relative to the reference case. In part, this may be a result of the shorter lead times

Figure 22. Installed renewable generation capacity in two cases, 2007-2030 (gigawatts)



associated with wind technology: wind plants can be built before the projected slowdown in electricity demand growth after 2010, potentially “crowding out” other PTC-eligible investments. In addition, the economics for wind installations are fundamentally more favorable than for other PTC-eligible resources, and the resource base for wind power is more widespread.

Because eligible renewable generation still accounts for a relatively small share of total U.S. electricity generation, the PTC extension case has relatively minor impacts outside the markets for renewable generation. A 10-year extension of the PTC reduces average electricity prices in 2020 by approximately 1 percent relative to the reference case. The extension costs the Federal Government approximately $7.7 billion from 2010 to 2019 (in 2007 dollars) [*84*], while cumulative savings on electricity expenditures from 2010 to 2019 total about $13 billion in comparison with the reference case.

Total electricity generation in 2020 in the PTC extension case is less than 0.5 percent greater than in the reference case. The increase in wind-powered electricity generation in the PTC extension case primarily offsets the use of natural gas in the power sector, reducing natural-gas-fired generation by about 5 percent in 2020 compared to the reference case. Impacts on other generation fuels generally are less than 1 percent. The maximum reduction in CO_2 emissions from the electric power sector (occurring before 2020) is about 0.5 percent compared to the reference case.

Greenhouse Gas Concerns and Power Sector Planning

Background

Concerns about potential climate change driven by rising atmospheric concentrations of GHGs have grown over the past two decades, both domestically and abroad. In the United States, potential policies to limit or reduce GHG emissions are in various stages of development at the State, regional, and Federal levels. In addition to ongoing uncertainty with respect to future growth in energy demand and the costs of fuel, labor, and new plant construction, U.S. electric power companies must consider the effects of potential policy changes to limit or reduce GHG emissions that would significantly alter their planning and operating decisions. The possibility of such changes may already be affecting planning decisions for new generating capacity.

California and 10 States in the Northeast are moving forward with mandatory emissions reduction programs. For 10 Northeastern States, 2009 is the inaugural year of the RGGI, a cap-and-trade program for power plant emissions of CO_2 [*85*]. RGGI sets a cap of 188 million metric tons CO_2 in 2009 for power generating facilities with rated capacity greater than 25 megawatts and lowers that cap annually to 169 million metric tons in 2018. Although RGGI represents the first legally binding regulation of CO_2 emissions in the United States and will influence future decisions about investments in generating capacity, its overall impact is expected to be modest. In 2006, CO_2 emissions from power plants covered by RGGI accounted for only 7 percent of the CO_2 emitted from all U.S. power plants, and their total 2006 emissions—at 164 million metric tons—already were below the 2018 goal of 169 million metric tons.

Other regional initiatives also are being developed. The WCI consists of seven Western U.S. States and four Canadian Provinces [*86*]. A draft rule released in July 2008 aims at an economy-wide cap on six GHGs, including CO_2. The cap level and details of the program design still are being developed. In November 2007, the governors of 10 Midwestern States signed the Midwestern Greenhouse Gas Reduction Accord [*87*], currently in the preliminary stages of development, with the broad goal of creating a multi-sector, interstate cap-and-trade program for the member States.

At the State level, 37 individual States have released State-specific climate change mitigation plans; however, the only legally binding requirements outside the RGGI States are in California, which has passed Assembly Bill (A.B.) 32, the Global Warming Solutions Act of 2006 [*88*]. A.B. 32 aims to reduce the State's GHG emissions to 1990 levels by 2020. Although specific regulations associated with A.B. 32 remain to be finalized, the law requires that policies be designed to meet the reduction targets.

At the national level, numerous bills to reduce GHGs have been introduced in the U.S. Congress in recent years. As of July 2008, a total of 235 bills, amendments, and resolutions addressing climate change in some form had been introduced in the 110th Congress. Nine of the bills—three in the House and six in the Senate—specifically proposed a cap-and-trade system for CO_2 and other GHGs. Of the nine, the Boxer-Lieberman-Warner Climate Security Act (S. 3036) progressed the farthest, reaching the floor of the Senate in June 2008 [*89*].

Even without the enactment of national emissions limits, many State utility regulators and the banks that finance new power plants are requiring assessments of GHG emissions for new projects. For example, many State public utility commissions now are requiring that utilities review projected CO_2 emissions in their integrated resource plans (IRPs) [*90*]. The IRP process is intended to keep public utility regulators at the State level informed of their utilities' strategies to meet future demand and supply. The treatment of projected CO_2 emissions has differed among utilities. Some have included an emissions price in their base case scenarios; others have done so in alternative scenarios. Typically, the emissions prices used have ranged from $5 to $80 per metric ton.

Several major banks in the United States also have decided to include future CO_2 emissions as a factor in their decisionmaking processes for financing of new power plants. In February 2008, Citibank, JPMorgan Chase, and Morgan Stanley announced the formation of "The Carbon Principles," which provide climate change guidelines for advisors and lenders to power companies in the United States [*91*]. Adopters of the principles would commit to:

- Encourage 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
- 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," and use the results of this diligence as a contribution to the determination whether a transaction is eligible for financing and under what terms
- 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.

Reflecting Concerns Over Greenhouse Gas Emissions in AEO2009

Key questions in the development of the *AEO2009* projections included the degree to which ongoing debate about potential climate change policies, together with the actions taken by State regulators and the financial community, already are affecting planning and operating decisions in the electric power sector, and how best to capture those impacts in the analysis. Although existing plants continue to be operated on a least-cost basis without adjustments for GHG emissions levels, concerns about GHG emissions do appear to be having an impact on decisions about new plants.

When regulators and banks are reviewing the projected GHG emissions of new plants in their investment evaluation process, they are implicitly adding a cost to some plants, particularly those that involve GHG-intensive technologies. The implicit cost could be represented by adding an amount to the operating costs of plants that emit CO_2 to reflect the value of emissions; however, doing so would affect not only planning decisions for new capacity but also future utilization decisions for all plants—something that does not appear to be occurring on a widespread basis in markets today.

Alternatively, the costs of building and financing new GHG-intensive capacity could be adjusted to reflect the implicit costs being added by utilities, their regulators, and the financial community. This option better reflects current market behavior, which is focused on discouraging power companies from investing in high-emission technologies. As a result, in the *AEO2009* reference case, a 3-percentage-point increase is added to the cost of capital for investments in GHG-intensive technologies, such as coal-fired power plants without CCS and CTL plants.

Although the 3-percentage-point adjustment is somewhat arbitrary, its impact in levelized cost terms is similar to that of a $15 fee per metric ton of CO_2 for investments in new coal-fired power plants without CCS—well within the range of the results of simulations that utilities and regulators have prepared. The adjustment should be seen not as an increase in the actual cost of financing but rather as representing the implicit costs being added to GHG-intensive projects to account for the possibility that, eventually, they may have to purchase allowances or invest in other projects that offset their emissions.

Two alternative cases were prepared to show how the representation of investment behavior in the electric power sector affects the *AEO2009* reference case projections, given uncertainty about the evolution of potential GHG policies. In the no GHG concern case, the cost-of-capital adjustment for GHG-intensive technologies is removed to represent a future in which concern about GHG emissions wanes or efforts to implement GHG reduction regulations subside. This case reflects an approach similar to that used for the reference case in past *AEO*s. In the LW110 case, the GHG emissions reduction policy called for in S. 2191, the Lieberman-Warner Climate Security Act of 2007 introduced in the 110th Congress, is analyzed [*92*]. This case illustrates a future in which an explicit Federal policy limiting GHG emissions is enacted, affecting both planning and operating decisions.

Because the projected impact of any policy to reduce GHG emissions will depend on its detailed specifications—which may differ significantly from those in the LW110 case—results from the LW110 case do not apply to other past or future policy proposals. Rather, projections in the two alternative cases illustrate the potential importance to the electric power industry of GHG policy changes, and why uncertainty about such changes weighs heavily on planning and investment decisions.

Findings

The imposition of a GHG reduction policy would affect all aspects of the electric power industry, including decisions about the types of plants built to meet growing electricity demand, the fuels used to generate electricity, the prices consumers will pay in the future, and GHG emissions from electric power plants.

Capacity

Generating capacity investment decisions in the two sensitivity cases differ from those in the *AEO2009* reference case (Figure 23). The overall amounts of new capacity added in the reference case and the no GHG concern case are similar, but there are differences in the mix of plant types built. New coal builds without CCS are higher in the no GHG concern case than in the reference case, as the concern that new regulations might be coming dampens investment in new coal-fired plants in the reference case. On the other hand, new natural-gas-fired plants, which are not as GHG-intensive, are more attractive economically in the reference case. In an environment of uncertainty about future regulation of CO_2 emissions, natural gas becomes the primary choice for new capacity additions; without such uncertainty, coal remains the primary choice. Concern about possible new regulations plays a role in the construction of a modest amount of nuclear power and renewable energy capacity in the reference case, but other incentives also influence their selection. It is unclear whether utilities would be willing to incur the high costs of building new nuclear plants in the absence of concerns about potential GHG regulations.

The cap-and-trade policy adopted in the LW110 case changes the mix of capacity additions significantly relative to the other cases. The adjusted cost of capital in the reference case increases the cost of building new GHG-intensive facilities but does not change the cost of operating those plants already in service or new plants once they are built. The introduction of an explicit cap on GHG emissions adds a cost to the emissions generated from existing and new facilities, making carbon-intensive coal-fired plants more expensive to build and operate. As a result, approximately 35 percent of the existing fleet of coal-fired plants is retired by 2030 in the LW110 case, and 33 percent more new capacity is added than in the reference case, replacing the retired capacity. The explicit GHG emission constraint results in the construction of a different mix of new capacity additions, with new nuclear power, renewables, and coal with CCS making up a majority of the capacity added. The new capacity additions lead to a significantly different portfolio of generation assets and generation by fuel in 2030.

The results show that implementation of the LW110 case would lead to greater use of coal with CCS, nuclear, and renewable capacity; however, there is significant uncertainty around the projections. New coal-fired plants with CCS equipment have not been fully commercialized, and it is unclear when they might be and what they would cost. Similarly, a rapid expansion of nuclear capacity also would present challenges, including uncertainty both about the cost of the plants and about public acceptance of them. There also may be limits to a rapid expansion of renewable generation, because many of the best resources are located far from electricity load centers. Previous EIA analysis has found that, if the expansion is limited, the electricity industry may rely more heavily on new natural-gas-fired plants to reduce GHG emissions, leading to higher allowance costs and higher electricity prices [*93*].

Generation by Fuel

Among the three cases examined, total electricity generation in 2030 is lowest in the LW110 case (Figure 24 and Table 14). The explicit cap raises the price of electricity, which over time slows the growth in demand for electricity, lowering generation requirements. The opposite is true in the no GHG concern case, where lower electricity prices stimulate higher demand for electricity and increase generation requirements. Generation from coal drops the most in the LW110 case. Relative to the *AEO2009* reference case, the explicit GHG emission cap reduces the total amount of electricity generated from all coal-fired plants by 33 percent and the amount from coal-fired plants without CCS by 68 percent in 2030, as older coal plants are retired and the marginal costs of units still operating, which must hold allowances, are higher. Despite their high initial capital costs, new coal-fired units with CCS are less expensive to operate than traditional coal-fired plants without CCS, given a tight constraint on CO_2 emissions. The shares of renewables and nuclear power in the generation mix also increase significantly in the LW110 case, as low-emissions technologies are added to meet the growing demand for electricity.

Electricity Prices

Projected electricity prices are lowest in the no GHG concern case, where there is no cap on emissions, and coal-fired plants with relatively low fuel costs

Figure 23. Cumulative additions to U.S. generating capacity in three cases, 2008-2030 (gigawatts)

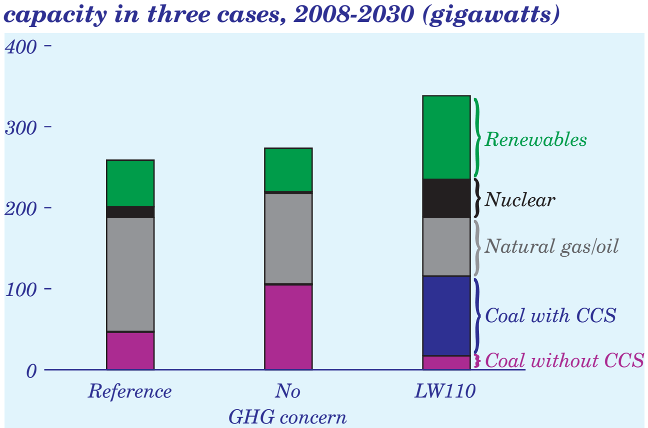
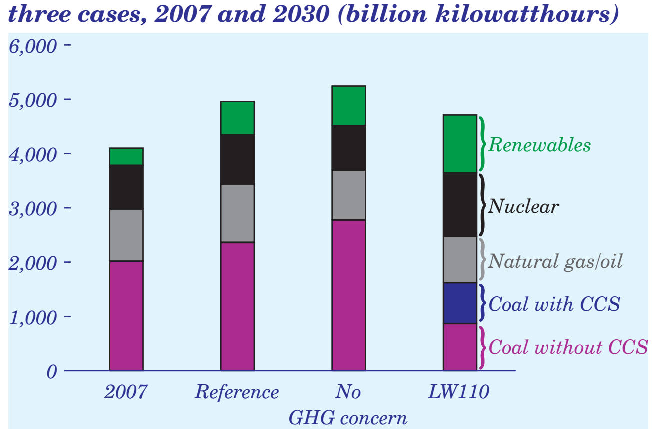


Figure 24. U.S. electricity generation by source in three cases, 2007 and 2030 (billion kilowatthours)



continue to dominate the mix of generation (Figure 25). Greater reliance on natural gas in the reference case leads to higher electricity prices when construction of carbon-intensive facilities, including coal-fired plants, is dampened because of uncertainty about possible GHG regulations.

An explicit cap on GHG emissions adds an additional cost to the generation of electricity from CO_2-emitting sources. To lower emissions in the LW110 case, the industry turns to more expensive resources and allowance purchases to cover remaining emissions. Therefore, electricity generated from fossil fuels becomes more expensive, while higher priced low-emitting sources, such as nuclear, renewables, and coal with CCS, become more cost-competitive. As a result, the cost of generating electricity increases. In 2030, the price of electricity is 22 percent higher in the LW110 case than in the reference case and 26 percent higher than in the no GHG concern case.

Emissions

The electric power sector is expected to play a major role in any effort to reduce GHG emissions in the United States (Figure 26). The sector accounted for 41 percent of energy-related CO_2 emissions in 2007, and its emissions are projected to grow. On the other hand, a wide array of fuels and technologies with

Table 14. Summary projections for alternative GHG cases, 2020 and 2030

		2020			2030		
State	2007	Reference	No GHG concern	LW110	Reference	No GHG concern	LW110
Delivered energy prices (2007 dollars per unit)							
Motor gasoline (per gallon)	2.80	3.60	3.59	3.85	3.88	3.79	4.37
Jet fuel (per gallon)	2.17	2.99	2.97	3.30	3.32	3.24	3.95
Diesel (per gallon)	2.74	3.47	3.44	3.78	3.83	3.72	4.45
Natural gas (per thousand cubic feet)							
Residential	13.05	12.85	12.64	14.84	14.71	14.29	18.97
Electric power	7.22	7.35	7.15	9.01	8.94	8.47	12.51
Coal, electric power sector (per million Btu)	1.78	1.92	1.94	5.25	2.04	2.16	8.72
Electricity (cents per kilowatthour)	9.11	9.41	9.33	10.23	10.43	10.08	12.70
Energy consumption (quadrillion Btu)							
Liquids	40.75	38.93	38.97	38.35	41.60	41.66	39.87
Natural gas	23.70	24.09	23.78	22.88	25.04	24.02	22.45
Coal	22.74	23.98	24.80	20.30	26.56	30.62	16.40
Nuclear power	8.41	8.99	8.77	9.36	9.47	8.58	12.21
Renewable/other	6.05	9.26	9.28	11.15	10.67	10.71	15.24
Electricity imports	0.11	0.06	0.06	0.10	0.10	0.04	0.31
Total	**101.77**	**105.31**	**105.65**	**102.16**	**113.43**	**115.62**	**106.46**
Electricity generation (billion kilowatthours)							
Petroleum	66	58	58	55	60	61	53
Natural gas	892	898	852	828	1,012	854	803
Coal	2,021	2,156	2,235	1,846	2,415	2,779	1,621
Nuclear power	806	862	840	897	907	822	1,170
Renewable	352	617	619	789	730	728	1,063
Other (includes pumped storage)	22	28	28	27	28	27	27
Total	**4,159**	**4,618**	**4,632**	**4,442**	**5,153**	**5,272**	**4,737**
Carbon dioxide emissions (million metric tons)							
Electric power sector, by fuel							
Petroleum	66	40	40	37	41	42	36
Natural gas	376	357	340	325	378	321	260
Coal	1,980	2,089	2,142	1,685	2,299	2,494	868
Other	12	12	12	12	12	12	13
Total	**2,433**	**2,497**	**2,534**	**2,059**	**2,729**	**2,869**	**1,176**
Total carbon dioxide emissions, all sectors	**5,991**	**5,982**	**6,044**	**5,436**	**6,414**	**6,745**	**4,615**

various emission levels are used in the electric power sector, providing some flexibility for altering emissions levels without turning to wholly unknown technologies or requiring end-use consumers to purchase any new equipment. Increases in CO_2 emissions from

the electric power sector are projected to continue through 2030 in the no GHG concern case and the *AEO2009* reference case. In the no GHG concern case, emissions are expected to rise as demand for electricity increases and coal's share of the national generation mix grows to 53 percent in 2030. Emissions also continue to increase through 2030 in the reference case but at a slower rate because of the reduced reliance on coal for generation.

In the LW110 case, in contrast, CO_2 emissions from the electric power sector are projected to fall significantly over time. In this case, CO_2 emissions from the electric power sector in 2030 are projected to be 52 percent below their 2007 level and 57 percent below the level in the reference case.

Figure 25. U.S. electricity prices in three cases, 2005-2030 (2007 cents per kilowatthour)

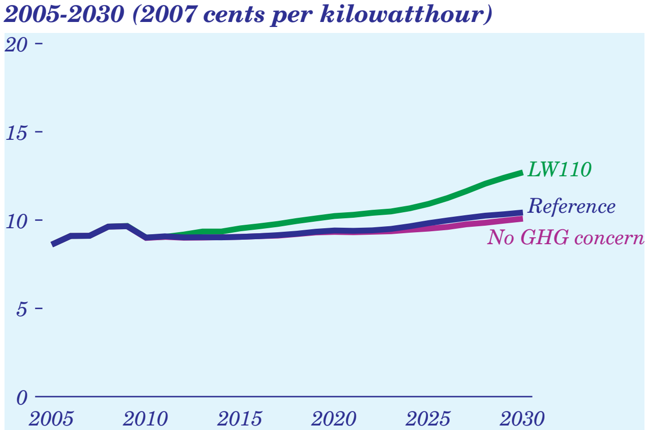
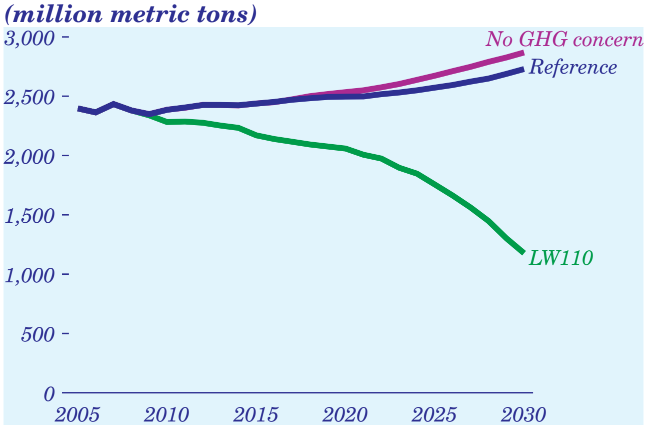


Figure 26. Carbon dioxide emissions from the U.S. electric power sector in three cases, 2005-2030 (million metric tons)



Endnotes for Issues in Focus

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53. U.S. House of Representatives, 110th Congress, "Energy Improvement and Extension Act of 2008," H.R. 6049, web site www.govtrack.us/congress/bill.xpd?bill=h110-6049.
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55. A. Bandivadekar, K. Bodek, L. Cheah, C. Evans, T. Groode, J. Heywood, E. Kasseris, M. Kromer, and M. Weiss, *On the Road in 2035: Reducing Transportation's Petroleum Consumption and GHG Emissions*, LFEE 2008-05 RP (Cambridge, MA: Massachusetts Institute of Technology, July 2008), web site http://web.mit.edu/sloan-auto-lab/research/beforeh2/otr2035.
56. The Alaska OCS has not been subject to leasing restrictions since 2007. In the North Aleutian Basin of Alaska, the Congressional moratorium was lifted in 2004, and the Presidential withdrawal was lifted in 2007.
57. See Legislation and Regulations, "Regulations Related to the Outer Continental Shelf Moratoria and Implications of Not Renewing the Moratoria."
58. The ban on areas in the Eastern and Central Gulf of Mexico through 2022 imposed by the Gulf of Mexico Energy Security Act of 2006 remains in place. *AEO2009* assumes no restrictions on drilling in the Atlantic and Pacific OCS through 2030.
59. U.S. Department of the Interior, Minerals Management Service, *Draft Proposed Outer Continental Shelf (OCS) Oil and Gas Leasing Program 2010-2015* (Washington, DC, January 2009), web site www.mms.gov/5%2Dyear/2010-2015New5-YearHome.htm.

60. This discussion is based largely on data from U.S. Department of Energy, Office of Naval Petroleum and Oil Shale Reserves, *Strategic Significance of America's Oil Shale Resource, Volume II, Oil Shale Resources, Technology and Economics* (Washington, DC, March 2004), web site www.fossil.energy.gov/ programs/reserves/npr/publications/npr_strategic_significancev2.pdf.
61. The Fischer assay is a standardized laboratory test for determining oil and natural gas yields from oil shale rock.
62. Energy Information Administration, *Advance Summary, U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves, 2007 Annual Report*, DOE/EIA-0216(2007) Advance Summary (Washington, DC, October 2008), Table 1, p. 5, web site www.eia.doe.gov/ pub/oil_gas/natural_gas/data_publications/advanced_summary/current/adsum.pdf.
63. The GTL option is represented in NEMS in the form of facilities with capacities of 34,000 barrel per day that can be added incrementally when oil and petroleum product prices are sufficiently high to make their operation profitable.
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65. K.W. Sherwood and J.D. Craig, *Prospects for Development of Alaska Natural Gas: A Review as of January 2001* (Anchorage, AK: U.S. Department of Interior, Minerals Management Service, Resource Evaluation Office), Chapters 4 and 5, web site www.mms.gov/ alaska/re/natgas/akngas2.pdf. Resource recovery costs were updated for this analysis, to reflect the escalation of drilling costs over time.
66. All 2007 oil and natural gas supply and consumption figures are taken from Energy Information Administration, *Annual Energy Review 2007*, DOE/EIA-0384 (2007) (Washington, DC, June 2008), web site www.eia.doe.gov/emeu/aer/contents.html.
67. Crude oil and natural gas resource figures are those represented in NEMS, which are based on the most current U.S. Geological Survey and U.S. Minerals Management Service undiscovered resource estimates. They include proven crude oil and natural gas reserves as of January 1, 2007.
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73. Cambridge Energy Research Associates, "Construction Costs for New Power Plants Continue to Escalate: IHS CERA Power Capital Costs Index" (press release, May 27, 2008), web site www.cera.com/aspx/cda/public1/news/pressReleases/pressReleaseDetails.aspx?CID=9505.
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75. Closed-loop biomass is defined as any organic material from a plant that is cultivated exclusively for use in producing electricity at a qualifying facility.
76. Solar installations received the credit for a brief period, from 2004 to 2005. Certain types of coal facilities can claim a tax credit under Section 45 of the U.S. Internal Revenue Code, and some qualifying nuclear plants may also claim a production tax credit.
77. Geothermal energy is also eligible for a 10-percent Federal ITC, but a facility cannot claim both credits.
78. Eligibility is limited to "incremental" generation resulting from capital investments at existing hydroelectric facilities.
79. Open-loop biomass includes waste and residue materials from certain agricultural, forestry, and urban or industrial processes.
80. Marine resources must be in service by December 31, 2011, to be eligible for the PTC.
81. See, for example, J.P. Harper, M.D. Karcher, and M. Bolinger, *Wind Project Financing Structures: A Review & Comparative Analysis*, LBNL-63434 (Berkeley, CA: Lawrence Berkeley National Laboratory, September 2007), web site http://eetd.lbl.gov/EA/EMP/reports/63434.pdf.
82. C. Carlson and G.E. Metcalf, "Energy Tax Incentives and the Alternative Minimum Tax," *National Tax Journal*, Vol. 61, No. 3 (September 2008), web site www.entrepreneur.com/tradejournals/article/190149936.html.

83. Because the projection does not show any use of closed-loop resources, the open-loop credit value is assumed. EIA currently does not model marine energy technologies.
84. Using a real discount rate of 7 percent. PTC costs for 2009, estimated at $3.6 billion, are not included.
85. The participating States are New York, New Jersey, Connecticut, Massachusetts, Maine, New Hampshire, Vermont, Rhode Island, Delaware, and Maryland. See Regional Greenhouse Gas Initiative, web site www.rggi.org/states.
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91. 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.
92. The LW110 case is based on S. 2191, which is the most recent GHG bill analyzed by EIA as of November 2008. The choice is not meant to imply that EIA supports or does not support S. 2191 or any other particular past or future proposal.
93. Energy Information Administration, *Energy and Economic Impacts of S. 2191, the Lieberman-Warner Climate Security Act of 2007*, SR/OIAF/2008-01 (Washington, DC, April 2008), web site www.eia.doe.gov/oiaf/servicerpt/s2191/index.html.

Market Trends

The projections in *AEO2009* 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, reflecting known technology and technological and demographic trends. *AEO2009* generally assumes that current laws and regulations are maintained throughout the projections. Thus, the projections provide a policy-neutral reference case that can be used to analyze policy initiatives. EIA does not propose or advocate future legislative or regulatory changes.

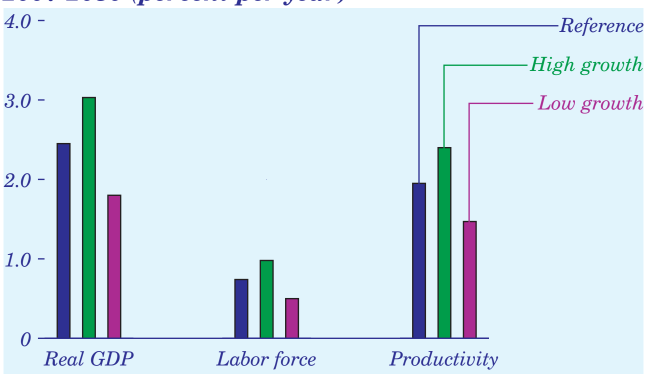
Because energy markets are complex, models are simplified representations of energy production and consumption, regulations, and producer and consumer behavior. Projections are highly dependent on the data, methodologies, model structures, and assumptions used in their development. Behavioral characteristics 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 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 *AEO2009* 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.

AEO2009 Presents Three Views of Economic Growth

Figure 27. Average annual growth rates of real GDP, labor force, and productivity in three cases, 2007-2030 (percent per year)



AEO2009 presents three views of economic growth (Figure 27). The rate of growth in real gross domestic product (GDP) depends mainly on assumptions about labor force growth and productivity. In the reference case, growth in real GDP averages 2.5 percent per year from 2007 to 2030.

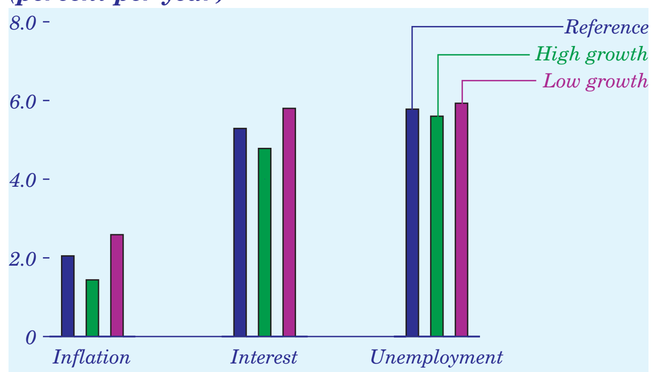
GDP growth is considerably slower in the near term as a result of the recent downturn in financial markets. In the *AEO2009* reference case, annual real GDP growth is negative in 2009 and does not start to recover until the fourth quarter of 2009.

The *AEO2009* high and low economic growth cases examine the impacts of alternative assumptions about the U.S. economy (see Appendix E for descriptions of all the alternative cases). The high economic growth case includes more rapid growth in the labor force, nonfarm employment, and productivity, resulting in real GDP growth of 3.0 percent per year. With higher productivity gains and employment growth, inflation and interest rates are lower than in the reference case.

In the low economic growth case, real GDP growth averages 1.8 percent per year from 2007 to 2030 as a result of slower growth in the labor force, nonfarm employment, and labor productivity. Consequently, the low growth case shows higher inflation, higher interest rates, and lower growth rates for industrial output and employment.

Inflation, Interest, and Jobless Rates Vary With Increases in Productivity

Figure 28. Average annual inflation, interest, and unemployment rates in three cases, 2007-2030 (percent per year)



In the *AEO2009* reference case, the average annual consumer price inflation rate is 2.1 percent, the annual yield on the 10-year Treasury note averages 5.3 percent, and the average unemployment rate is 5.8 percent (Figure 28). The higher inflation, interest, and unemployment rates in the low economic growth case and the lower rates in the high economic growth case depend on differences in assumptions about labor productivity and population growth.

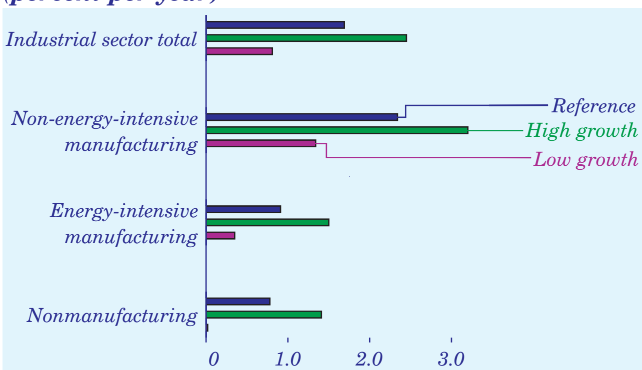
Over the first 5 years of the *AEO2009* reference case, inflation and interest rates are low, and unemployment rates rise as a result of the recession that began at the end of 2007. With the downturn affecting household wealth and economic output, unemployment remains high as people need more time to find employment. The unemployment rate does not fall back to its long-run average of 5.8 percent until 2015.

From 1982 to 2007, inflation averaged 3.1 percent per year, the average yield on 10-year Treasury notes was 7.1 percent per year, and the unemployment rate averaged 6.0 percent per year. In the *AEO2009* reference case, continuing gains in labor productivity and lower labor costs relative to historical averages lead to more optimistic projections for inflation, interest, and unemployment rates.

For U.S. consumers, energy prices in the reference case rise more rapidly than overall prices. For energy commodities, annual price increases average 3.0 percent per year from 2007 to 2030, and for energy services they average 2.3 percent per year.

Output Growth for Energy-Intensive Industries Is Expected To Slow

Figure 29. Sectoral composition of industrial output growth rates in three cases, 2007-2030 (percent per year)



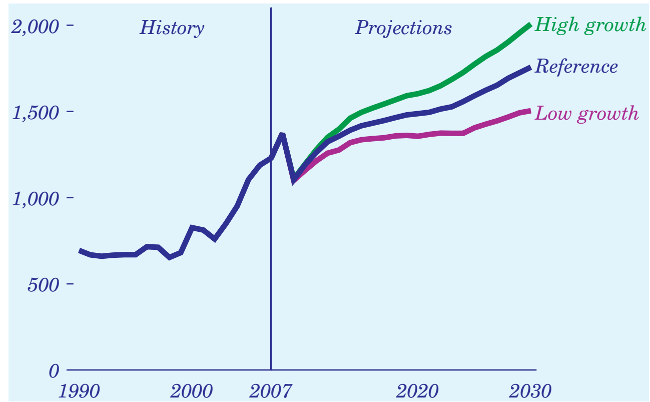
Industrial sector output has grown more slowly than the total economy in recent decades, as imports have met a growing share of demand for industrial goods. In the *AEO2009* reference case, real GDP grows at an annual average rate of 2.5 percent from 2007 to 2030, whereas the industrial sector grows by a slower 1.7 percent per year (Figure 29). Manufacturing output of goods grows more rapidly than nonmanufacturing output (which includes agriculture, mining, and construction). With higher energy prices and more foreign competition, the energy-intensive manufacturing sectors [*94*] grow at a slower overall rate of 0.9 percent per year, which includes a 0.4-percent annual decline for bulk chemicals and a 1.8-percent annual increase for food processing.

The construction, chemicals, primary metals, and transportation equipment industries grow slowly in the early years of the projection as the economy recovers from the current economic recession. After 2011, however, their output returns to its long-run growth path. Increased foreign competition, weak expansion of domestic production capacity, and higher energy prices mean more competitive pressure for most energy-intensive industries, particularly after 2015.

In the high economic growth case, output from the industrial sector grows by an annual average of 2.4 percent, still below the annual growth of real GDP (3.0 percent). In the low economic growth case, real GDP and industrial output grow by 1.8 and 0.8 percent per year, respectively. In both cases, the non-energy-intensive manufacturing industries show higher growth than the rest of the industrial sector.

Energy Expenditures Decline Relative to Gross Domestic Product

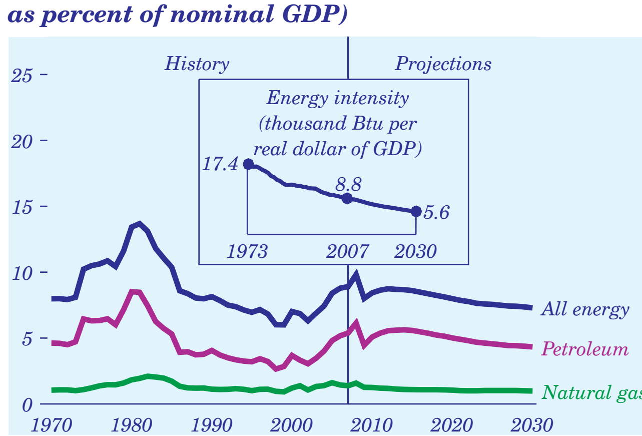
Figure 30. Energy expenditures in the U.S. economy in three cases, 1990-2030 (billion 2007 dollars)



Total expenditures for energy services in the U.S. economy were $1.2 trillion in 2007. Energy expenditures rise to $1.8 trillion (2007 dollars) in 2030 in the *AEO2009* reference case, $2.0 trillion in the high economic growth case, and $1.5 trillion in the low economic growth case (Figure 30). Energy intensity, measured as energy consumption (thousand Btu) per dollar of real GDP, was 8.8 in 2007 (Figure 31). With structural shifts in the economy, improvements in energy efficiency, and rising world oil prices, energy intensity declines to a ratio of 5.6 in 2030.

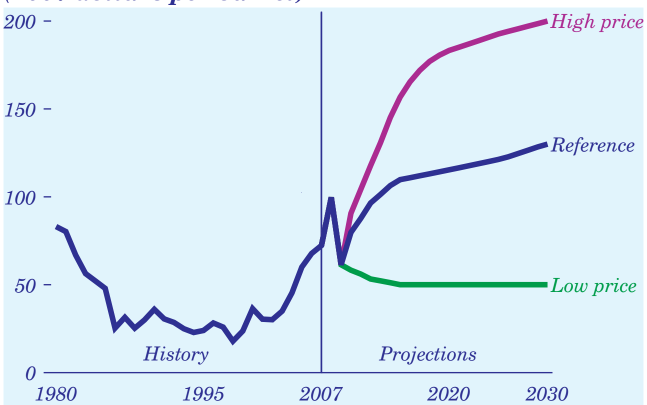
Since 2003, rising oil prices have pushed the nominal share of energy expenditures as a percent of GDP upward, and their 9.8-percent share in 2008 was the highest since 1986. In the reference case, as the energy efficiency of the economy improves, their share declines to 7.3 percent of GDP in 2030.

Figure 31. Energy expenditures as a share of gross domestic product, 1970-2030 (nominal expenditures as percent of nominal GDP)



Oil Price Cases Show Uncertainty in Prospects for World Oil Markets

Figure 32. World oil prices in three cases, 1980-2030 (2007 dollars per barrel)



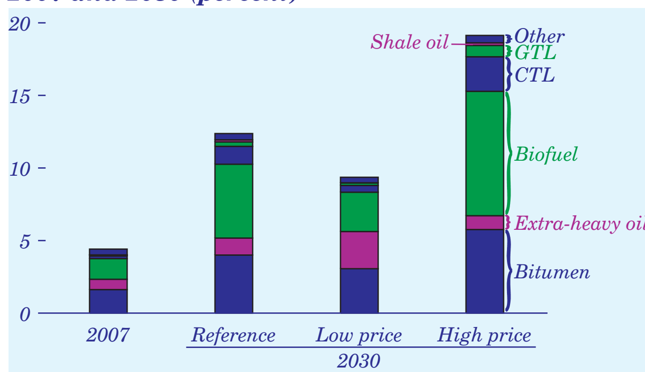
World oil price projections in *AEO2009*, defined in terms of the average price of imported low-sulfur, light crude oil to U.S. refiners, span a broad range that reflects the inherent uncertainty of world oil prices (Figure 32). The *AEO2009* low and high oil price paths are not intended to provide lower and upper bounds for future oil prices but rather to allow the analysis of possible future world oil market conditions that differ significantly from those assumed in the reference case. The long-term oil price paths are based on access to and cost of non-OPEC oil, OPEC supply decisions, and the supply potential of unconventional liquids, as well as the demand for liquids.

The high price case depicts a future world oil market in which conventional production is restricted by political decisions as well as by resource availability, as major producing countries use quotas, fiscal regimes, and various degrees of nationalization to increase their national revenues from oil production, and consuming countries turn to high-cost production of unconventional liquids to satisfy demand.

The low price case depicts a market in which non-OPEC producing countries develop stable fiscal policies and investment regulations directed at encouraging private-sector participation in the development of their resources. Although OPEC nations are not expected to change current investment restrictions significantly, the organization is expected to increase production in order to achieve an approximate 50-percent share of total world liquids production (119 million barrels per day) in 2030.

Unconventional Resources Gain Market Share as Prices Rise

Figure 33. Unconventional production as a share of total world liquids production in three cases, 2007 and 2030 (percent)



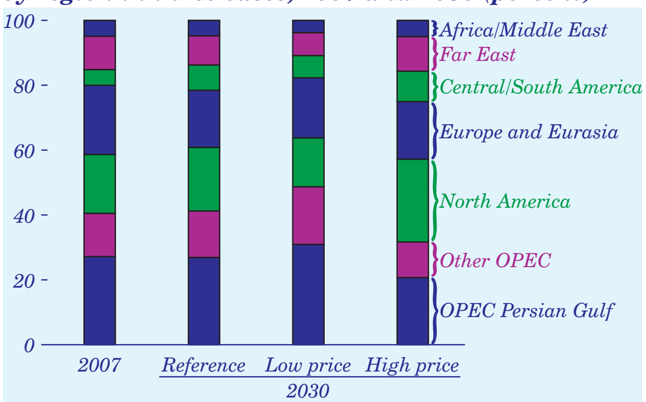
World production of liquid fuels from unconventional resources in 2007 was 3.6 million barrels per day, or about 4 percent of total liquids production. In the low oil price, reference, and high oil price cases, production from unconventional sources grows to between 11 million barrels per day and 17 million barrels per day, accounting for 9 percent to 19 percent of total liquids production, respectively, in 2030 (Figure 33).

Bitumen production from Canadian oil sands—by far the largest source of future unconventional liquids supply from any country—varies by about 1.5 million barrels per day across the three cases. The fiscal regime, extraction technologies, and relative profitability of projects associated with the Canadian bitumen are relatively constant, regardless of world oil prices. Production from Venezuela's extra-heavy oil resource depends on the market environment, not because of the oil price path but as a result of the levels of economic access to resources in the different cases. In the low price case, with more foreign investment, production in 2030 is more than double that in the reference case. In the reference and high price cases, with growing nationalization trends, production is limited to about 1 million barrels per day in 2030.

Production of biofuels, CTL, and GTL will be dictated largely by the needs of consuming nations—particularly, the United States and China, to compensate for restrictions on economic access to conventional liquid resources. In 2030, total production from those three sources ranges from 4.0 million barrels per day in the low price case to 10.4 million barrels per day in the high price case.

World Liquids Supply Is Projected To Remain Diversified in All Cases

Figure 34. World liquids production shares by region in three cases, 2007 and 2030 (percent)



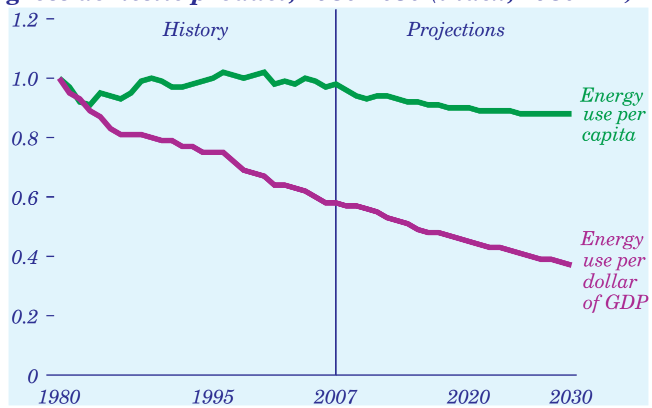
OPEC production decisions are the most significant factor underlying differences among the price cases. The *AEO2009* reference case assumes that OPEC will maintain a share of approximately 40 percent of total world liquids production through 2030, consistent with recent trends. In the high price case, OPEC reduces its market share to about 30 percent; in the low price case, OPEC's share grows to nearly 50 percent (Figure 34). In all the cases, total liquids production by countries in the Organization for Economic Cooperation and Development (OECD) is between 22 and 26 million barrels per day in 2030, constrained mainly by resource availability rather than price or political concerns.

In the high price case, several non-OPEC countries with large resource holdings (including Russia, Brazil, and Kazakhstan) either maintain or further restrict opportunities for investment in resource development, limiting their contributions to total liquids supply. Political, fiscal, and resource conditions in each of those countries are unique; however, all will require domestic and foreign investment to develop new projects and maintain infrastructure, and all have either resisted encouraging such investment or indicated that they might enact restrictions on foreign investment.

In the low price case, several resource-rich nations, including Russia and Venezuela, adopt new legislation or fiscal regimes in order to encourage foreign investment in the development of their resources. As a result, the largest increases in liquids production among the non-OPEC countries are in Kazakhstan, Russia, and Brazil.

Average Energy Use per Person Declines Through 2030

Figure 35. Energy use per capita and per dollar of gross domestic product, 1980-2030 (index, 1980 = 1)



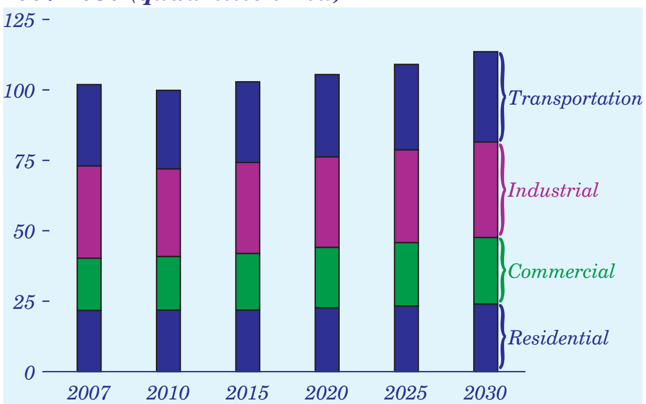
Growth in energy use is linked to population growth through increases in housing, commercial floorspace, transportation, manufacturing, and services. Since 1980, U.S. energy use per capita has remained relatively stable, between 310 and 360 million Btu per person. In periods of high energy prices (particularly, oil prices) energy consumption per capita has tended to be at the low end of the range, and in periods of low energy prices it has tended to move toward the high end. With the expectation that oil prices will remain high throughout the projection period, coupled with recent legislation enacted to increase energy efficiency, energy use per capita in the reference case drops below 310 million Btu in 2020 and continues a slow decline through 2030 (Figure 35).

Improvements in energy efficiency in response to higher CAFE standards and more stringent standards for lighting contribute to the decline in energy use per capita. Other contributing factors include moderate GDP growth and a decline in industrial energy use per dollar of output, as less energy-intensive industries provide a growing share of industrial production.

Energy intensity (energy use per 2000 dollar of GDP) also declines in all the end-use sectors in the reference case, as a result of both structural changes and efficiency improvements. The smallest decline from 2007 through 2030 is projected for the commercial sector, where recent energy legislation has only a small impact. In addition, growth in commercial floorspace outpaces housing growth.

Buildings and Transportation Sectors Lead Increases in Primary Energy Use

Figure 36. Primary energy use by end-use sector, 2007-2030 (quadrillion Btu)



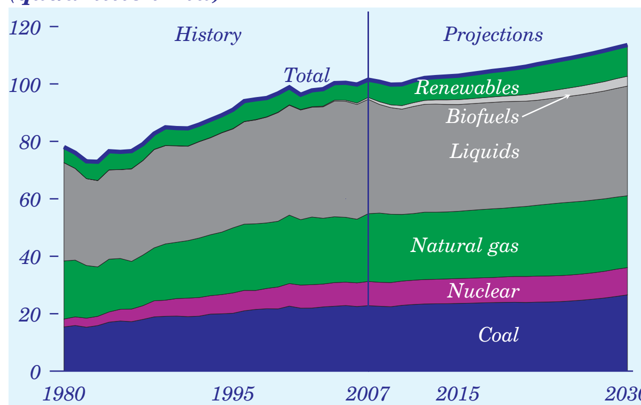
Total primary energy consumption, including for electricity generation, grows by 0.5 percent per year from 2007 to 2030 in the reference case (Figure 36). The fastest growth is projected for the commercial sector (1.1 percent), which has the smallest share of end-use energy demand. Growth in commercial energy use is led by increases for office equipment, ventilation, and “other uses,” including service station equipment, automated teller machines, telecommunications equipment, and medical equipment—most of which are powered by electricity. Residential energy use grows by 0.4 percent per year, with increases resulting from population growth, more personal computer use, and shifts to larger formats for television sets being offset in large part by efficiency improvements in lighting and appliances, as required by EISA2007.

Energy use for transportation also grows by 0.5 percent per year in the reference case. All growth in transportation energy consumption results from increased fuel use for freight trucks and air transportation. For LDVs, which make up the largest segment of energy use in the transportation sector, rising energy prices and enhanced CAFE standards offset increases in the number of vehicles sold and miles traveled.

Energy consumption in the industrial sector increases by only 0.1 percent per year. EISA2007 requires more use of biofuels in the transportation sector. Conversion of biomass to ethanol or diesel fuel in the industrial sector produces liquids with lower Btu content than the biomass feedstock, creating heat that can be used to power on-site equipment or to generate electricity for sale to the grid.

Renewable Sources Lead Rise in Primary Energy Consumption

Figure 37. Primary energy use by fuel, 1980-2030 (quadrillion Btu)



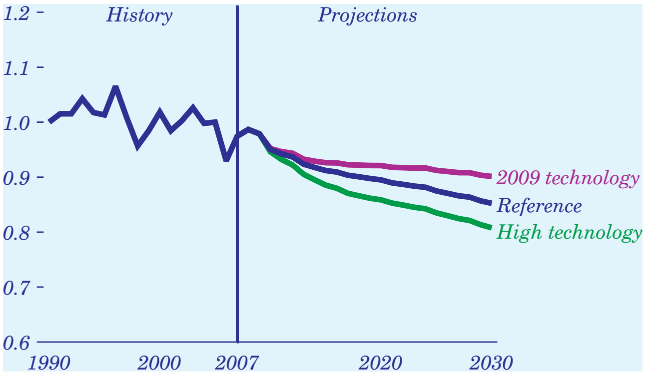
Primary energy consumption in the end-use sectors grows by 0.5 percent per year from 2007 to 2030, with annual demand for renewable fuels increasing the fastest—including E85 and biodiesel fuels for light-duty vehicles, biomass for co-firing at coal-fired electric power plants, and byproduct streams in the paper industry captured for energy production. Biomass consumption increases by 4.4 percent per year on average from 2007 to 2030 and makes up 22 percent of total marketed renewable energy consumption in 2030, compared with 10 percent in 2007.

The petroleum share of liquid fuel consumption in the transportation sector declines somewhat, as consumption of alternate fuels (such as biodiesel and E85) and blending components (such as ethanol) increases as a result of the RFS mandate in EISA2007. Overall, consumption of liquid fuels in the transportation sector—particularly for LDVs—continues to increase through 2030. After ethanol and biodiesel, the fastest growth in renewable energy consumption in the end-use sectors is projected for biomass use. In he mid-term (from 2014 to 2023), a decline in real output from the chemical industry leads to a reduction in demand for LPG and petrochemical feedstocks in the industrial sector.

Natural gas use increases by 0.2 percent per year over the projection period, including steady growth in the commercial sector, where it is used for on-site electricity generation. Coal consumption increases by 0.7 percent per year on average (Figure 37). Nearly all the increase results from the use of coal as a feedstock in the industrial sector, at new CTL plants.

Residential Energy Use per Capita Varies With Technology Assumptions

Figure 38. Residential delivered energy consumption per capita in three cases, 1990-2030 (index, 1990 = 1)

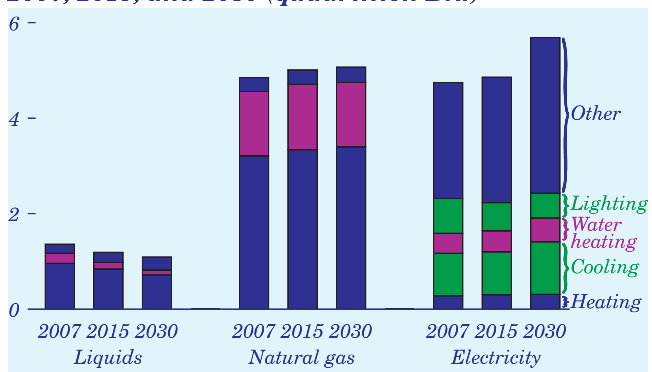


Over the past 10 years, the weather has generally been warmer than the 30-year average, causing residential energy use per person to remain mostly below its 1990 level. Increases in energy efficiency also have contributed to lower residential energy use, while consumer preference for larger homes and new energy-using technologies has worked in the opposite direction. Given the preponderance of warmer winters and summers, the *AEO2009* projections define normal weather as the average of the most recent 10 years of historical data, which decreases the need for heating fuels, such as natural gas and fuel oil, and increases the need for electricity used for air conditioning, all else being equal.

In the *AEO2009* projections, residential energy use per capita changes with assumptions about the rate at which more efficient technologies are adopted. The 2009 technology case assumes no increase in the efficiency of equipment or building shells beyond those available in 2009. The high technology case assumes lower costs, higher efficiencies, and earlier availability of some advanced equipment. In the reference case, residential energy use per capita is projected to fall below the 2006 level (the lowest since 1990) after 2012. In the 2009 technology case, delivered energy use per capita in the residential sector remains near the 2006 level through 2030, when it is 6 percent higher than projected in the reference case (Figure 38). In the high technology case, delivered energy use per capita in the residential sector falls below the 2006 level after 2011, reaching a 2030 level that is 5 percent below the reference case projection.

Household Use of Electricity Continues To Grow

Figure 39. Residential delivered energy consumption by fuel and service, 2007, 2015, and 2030 (quadrillion Btu)

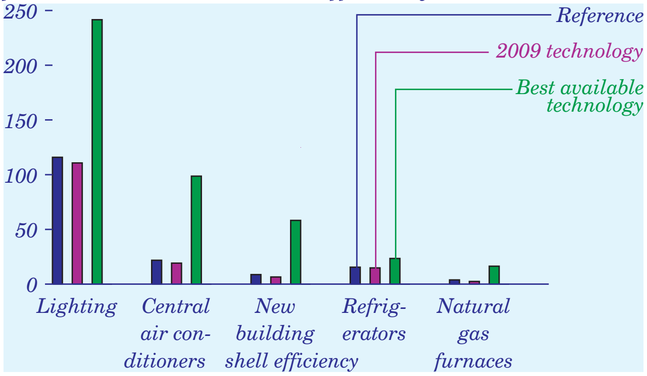


Residential electricity use has increased by 23 percent over the past decade, as efficiency improvements have been more than offset by increases in air conditioning use and the introduction of new applications. That trend continues in *AEO2009* (Figure 39). In 2030, electricity use for home cooling in the reference case is 24 percent higher than the 2007 level, as the U.S. population continues to migrate to the South and West, and older homes are converted from room air conditioning to central air conditioning. A projected 24-percent increase in the number of households also increases the demand for appliances, and total electricity use in the residential sector increases by 20 percent from 2007 to 2030 in the reference case. The share of electricity used for "other appliances" grows from 51 percent in 2007 to 58 percent in 2030, as home electronics continue to proliferate, and efficiency gains in traditional end uses (such as lighting) foster reductions in energy use per household.

Natural gas and liquid fuels are used in the residential sector primarily for space and water heating. Few new uses have emerged over the past decade, and few are expected in the future. Thus, natural gas and liquids consumption per household falls as the energy efficiency of furnaces and building components continues to improve. Demand for space and water heating per household declines by 19 percent from 2007 to 2030, as the population shifts from colder to warmer climates. Technologies that can reduce demand for natural gas in the residential sector include condensing gas furnaces, which can attain 95 percent efficiency, and tankless (instantaneous) water heaters, which can attain 80-percent efficiency, representing an increase of 36 percent over the current standard.

Increases in Energy Efficiency Are Projected To Continue

Figure 40. Efficiency gains for selected residential appliances in three cases, 2030 (percent change from 2007 installed stock efficiency)

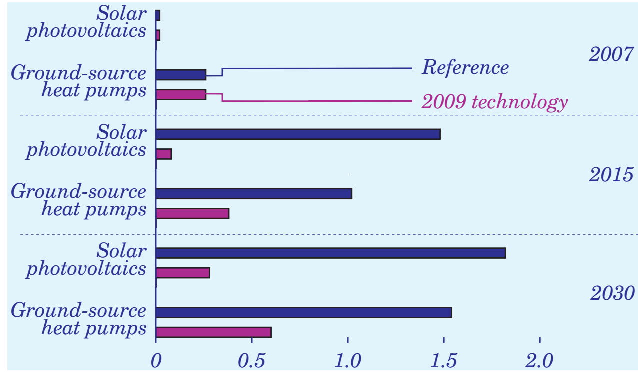


The energy efficiency of purchased equipment plays a key role in determining the types and amounts of energy used in residential buildings. Delivered energy use per household declines in the *AEO2009* reference case at an average annual rate of 0.6 percent, even as the average square footage of households rises and the penetration of appliances, especially electronics, continues to grow. Stock turnover and the resulting purchase of more efficient equipment account for most of the decline in residential energy intensity, while rising energy prices and more rapid growth of households in the Sunbelt regions together account for about one-third of the decline.

In the 2009 technology case, which assumes no efficiency improvement in available appliances beyond 2009 levels, normal stock turnover still results in higher average energy efficiency for most end uses in 2030, as older, less efficient appliances in the existing stock are replaced (Figure 40). The best available technology case assumes that consumers will install only the most efficient products available, regardless of cost, at normal replacement intervals, and that new buildings will meet the most energy-efficient specifications available. Because purchases of new energy-efficient products (including compact fluorescent bulbs, solid-state lighting, and condensing gas furnaces) cut energy use without reducing service levels, residential delivered energy consumption in 2030 is 29 percent lower in the best available technology than in the 2009 technology case and 25 percent lower than in the reference case. In the best available technology case, residential delivered energy intensity declines by 1.8 percent per year, and residential electricity use declines by almost 1 percent per year.

EIEA2008 Tax Credit Increases Installations of Efficient Equipment

Figure 41. Residential market penetration by renewable technologies in two cases, 2007, 2015, and 2030 (percent share of single-family homes)



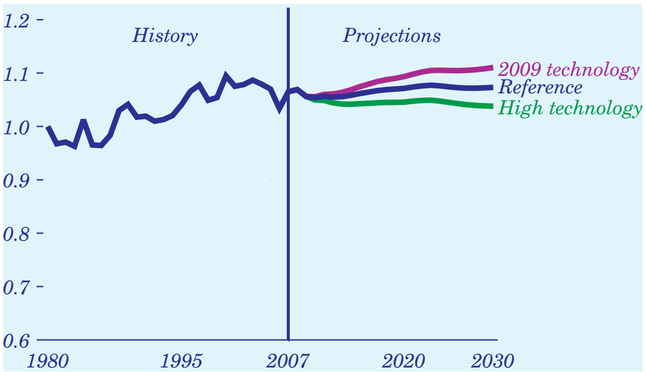
In the past, in a market dominated by such traditional energy resources as liquids, natural gas, and electricity, renewables have claimed only a tiny share of residential energy use. Wood-burning stoves and solar-powered water heaters are the most common renewable energy technologies used in households today; however, EIEA2008 provides sizable tax credits through 2016 for purchases of energy-efficient ground-source heat pumps and solar PV systems.

Ground-source heat pumps, which extract heat from the ground to provide energy for heating and cooling, are an efficient but relatively expensive alternative to traditional air-source heat pumps. Nationwide, roughly 35,000 ground-source heat pumps were installed in residential buildings in 2007. In the *AEO2009* reference case, which includes the $2,000 EIEA2008 tax credit for ground-source heat pumps, installations average 90,264 per year. As a result, their market share increases more than fivefold over their 2007 share, to 1.5 percent in 2030.

The outlook for solar PV installations is similar. Although residential solar PV has received a 30-percent Federal tax credit in the past few years, that credit was capped at $2,000. EIEA2008 removes the cap, allowing the average tax credit to reach roughly $10,000 for a 3.5-kilowatt system, thus enhancing the economics of residential installations considerably. Over the period of the tax credit (2009-2016), more than 1.6 million residential solar PV units are projected to be installed in the reference case (Figure 41).

Commercial Energy Use per Capita Is Projected To Level Off

Figure 42. Commercial delivered energy consumption per capita in three cases, 1980-2030 (index, 1980 = 1)

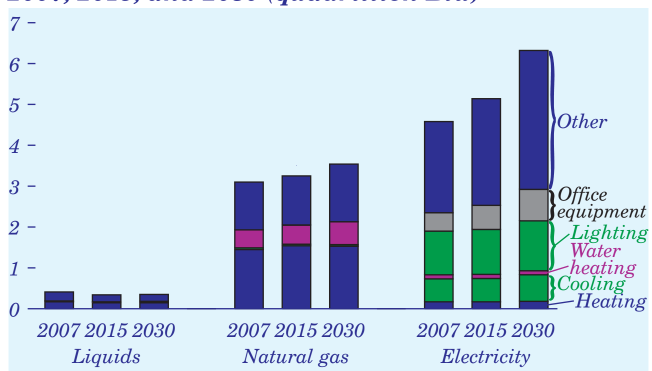


Assumptions about the availability and adoption of energy-efficient technologies help define the range for delivered commercial energy use per person in the *AEO2009* projections. Energy consumption per capita, which increased steadily in the 1980s and 1990s, stabilizes in the *AEO2009* reference case as efficiency improvements offset growth in demand for energy services (Figure 42). In the 2009 technology case, in which equipment and building shell efficiency improvements are limited to those available in 2009, commercial energy use per capita continues to increase through 2020 before leveling off. In the high technology case, which assumes earlier availability, lower costs, and higher efficiencies for more advanced equipment and building shells, future commercial energy use per capita remains below current levels, falling to 3.3 percent below the reference case level in 2030. Lower electricity use accounts for most of the difference from the reference case.

Growth in commercial floorspace averages 1.3 percent per year from 2007 to 2030 in the reference case, following trends in economic and population growth. The reference case assumes future improvements in efficiency for available equipment and building shells, as well as increased demand for services. The purchase of more efficient equipment in response to high energy prices offsets the increase in energy consumption that would have occurred with floorspace expansion, leading to a decline in commercial energy intensity in the *AEO2009* projections across all cases. The projected average annual declines in delivered energy intensity from 2007 to 2030 range from 0.1 percent per year in the 2009 technology case to 0.4 percent per year in the high technology case.

Electricity Leads Expected Growth in Commercial Energy Use

Figure 43. Commercial delivered energy consumption by fuel and service, 2007, 2015, and 2030 (quadrillion Btu)

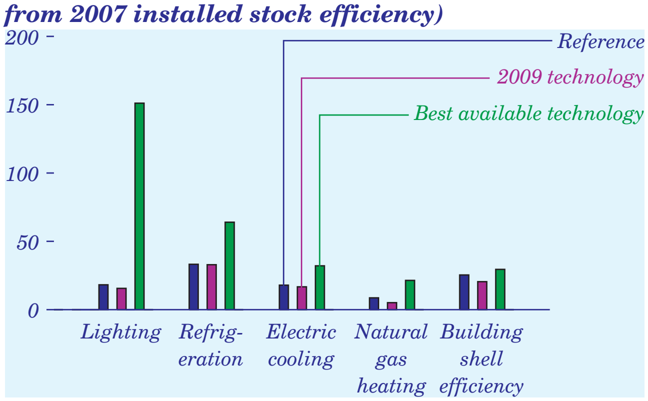


In the *AEO2009* reference case, growth in disposable income increases demand for services from hotels, restaurants, stores, theaters, and other commercial establishments, which increasingly depend on computers and other electronic office equipment for basic services and for business and customer transactions. The growing share of the population over age 65 also increases demand for health care and assisted-living facilities and for electricity to power medical and monitoring equipment at those facilities. In combination with "other" uses (such as telecommunications equipment), those increases offset improved efficiency in the major commercial end uses, so that total commercial electricity use increases by an average of 1.4 percent per year from 2007 to 2030.

Use of natural gas and liquids for heating shows limited growth (Figure 43), as commercial activity reflects the U.S. population shift to the South and West (where space heating requirements are relatively low) and the efficiency of building and equipment stocks improves. Commercial natural gas use grows by 0.6 percent per year on average from 2007 to 2030 in the reference case, including more use of CHP in the later years. Commercial natural gas use in 2030 varies slightly in response to changing economic assumptions, from 3.4 quadrillion Btu in the low growth case to 3.7 quadrillion Btu in the high growth case. Liquid fuels use shows little change over time in the reference case, as concerns about fuel costs and emissions make fuel oil less attractive for CHP. The high and low oil price cases show the widest range for liquid fuels use, from 8 percent below to 19 percent above the reference case projection of 0.6 quadrillion Btu in 2030, respectively.

Technology Provides Potential Energy Savings in the Commercial Sector

Figure 44. Efficiency gains for selected commercial equipment in three cases, 2030 (percent change from 2007 installed stock efficiency)



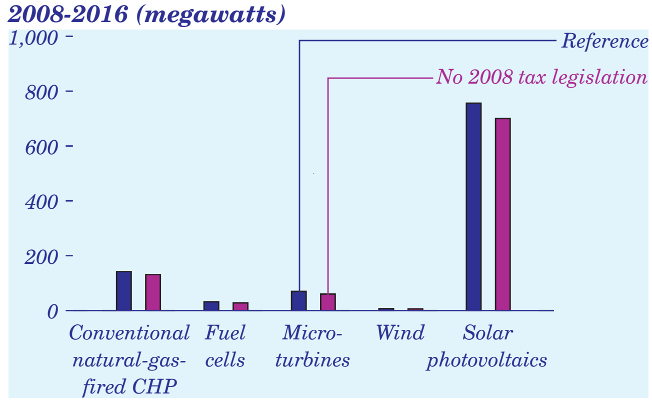
The stock efficiency of energy-consuming equipment in the commercial sector increases in the *AEO2009* reference case as equipment stocks age and are replaced by more energy-efficient technologies (Figure 44). As a result, commercial energy intensity falls by 0.3 percent per year. Stock turnover moderates the growth in energy use that otherwise would occur with a projected 1.3-percent average annual increase in commercial square footage. In addition, rising energy prices contribute about 0.1 percent per year to the decline in energy intensity.

The best available technology case assumes that only the most efficient technologies are chosen, regardless of cost, and that new building shells in 2030 are 29 percent more efficient than the 2007 stock. In the best available technology case, with the adoption of improved heat exchangers for space heating and cooling equipment, solid-state lighting, and more efficient compressors for commercial refrigeration, commercial delivered energy consumption in 2030 is 15 percent lower than in the reference case and 18 percent lower than in the 2009 technology case, and commercial delivered energy intensity declines by 1.0 percent per year from 2007 to 2030.

The 2009 technology case assumes that equipment and building shell efficiencies are limited to those available in 2009. In this case, energy efficiency in the commercial sector still improves from 2007 to 2030, but delivered energy intensity declines by only 0.1 percent per year, because the energy savings that otherwise would result from improving efficiency are offset primarily by increasing penetration of new electric appliances in the commercial sector.

Tax Credits, Advanced Technologies Could Boost Distributed Generation

Figure 45. Additions to electricity generation capacity in the commercial sector in two cases, 2008-2016 (megawatts)



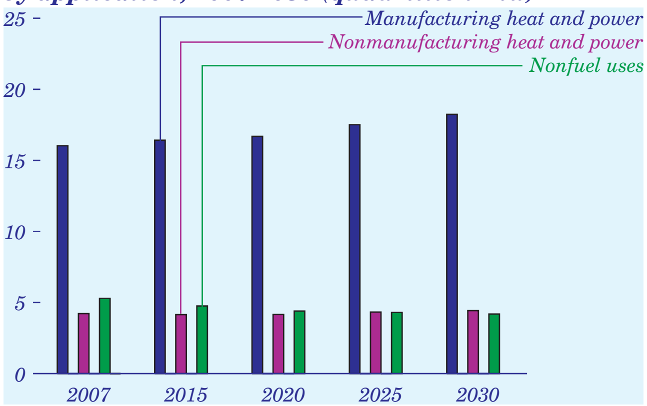
The extension and expansion of ITCs for distributed generation technologies in EIEA2008 result in a 3.2-percent increase in commercial sector electricity generation capacity by 2016 in the *AEO2009* reference case in comparison with the no 2008 tax legislation case. In the reference case, commercial solar PV installations show the largest increase, benefiting from a 30-percent business ITC with no cap on the allowable dollar amount. Conventional natural-gas-fired generating technologies, which are less capital-intensive than most renewable technologies, also receive a boost from the new 10-percent credit for CHP systems in the reference case (Figure 45).

In the high technology case, with more optimistic technology assumptions, electricity generation at commercial facilities in 2030 is 13 billion kilowatthours (37 percent) higher than in the reference case, and most of the increase offsets electricity purchases. In the best available technology case, 18 billion kilowatthours (55 percent) more commercial electricity generation (mostly from solar PV and wind systems) is projected for 2030 than in the reference case.

Some of the heat produced by fossil-fuel-fired generators in CHP applications can be used for water and space heating, increasing the efficiency and attractiveness of the technologies. On the other hand, the additional natural gas used for CHP systems in the commercial sector raises total natural gas consumption in the reference case and offsets some of the reductions in energy costs that result from efficiency gains in end-use equipment and building shells in the high technology and best technology cases.

Manufacturing Takes a Growing Share of Total Industrial Energy Use

Figure 46. Industrial delivered energy consumption by application, 2007-2030 (quadrillion Btu)



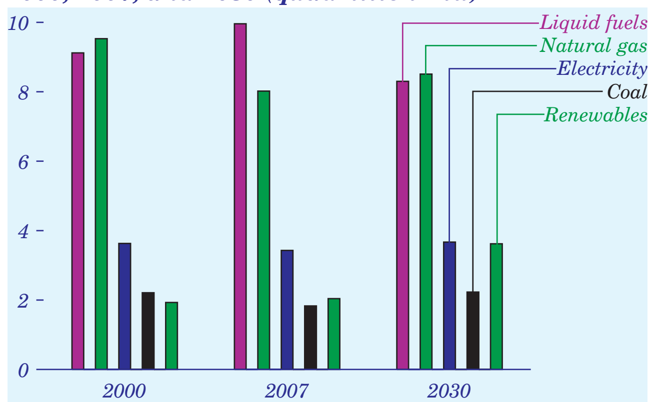
About two-thirds of delivered energy consumption in the industrial sector is used for heat and power in manufacturing. Nonfuel uses of energy fuels, primarily as feedstocks in chemical manufacturing and asphalt for construction, make up one-fifth of the total, and nearly all the rest is used for heat and power in agriculture, mining, and construction. In the reference case, despite a 47-percent increase in industrial shipments, industrial delivered energy consumption grows by only 4 percent from 2007 to 2030, mainly as a result of slow growth or declines in output from most of the energy-intensive manufacturing industries. In the chemical industry, in particular, shipments decline by 10 percent from 2007 to 2030.

Manufacturing energy use for heat and power grows through 2030, with large increases in refining and biofuel production more than offsetting reductions in output for bulk chemicals, iron and steel, and aluminum. In contrast, despite projected recovery in the construction industry, with 23-percent output growth from 2007 to 2030, nonmanufacturing energy use in 2030 is approximately the same as in 2007. Efficiency improvements in diesel- and gasoline-powered construction equipment slow the growth of energy consumption in the nonmanufacturing industries.

Prospects for nonfuel uses of energy depend on output trends in the chemical, agriculture, and construction industries, as well as the potential for synthetic fuel production, including CTL and GTL. In the reference case, efficiency improvements, a shrinking chemical industry, and unfavorable prospects for CTL and GTL contribute to a 21-percent reduction in nonfuel uses of energy from 2007 to 2030 (Figure 46).

Industrial Fuel Choices Vary Over Time

Figure 47. Industrial energy consumption by fuel, 2000, 2007, and 2030 (quadrillion Btu)



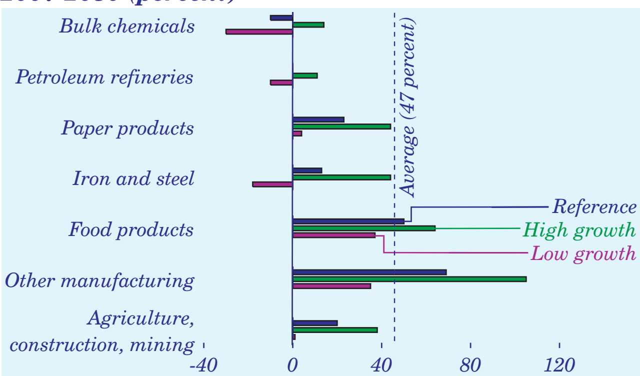
Liquid fuels and natural gas account for 71 percent of industrial delivered energy consumption, with electricity, coal, and renewables accounting for the rest. Because fuel-switching opportunities in existing plants are limited, changes in fuel shares tend to reflect long-term transitions in the mix of industries, as well as impacts of capital investment. In the reference case, natural gas is the leading industrial fuel source in 2030, as opposed to liquid fuels in 2007 (Figure 47). Even so, natural gas use in 2030 remains below its 2000 level. Growth in natural gas use is moderated by a decline in consumption in the chemical industry, which accounted for about one third of total industrial natural gas use in 2007 (excluding natural gas lease and plant fuel). About three-fourths of liquid fuel consumption in the industrial sector is for nonfuel uses or is generated as a byproduct in refining.

Coal use for CTL production more than offsets a decline in such traditional applications as steam generation and coke production as a result of environmental concerns related to emissions from coal-fired boilers, along with manufacturing efficiency improvements that reduce the need for process steam. Metallurgical coal use also declines, reflecting modest growth in the steel industry and the spread of electric arc furnaces.

Modest growth in industrial electricity use reflects efficiency improvements across a wide spectrum of industries, attributable in part to the new motor efficiency standards included in EISA2007. Renewable energy consumption in the industrial sector expands with the projected growth in pulp and paper shipments, which allows more biomass to be recovered from those production processes.

Energy-Intensive Industries Grow Less Rapidly Than Industrial Average

Figure 48. Cumulative growth in value of shipments for industrial subsectors in three cases, 2007-2030 (percent)



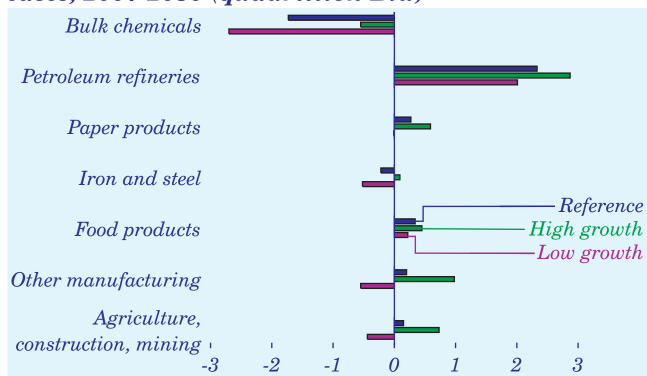
Industrial activity varies across the *AEO2009* economic growth cases, reflecting uncertainty about growth in the economy. Total industrial shipments grow by 47 percent from 2007 to 2030 in the reference case, as compared with 20 percent in the low economic growth case and 74 percent in the high economic growth case. In the near term, however, industrial activity is slowed by the current economic downturn. From 2007 to 2010, shipments decline for many industries (including construction, bulk chemicals, refining, steel, cement, and paper products), and industrial delivered energy use in the reference case falls by about 6 percent before recovering.

A few energy-intensive industries account for a large share of total industrial energy consumption. Ranked by 2007 energy consumption, the top five energy-consuming industries—bulk chemicals, refining, paper, steel, and food—accounted for about 60 percent of total industrial energy use but only 20 percent of total shipments. Those five and the other energy-intensive industries (glass, cement, and aluminum) grow more slowly than the non-energy-intensive industries (Figure 48).

The relatively slow growth of energy-intensive manufacturing industries in the reference case results from increased foreign competition, reduced domestic demand for the raw materials and basic goods they produce, and movement of investment capital to more profitable areas. In general, a shift in manufacturing from basic goods toward less energy-intensive, higher-value products results from the comparative advantage of the technically advanced U.S. economy in international trade.

Energy Consumption Growth Varies Widely Across Industry Sectors

Figure 49. Cumulative growth in delivered energy consumption for industrial subsectors in three cases, 2007-2030 (quadrillion Btu)

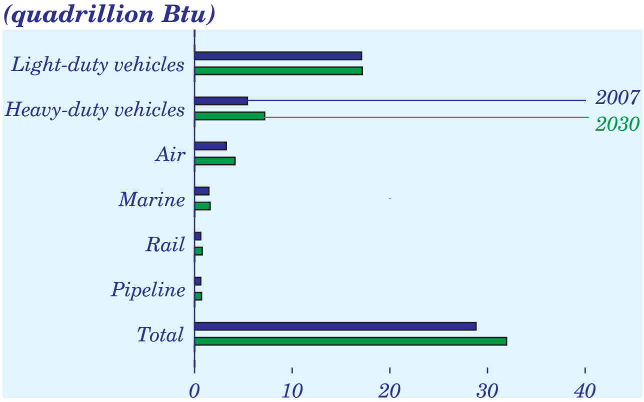


The projections for industrial energy consumption vary by industry and are subject to considerable uncertainty, as reflected in the three economic growth cases (Figure 49). Industrial delivered energy consumption grows by 4 percent from 2007 to 2030 in the reference case, declines by 9 percent in the low economic growth case, and increases by 19 percent in the high economic growth case. In absolute terms, the most significant changes in energy consumption from 2007 to 2030 are in the two largest energy-consuming industries, bulk chemicals and refining. The decline in energy use for bulk chemicals, a major exporting industry, reflects increased competition in foreign markets from countries with access to less expensive energy sources, combined with improvements in energy efficiency. Energy consumption in the refining industry increases—despite a relatively flat trend in overall petroleum demand—given the industry's needs to process heavier crudes, comply with low-sulfur fuel standards, and produce biofuels as mandated in EISA2007.

For the cement and steel industries, delivered energy consumption declines from 2007 to 2030, primarily as a result of relatively slow output growth, expected long-term changes in production technology, and rising energy prices after 2020. Energy use increases in the paper and pulp industry, with rising shipments reversing recent declines, and in the food industry. The decline in aggregate industrial energy intensity, or consumption per real dollar of shipments, is more rapid when a higher rate of economic growth is assumed: 1.7 percent in the high economic growth case, as compared with 1.5 percent in the reference case and 1.2 percent per year in the low growth case.

Growth in Transportation Energy Use Is Expected To Be Slow

Figure 50. Delivered energy consumption for transportation by mode, 2007 and 2030 (quadrillion Btu)



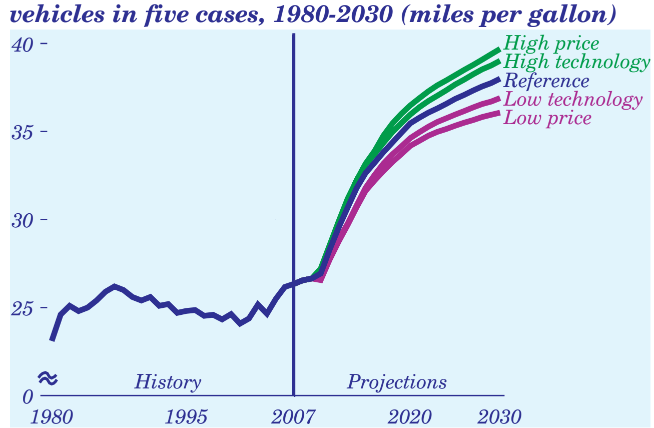
From 2007 to 2030, total delivered energy consumption in the transportation sector grows at an average annual rate of 0.4 percent, from 28.8 quadrillion Btu in 2007 to 31.9 quadrillion Btu in 2030, as compared with the 1.5-percent average rate from 1980 to 2007. Energy use by LDVs levels off in the reference case because of higher energy prices and more stringent CAFE standards, and because growth in demand for air travel also is expected to be slower than in the past.

Energy demand for LDVs (cars, pickup trucks, sport utility vehicles, and vans) increases by just 0.08 quadrillion Btu from 2007 to 2030 (Figure 50), with annual increases in vehicle-miles traveled offset by fuel economy gains resulting from rapidly increasing fuel economy requirements in the near term. Slower growth in income per capita and higher fuel costs also reduce the growth of personal travel, slowing the growth in demand for both highway and aviation fuels. Increases in the fuel efficiency of aircraft also reduce consumption of jet fuel.

More rapid increases in energy demand are projected for other transportation modes. Heavy-duty vehicles (including freight trucks and passenger buses) lead the growth in transportation energy demand over the projection, as a result of their smaller gains in fuel efficiency and expected increases in industrial output. For marine and rail transportation, increases in energy consumption result from the growth of industrial output and growing demand for coal transport. Pipeline energy consumption also increases with the projected growth in volumes of petroleum and natural gas transported.

New CAFE Standards Improve Light-Duty Vehicle Fuel Efficiency

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



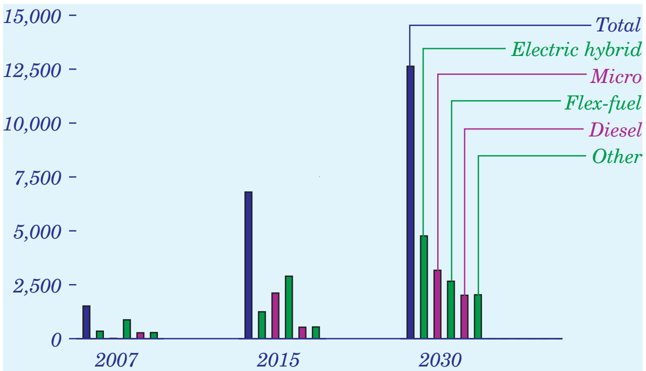
Light trucks (pickups, sport utility vehicles, and vans) have made up a steadily growing share of U.S. LDV sales in recent years [*95*]. Thus, despite technology improvements, the average fuel economy of new LDVs declined from 26.2 mpg in 1987 to a range between 24 and 26 mpg from 1995 to 2006 (Figure 51).

NHTSA has proposed a new attribute-based CAFE standard under which LDV fuel economy would increase rapidly through 2015 and at a slower rate through 2020. Accordingly, in the *AEO2009* reference case, the fuel economy of new LDVs increases by an average of 3.6 percent per year from 2011 to 2015, from 28 mpg to 33 mpg, and by 1.6 percent on average from 2016 to 2020, to 35.5 mpg, slightly exceeding the EISA2007 requirement of 35 mpg in 2020.

In all the *AEO2009* cases, LDV sales in 2030 total about 20 million units; however, the mix of cars and light trucks sold varies across the cases. In the reference case, cars represent 64 percent of total sales in 2030, and LDV fuel economy averages 38.0 mpg. In the high oil price case, cars make up 69 percent of sales in 2030, and LDV fuel economy averages 39.7 mpg. In the low oil price case, cars make up 53 percent of total sales in 2030, and LDV fuel economy averages 36.1 mpg. The economics of fuel-saving technologies improve further in the high technology and high price cases, and consumers buy more fuel-efficient cars and trucks; however, average fuel economy improves only modestly, because the proposed new NHTSA CAFE standards already require significant penetration of advanced technologies, pushing fuel economy improvements to the limit of the technologies included in the model.

Unconventional Vehicle Technologies Exceed 63 Percent of Sales in 2030

Figure 52. Sales of unconventional light-duty vehicles by fuel type, 2007, 2015, and 2030 (thousand vehicles sold)



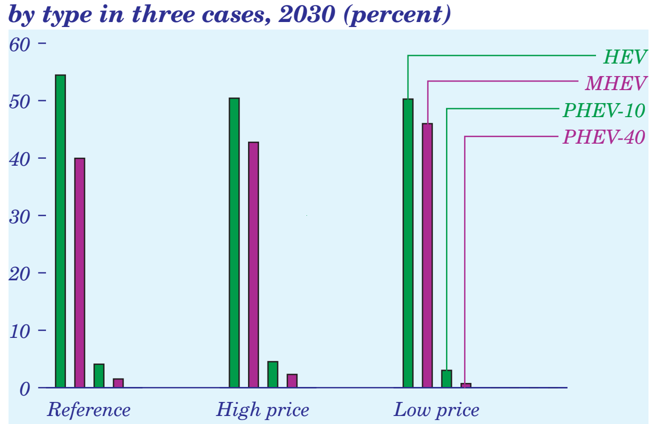
Concerns about oil supply, fuel prices, and emissions have driven the market penetration of unconventional vehicles (vehicles that can use alternative fuels, electric motors and advanced electricity storage, advanced engine controls, or other new technologies). Unconventional vehicle technologies are expected to play a greater role in meeting the new NHTSA CAFE standards for LDVs. Unconventional vehicles account for 63 percent of total new LDV sales in 2030 in the *AEO2009* reference case.

Hybrid vehicles (including both standard hybrids and PHEVs) represent the largest share of the unconventional LDV market in 2030 (Figure 52), at 63 percent of all new unconventional LDV sales and 40 percent of all new LDV sales. Micro hybrids, which allow the vehicle's gasoline engine to turn off by switching to battery power when the vehicle is idling, have the second-largest share, at 25 percent of unconventional LDV sales. Turbo diesel direct injection engines, which can improve fuel economy significantly, capture a 16-percent share of unconventional LDV sales. The availability of ultra-low-sulfur diesel and biodiesel fuels, along with advances in emission control technologies that reduce criteria pollutants, supports the increase in diesel LDV sales.

Currently, manufacturers receive incentives for selling FFVs, through fuel economy credits that count toward CAFE compliance. Although those credits are assumed to be phased out by 2020, FFVs make up 13 percent of all new LDV sales in 2030 in the reference case, in part because of the increased availability and lower cost of E85.

Hybrid Vehicle Shares in 2030 Vary With Fuel Price Assumptions

Figure 53. Sales shares of hybrid light-duty vehicles by type in three cases, 2030 (percent)



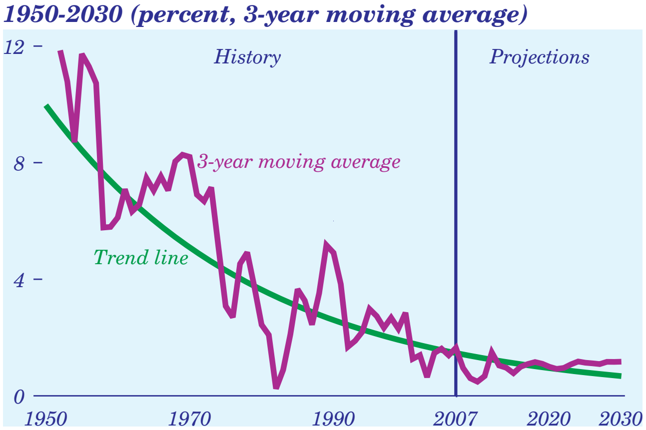
With more stringent CAFE standards and higher fuel prices, unconventional vehicles account for the majority of new LDV sales in 2030 in the reference case, and hybrid electric vehicles claim the largest share of unconventional vehicle sales. Four types of hybrid vehicle are expected to be available for sale in 2030: standard gasoline-electric hybrid (HEV), plug-in hybrid with an all-electric range of 10 miles (PHEV-10), plug-in hybrid with an all-electric range of 40 miles (PHEV-40), and micro hybrid (MHEV).

In the reference case, total hybrid sales increase from 2.3 percent of new LDV sales in 2007 to 20.6 percent in 2015 and 39.6 percent (7.9 million vehicles) in 2030. In the high oil price case, hybrids make up 45.3 percent of new LDV sales in 2030, with sales of 9.1 million; in the low oil price case, they make up 37.8 percent, with sales of 7.6 million.

In the high price case, the mix of hybrid vehicle types sold in 2030 shifts to more fuel-efficient PHEVs: PHEV-10 sales increase from 1.6 percent of LDV sales in the reference case to 2.0 percent in the high price case, and PHEV-40 sales increase from 0.6 percent to 1.0 percent of LDV sales. In the low price case, consumers have less incentive to buy the most efficient (and expensive) PHEVs. Accordingly, vehicle manufacturers increase production of less expensive MHEVs, which claim a larger share of hybrid vehicle sales than they do in the high price case (Figure 53).

Rate of Electricity Demand Growth Slows, Following the Historical Trend

Figure 54. U.S. electricity demand growth, 1950-2030 (percent, 3-year moving average)



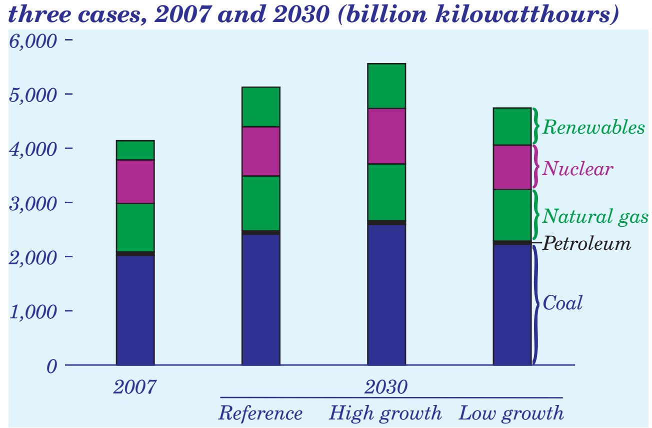
Electricity demand fluctuates in the short term in response to business cycles, weather conditions, and prices. Over the long term, however, electricity demand growth has slowed progressively by decade since 1950, from 9 percent per year in the 1950s to less than 2.5 percent per year in the 1990s. From 2000 to 2007, increases in electricity demand averaged 1.1 percent per year. The slowdown in demand growth is projected to continue over the next 23 years (Figure 54), as a result of efficiency gains in response to rising energy prices and new efficiency standards for lighting, heating and cooling, and other appliances.

In the reference case, electricity demand increases by 26 percent from 2007 to 2030, or by an average of 1.0 percent per year. The largest increase is in the commercial sector (38 percent), where service industries continue to lead demand growth, followed by the residential sector (20 percent) and the industrial sector (7 percent). Population growth and rising disposable incomes increase the demand for products, services, and floorspace, and ongoing population shifts to warmer regions increase the use of electricity for space cooling.

From 2007 levels, electricity demand increases by 36 percent in the high growth case, to 5,323 billion kilowatthours in 2030, compared with an increase of 16 percent in the low growth case, to 4,518 billion kilowatthours in 2030. Plug-in electric hybrid vehicles are not expected to reverse the trend of slowing growth in electricity demand, which increases by only 0.1 percent for every 1 million PHEV-40 vehicles in operation.

Coal-Fired Power Plants Provide Largest Share of Electricity Supply

Figure 55. Electricity generation by fuel in three cases, 2007 and 2030 (billion kilowatthours)



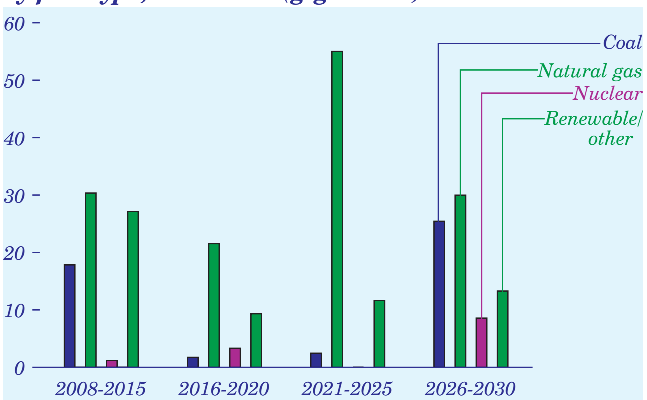
Coal continues to provide the largest share of energy for U.S. electricity generation in the *AEO2009* reference case, with only a modest decrease from 49 percent in 2007 to 47 percent in 2030. Total electricity generation at coal-fired power plants in 2030 is 19 percent higher than the 2007 total (Figure 55). Growth in coal-fired generating capacity is limited by concerns about GHG emissions and the potential for mandated limits, but existing plants continue to be used intensively.

Concerns about GHG emissions have little effect on construction of new capacity fueled by natural gas. The natural gas share of generation increases to 21 percent in 2027, before dropping to 20 percent in 2030, about the same as in 2007. Generation from nuclear power increases by 13 percent from 2007 to 2030, as addition of new units and uprates at existing units increase overall capacity and generation. The nuclear share of total generation falls somewhat, however, from 19 percent in 2007 to 18 percent in 2030. Renewable generation, supported by Federal tax incentives and State renewable programs, increases by more than 100 percent from 2007 to 2030, when it accounts for 14 percent of total generation.

Projected growth in demand for electricity varies with different assumptions about future economic conditions. In 2030, total generation in the high economic growth case is 9 percent above the reference case projection, and in the low economic growth case it is 7 percent below the reference case.

Most New Capacity Uses Natural Gas as Fewer Coal-Fired Plants Are Added

Figure 56. Electricity generation capacity additions by fuel type, 2008-2030 (gigawatts)



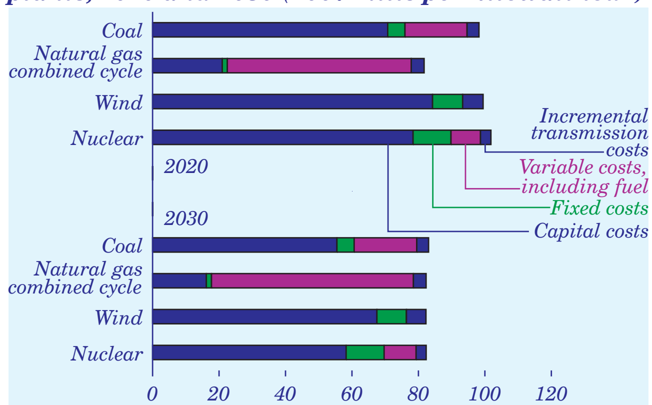
Decisions to add capacity and the choice of fuel type depend on electricity demand growth, the need to replace inefficient plants, the costs and operating efficiencies of different options, fuel prices, and the availability of Federal tax credits for some technologies. With growing electricity demand and the retirement of 30 gigawatts of existing capacity, 259 gigawatts of new generating capacity (including end-use CHP) will be needed between 2007 and 2030.

Natural-gas-fired plants account for 53 percent of capacity additions in the reference case, as compared with 22 percent for renewables, 18 percent for coal-fired plants, and 5 percent for nuclear (Figure 56). Escalating construction costs have the largest impact on capital-intensive technologies, including renewables, coal, and nuclear; but Federal tax incentives, State energy programs, and rising prices for fossil fuels increase the cost-competitiveness of renewable and nuclear capacity. In contrast, uncertainty about future limits on GHG emissions and other possible environmental regulations (reflected in the *AEO2009* reference case by adding 3 percentage points to the cost of capital for new coal-fired capacity) reduces the competitiveness of coal.

Projected capacity additions also are affected by demand growth and by fuel prices. Reflecting slower and faster growth in demand for electricity, capacity additions from 2007 to 2030 total 184 gigawatts and 350 gigawatts in the low and high economic growth cases, respectively. The higher fuel costs in the *AEO-2009* high oil price case lead to fewer additions of natural-gas-fired plants, because fuel costs make up a relatively large share of their total expenditures.

Least Expensive Technology Options Are Likely Choices for New Capacity

Figure 57. Levelized electricity costs for new power plants, 2020 and 2030 (2007 mills per kilowatthour)



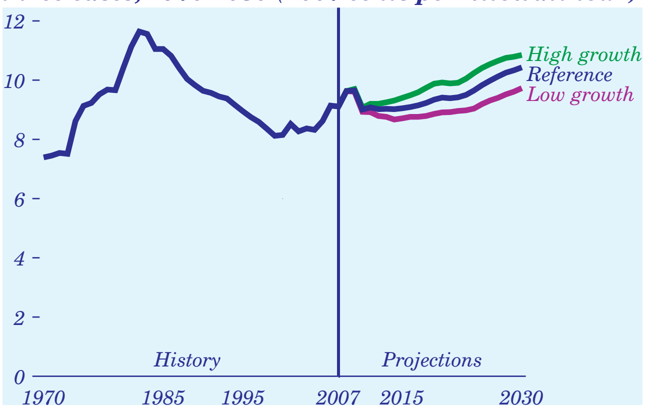
Technology choices for new generating capacity are made to minimize costs while meeting local and Federal emissions constraints. Capacity expansion decisions consider capital, operating, and transmission costs. Typically, coal-fired, nuclear, and renewable plants are capital-intensive, whereas operating (fuel) expenditures account for most of the costs associated with natural-gas-fired capacity (Figure 57) [*96*]. Capital costs depend on such factors as interest rates and cost-recovery periods. Fuel costs can vary according to plant operating efficiency, resource availability, and transportation costs.

Regulatory uncertainty affects capacity planning decisions. Unless they are equipped with CCS equipment, new coal-fired plants could incur higher costs as a result of higher expenses for siting and permitting. Because nuclear and renewable power plants (including wind plants) do not emit GHGs, however, their costs are not directly affected by regulatory uncertainty.

Capital costs can decline over time as developers gain experience with a given technology. In the *AEO2009* reference case, capital costs are adjusted upward initially, to reflect the optimism inherent in early public estimates of project costs. The costs decline as project developers gain experience, and the decline continues at a progressively slower rate as more units are built. Operating efficiencies also are assumed to improve over time, and variable costs could therefore be reduced unless increases in fuel costs exceed the savings from efficiency gains.

Electricity Prices Moderate in the Near Term, Then Rise Gradually

Figure 58. Average U.S. retail electricity prices in three cases, 1970-2030 (2007 cents per kilowatthour)



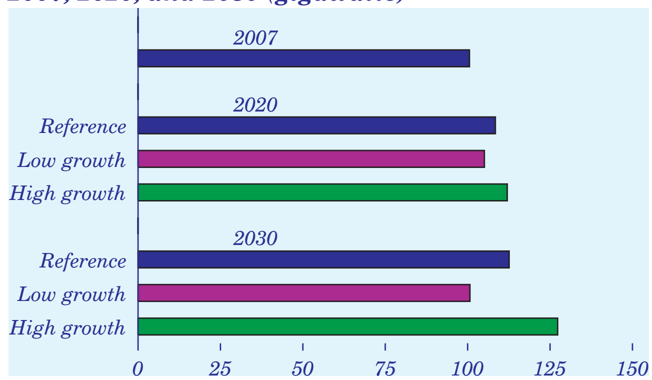
In recent years, real electricity prices (in 2007 dollars) have increased sharply, as fuel costs and capital costs have risen rapidly and restructuring initiatives that constrained price increases have ended. In the *AEO2009* reference case, real electricity prices fall in the near term when fuel prices decline during the economic slowdown. With economic recovery, real electricity prices stabilize at 9.0 cents per kilowatthour in 2010, then remain at that level for several years, while fuel prices remain relatively low and new coal- and natural-gas-fired capacity comes on line. Real electricity prices begin to rise steadily after 2015, as fuel prices increase more rapidly and the need for new capacity grows. Much of the new renewable capacity is required by State renewable mandates.

Real retail electricity prices increase to 10.4 cents per kilowatthour in 2030 in the reference case (Figure 58). They are higher in the high economic growth case, reaching 10.8 cents per kilowatthour in 2030 as stronger economic growth leads to more rapid growth in electricity demand. Electricity prices are lower in the low economic growth case, at 9.7 cents per kilowatthour in 2030.

Transmission costs, while remaining a relatively small component of delivered electricity prices, increase by 35 percent from 2007 to 2030 because of the additional investment needed to meet electricity demand growth, alleviate existing transmission constraints and bottlenecks, facilitate the operation of competitive wholesale energy markets, and link new generation from remote wind facilities with demand centers.

EPACT2005 Tax Credits Are Expected To Stimulate Some Nuclear Builds

Figure 59. Electricity generating capacity at U.S. nuclear power plants in three cases, 2007, 2020, and 2030 (gigawatts)

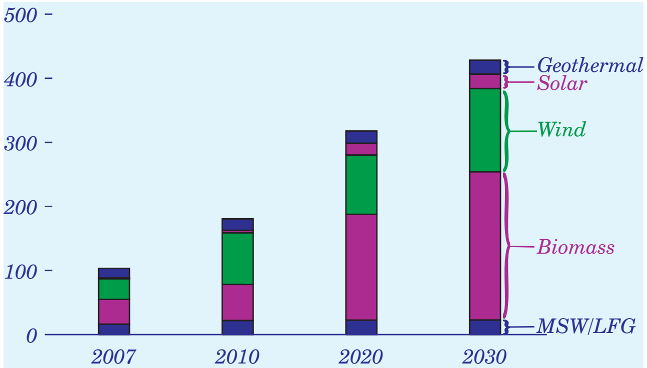


In the *AEO2009* reference case, nuclear power capacity increases from 100.5 gigawatts in 2007 to 112.6 gigawatts in 2030, including 3.4 gigawatts of expansion at existing plants, 13.1 gigawatts of new capacity, and 4.4 gigawatts of retirements. The reference case includes a second unit in 2014 at the Watts Bar site, where construction was halted in 1988 after being partially completed. Rising costs for construction materials have greatly increased the estimated cost of new nuclear plants, which when combined with the current instability of financial markets makes new investments in nuclear power uncertain. In the reference case, some 10 new nuclear power plants are completed through 2030. The first few are eligible for the EPACT2005 PTC. Most existing nuclear units continue to operate through 2030, based on the assumption that they will apply for and receive operating license renewals. Seven units, totaling 4.4 gigawatts, are retired after 2028, when they reach the end date of their original licenses plus a 20-year renewal.

In the *AEO2009* projections, nuclear capacity additions vary with assumptions about overall demand for electricity and the prices of other fuels (Figure 59). The amount of nuclear capacity added also is sensitive to assumptions about future plans and policies for limiting or reducing GHG emissions. Across the oil price and economic growth cases, nuclear capacity additions from 2007 to 2030 range from 1 to 28 gigawatts. In the low economic growth case, with falling electricity demand and rising interest rates, new nuclear plants are not economical. More new nuclear capacity is built in the high growth and high oil price cases, because overall capacity requirements are higher and/or alternatives are more expensive.

Biomass and Wind Lead Projected Growth in Renewable Generation

Figure 60. Nonhydroelectric renewable electricity generation by energy source, 2007-2030 (billion kilowatthours)

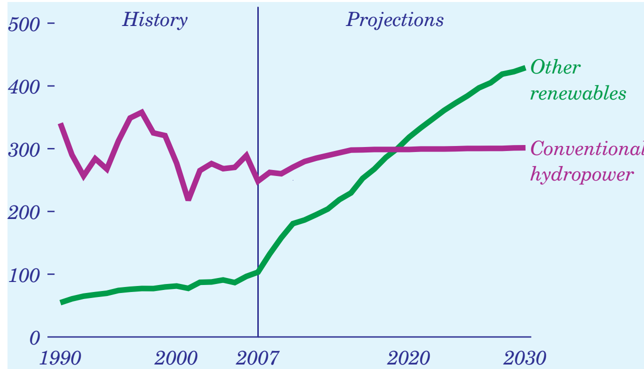


The potential for growth in electricity generation from wind power depends on a variety of factors, including fossil fuel costs, State renewable energy programs, technology improvements, access to transmission grids, public concerns about environmental and other impacts, and the future of the Federal PTC for wind, which is scheduled to expire at the end of 2009. Other renewable technologies are guaranteed a tax credit for an additional year. In the *AEO2009* reference case, generation from wind power increases from 0.8 percent of total generation in 2007 to 2.5 percent in 2030 (Figure 60). Generation from biomass, both dedicated and co-firing, grows from 39 billion kilowatthours in 2007 (0.9 percent of the total) to 231 billion kilowatthours (4.5 percent) in 2030. Generation from geothermal facilities also increases but at such a slow rate that it does not gain market share. Current assessments show limited potential for expansion at conventional geothermal sites. Enhanced geothermal development remains economically infeasible.

The principal reason for the robust growth of renewable electricity generation in the end-use sectors, which is included in the totals above, is the EISA2007 renewable fuels mandate. Biorefineries producing cellulosic ethanol use residues from the biomass feedstock for electricity production. Generation from biomass comprises nearly 80 percent, or 91 billion kilowatthours, of end-use renewable electricity in 2030. Solar technologies in general remain too costly for grid-connected applications, but demonstration programs and State policies support some growth in central-station solar PV, and small-scale, customer-sited PV applications grow rapidly [*97*].

Technology Advances, Tax Provisions Increase Renewable Generation

Figure 61. Grid-connected electricity generation from renewable energy sources, 1990-2030 (billion kilowatthours)

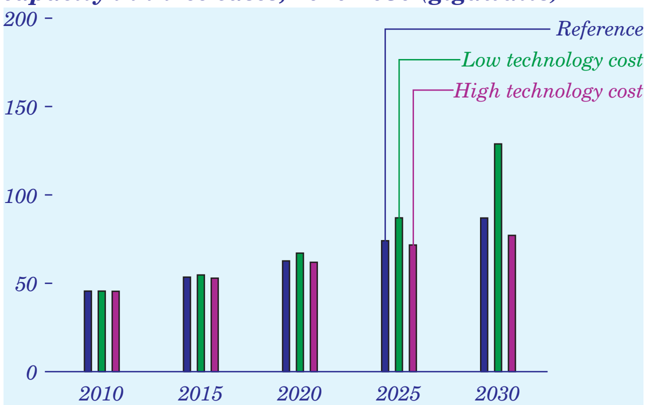


The *AEO2009* reference case includes both State RPS requirements and a risk premium on high-carbon generating technologies. As a result, total renewable electricity generation grows by nearly 380 billion kilowatthours, to 730 billion kilowatthours (14.2 percent of total domestic power production) in 2030. Environmental concerns and a scarcity of new large-scale sites limit the growth of conventional hydropower, and from 2007 to 2030 its share of total generation remains between 6 percent and 7 percent. Generation from nonhydroelectric alternatives increases, bolstered by legislatively mandated State RPS programs, technology advances, and State and Federal supports (Figure 61). Although the Federal PTC is assumed to expire after 2009 for wind and after 2010 for other renewables, nonhydropower renewable generation increases from 2.5 percent of total generation in 2007 to 8.3 percent in 2030.

Wind and biomass are the largest sources of electricity among the nonhydropower renewables. Initially helped by the Federal PTC, their growth continues as States meet their RPS requirements and more States enact RPS programs each year. Central-station solar is also growing rapidly in California. Although the technology remains costly, several credible project announcements have been made that would lead to capacity expansion in the hundreds of megawatts. Moreover, as States continue to organize regional climate pacts, renewable generation will become more prominent in carbon-constrained regions. The Northeast RGGI is the only such program included in the *AEO2009* reference case, but western States are moving forward quickly with their own programs.

Higher or Lower Costs Affect Trends in Renewable Generation Capacity

Figure 62. Nonhydropower renewable generation capacity in three cases, 2010-2030 (gigawatts)

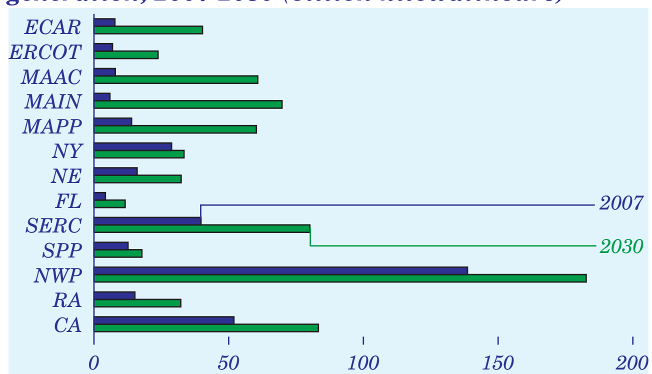


If the costs of renewable generation technologies decline significantly faster than projected in the *AEO-2009* reference case, there may be more new renewable capacity than is needed to meet State renewable generation mandates. The low renewable technology cost case assumes costs 25 percent lower than in the reference case in 2030, resulting in 38 percent more new wind capacity and 200 percent more new dedicated biomass capacity. New end-use solar capacity in 2030 is 49 percent above the reference case level, although the technology remains too expensive for widespread use in bulk power markets; geothermal, hydroelectric, and municipal solid waste capacity shows little change, because economical resources are limited. A significant increase in dedicated biomass capacity in the low cost case draws biomass away from less efficient co-firing operations and helps producers meet State RPS requirements.

In the *high renewable technology cost case*, the costs for renewable capacity remain at the reference case levels and "dedicated energy crops" are not developed, resulting in slightly less new renewable capacity in 2030 than in the reference case (Figure 62). State mandates still are expected to guarantee a significant amount of growth in renewable capacity, however, even with the higher costs. In the high cost case, biomass co-firing operations make a larger contribution to RPS compliance than in the reference case. Although many State RPS laws include cost containment measures that may limit overall compliance if renewable generation is more expensive than projected in the reference case, many of those provisions either are discretionary or cannot be analyzed fully in the high cost case.

State Portfolio Standards Increase Generation from Renewable Fuels

Figure 63. Regional growth in nonhydroelectric renewable electricity generation, including end-use generation, 2007-2030 (billion kilowatthours)



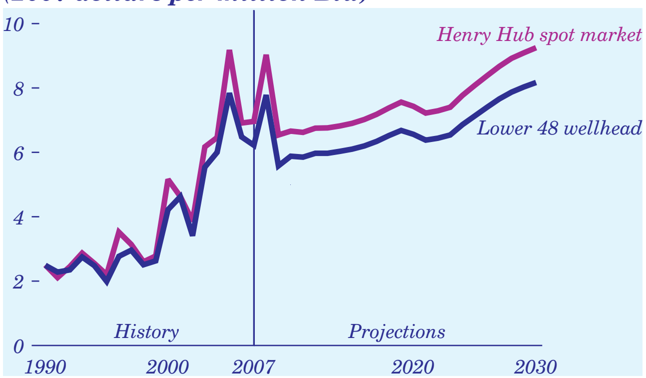
As of early November 2008, 28 States and the District of Columbia had legislatively mandated RPS programs. The mandatory programs are included in the reference case, but States' voluntary goals are not. Because NEMS does not provide projections at the State level, the reference case assumes that most States will reach their goals within each program's legislative framework, and the results are aggregated at the regional level. In some States, however, compliance could be limited by authorized funding levels for the programs. For example, California is not expected to meet its renewable energy targets because of limits on the authorized funding for its RPS program.

By region, the fastest growth in nonhydroelectric renewable generation is projected for MAIN (Figure 63). The largest share of wind power is in the MAIN region, which includes Illinois, Wisconsin, and parts of Michigan and Missouri. In Texas, generation from wind power grows until the Federal PTC expires on December 31, 2010, and resumes growth after 2020, when natural gas prices begin to rise more rapidly. Solar and geothermal energy are used in the Southwest. Biomass generates most of the required renewable energy in the Mid-Atlantic region, which in 2030 contains nearly 53 percent of the Nation's dedicated biomass capacity.

Most NEMS regions include at least one State with an RPS program (see Figure F2 in Appendix F for a map of the regions). The only area without widespread RPS programs is the Southeast, where North Carolina is the only State with an enforceable RPS.

Natural Gas Prices Rise As More Expensive Resources Are Produced

Figure 64. Lower 48 wellhead and Henry Hub spot market prices for natural gas, 1990-2030 (2007 dollars per million Btu)



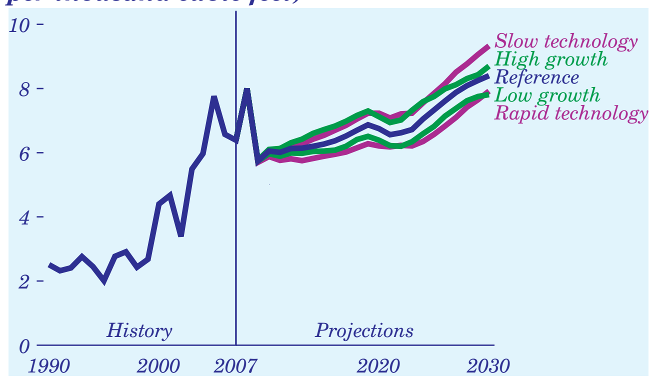
Average lower 48 wellhead prices for natural gas generally increase in the reference case, as more expensive domestic resources are used to meet demand. Prices decline for a brief period after the Alaska pipeline begins operation in 2020, but the market quickly absorbs the additional natural gas supplies from Alaska, and prices resume their rise (Figure 64).

Henry Hub spot market prices and delivered end-use natural gas prices generally follow the trend in lower 48 wellhead prices; however, delivered prices also are subject to variation in average transmission and distribution rates and resulting margins, as reflected in the difference between the average delivered price and the average supply price for natural gas. Some new pipelines are built to bring supplies to market and to reach new customers, but the bulk of the pipeline system is already in place, and revenue requirements for those segments decline as capital is depreciated. Consequently, transmission and distribution margins for natural gas delivered to the industrial and electric power sectors either remain flat or decline.

Natural gas distribution rates are determined in large part by consumption levels per customer, which decline in the residential and commercial sectors over the projection period. As a result, fixed costs are distributed over a smaller customer base, leading to slight increases in transmission and distribution margins in those sectors. In the transportation sector, transmission and distribution margins for natural gas used as fuel in CNG vehicles decline in real terms, as motor fuels taxes remain constant in nominal terms.

Prices Vary With Economic Growth and Technology Progress Assumptions

Figure 65. Lower 48 wellhead natural gas prices in five cases, 1990-2030 (2007 dollars per thousand cubic feet)



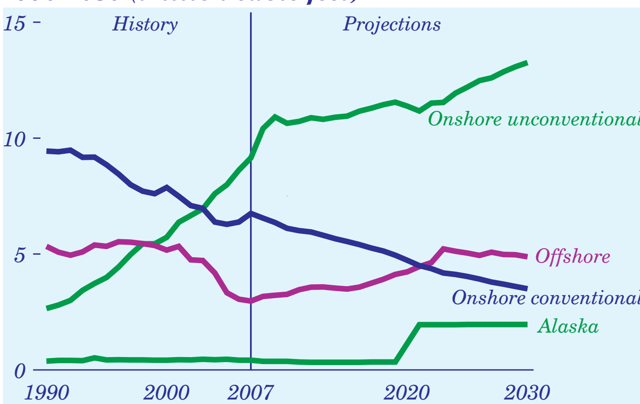
The extent to which natural gas prices increase in the *AEO2009* reference and alternative cases depends on assumptions about economic growth rates and the rate of improvement in natural gas exploration and production technologies. Technology improvements reduce drilling and operating costs and expand the economically recoverable resource base.

Technology improvement is particularly important in the context of growing investment in production of natural gas from shale formations, which generally can be produced more efficiently than the natural gas contained in conventional formations, but which require relatively high capital expenditures. The reference case assumes that annual technology improvements follow historical trends. In the rapid technology case, exploration and development costs per well decline at a faster rate, which allows for more growth in production. More rapid technology improvement puts downward pressure on natural gas prices, mitigated somewhat by higher levels of consumption than in the reference case. In the slow technology case, slower declines in exploration and development costs lead to higher natural gas prices than in the reference case.

In the *AEO2009* high economic growth case, natural gas consumption grows more rapidly, and natural gas prices rise more sharply, than in the reference case. In the low economic growth case, natural gas consumption grows more slowly, and natural gas prices are lower, than in the reference case (Figure 65).

Largest Source of U.S. Natural Gas Supply Is Unconventional Production

Figure 66. Natural gas production by source, 1990-2030 (trillion cubic feet)



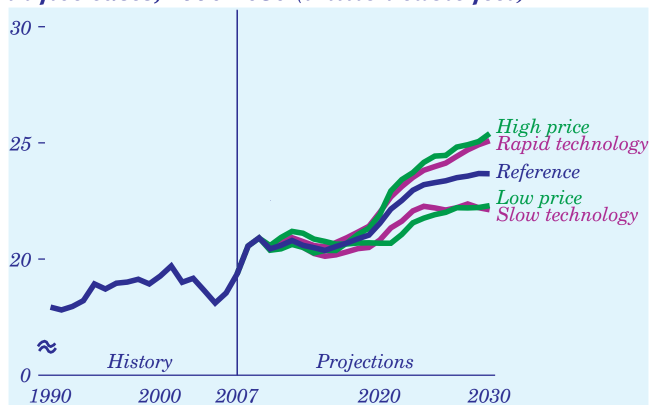
From 2007 to 2030, total natural gas production in the reference case increases by more than 4 trillion cubic feet, even as onshore lower 48 conventional production (from smaller and deeper deposits) continues to taper off. Unconventional natural gas is the largest contributor to the growth in U.S. natural gas production, as rising prices and improvements in drilling technology provide the economic incentives necessary for exploitation of more costly resources. Unconventional natural gas production increases from 47 percent of the U.S. total in 2007 to 56 percent in 2030 (Figure 66).

Natural gas in tight sand formations is the largest source of unconventional production, accounting for 30 percent of total U.S. production in 2030, but production from shale formations is the fastest growing source. With an assumed 267 trillion cubic feet of undiscovered technically recoverable resources, production of natural gas from shale formations increases from 1.2 trillion cubic feet in 2007 to 4.2 trillion cubic feet, or 18 percent of total U.S. production, in 2030. The expected growth in natural gas production from shale formations is far from certain, however, and continued exploration is needed to provide additional information on the resource potential.

Offshore production also makes up a significant portion of domestic natural gas supply, accounting for 15 percent of total domestic production in 2007 and 21 percent in 2030. The increase in offshore production is largely from deepwater formations and OCS areas recently released from Congressional moratoria.

World Oil Prices and Technology Progress Affect Natural Gas Supply

Figure 67. Total U.S. natural gas production in five cases, 1990-2030 (trillion cubic feet)



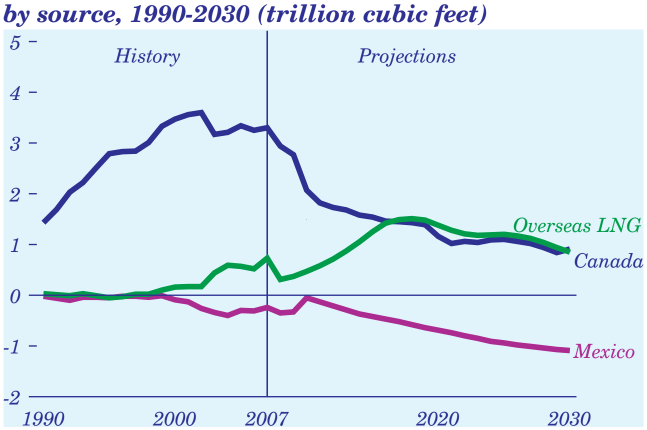
Improvements in natural gas exploration and development technologies reduce drilling costs, increase production capacity, and ultimately lower wellhead prices, increasing both production levels and end-use consumption. More rapid technology improvement raises the potential level of natural gas production and offsets the effects of depletion of the resource base, particularly for onshore conventional resources. In the rapid technology case, natural gas production in 2030 is 1.4 trillion cubic feet higher than in the reference case; in the slow technology case, it is 1.5 trillion cubic feet lower than in the reference case.

The impact of world oil prices on domestic natural gas production is indirect, affecting natural gas consumption and, to a lesser degree, LNG imports. In the high oil price case, natural gas production in 2030 is 1.7 trillion cubic feet higher than in the reference case (Figure 67), with most of the additional supply, 1.2 trillion cubic feet, being used for GTL production. In addition, higher oil prices reduce liquids consumption, leading to a decline in crude oil processing at refineries, so that more natural gas is consumed at refineries to replace still gas that otherwise would be available for refinery use. Higher levels of natural gas consumption for CTL production and refinery use in the high price case are offset to some extent by a decline in natural gas use for electricity generation.

In the low oil price case, refineries use less natural gas. Also, with less expensive crude oil taking a larger share in world energy markets, more natural gas is available for export to the United States as LNG. Domestic natural gas production is therefore lower, and LNG imports are higher, than in the reference case.

U.S. Net Imports of Natural Gas Decline in the Projection

Figure 68. Net U.S. imports of natural gas by source, 1990-2030 (trillion cubic feet)



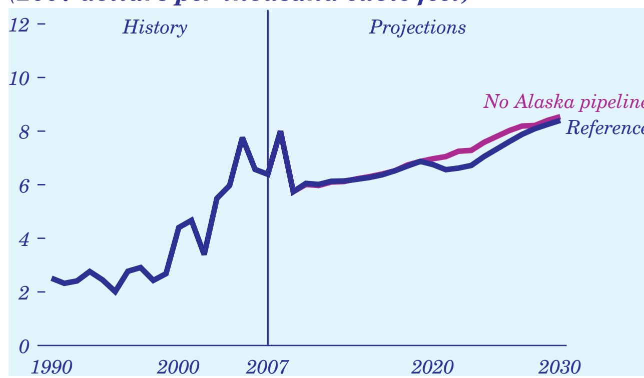
U.S. net imports of natural gas decline in the *AEO-2009* reference case from 16 percent of supply in 2007 to 3 percent in 2030. The reduction is a result primarily of lower imports from Canada and higher exports to Mexico because of growing demand for natural gas in each of those countries. In addition, with relatively high prices and advances in technology, the potential for U.S. domestic natural gas production (particularly from unconventional sources) increases, providing a competitive alternative to imports of LNG.

Conventional natural gas production from Canada's Western Sedimentary Basin has been declining in recent years. In the reference case, Canada's unconventional production does not increase rapidly enough to keep up with domestic demand growth while maintaining current export levels. For Mexico, U.S. pipeline exports are needed to meet the country's growth in demand for natural gas, which is not matched by increases in domestic production and LNG imports.

In the United States, LNG imports peak at 1.5 trillion cubic feet in 2018 before declining to 0.8 trillion cubic feet in 2030 (Figure 68), despite projected U.S. regasification capacity of 5.2 trillion cubic feet. The near-term increase is the result of growth in world liquefaction capacity, which temporarily exceeds world demand, making LNG available to the U.S. market—particularly in the summer to fill storage facilities. In the longer term, high LNG prices (which are tied to oil prices in many markets) and ample domestic natural gas supplies reduce U.S. demand for LNG imports; however, the amount of LNG available to U.S. markets could change if world natural gas consumption differs from the levels projected in the reference case.

With No Alaska Pipeline, Lower 48 Prices for Natural Gas Are Higher

Figure 69. Lower 48 wellhead prices for natural gas in two cases, 1990-2030 (2007 dollars per thousand cubic feet)



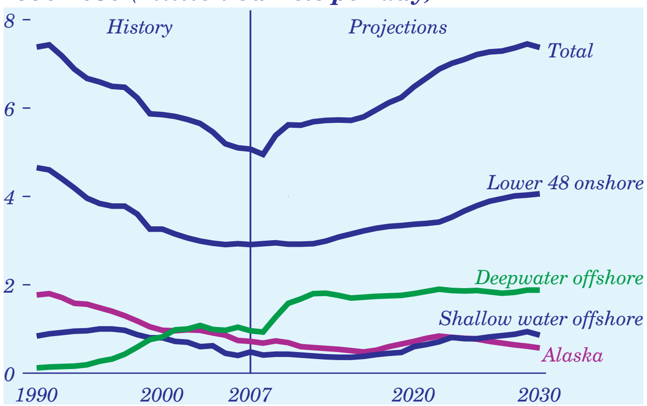
The *AEO2009* reference case assumes that a proposed pipeline to transport natural gas from Alaska's North Slope to Alberta, Canada, and ultimately to the lower 48 States will be built in 2020, and that Alaska's natural gas production will increase by 1.6 trillion cubic feet as a result. The no Alaska pipeline case assumes that the pipeline will not be built, leading to higher prices in lower 48 natural gas markets, more lower 48 production and imports of natural gas, and lower consumption.

The largest impact on natural gas prices in the no Alaska pipeline case occurs when the pipeline reaches full capacity in 2022, two years after the pipeline begins operating in the reference case. In 2022, Henry Hub spot market prices for natural gas (in 2007 dollars) are higher by $0.63 per thousand cubic feet in the no Alaska pipeline case than in the reference case. After 2022 the price impact lessens gradually, to $0.13 per thousand cubic feet in 2030 (Figure 69). In 2026, total natural gas consumption is 0.8 trillion cubic feet lower in the no pipeline case than in the reference case, and consumption for electricity generation is 0.3 trillion cubic feet lower.

Higher natural gas prices and reduced supply in the no pipeline case lead to more unconventional production and LNG imports in the lower 48 States. Pipeline imports from Canada, which in the no pipeline case do not compete with Alaska natural gas in lower 48 markets, are 0.5 trillion cubic feet above the reference case level in 2028. LNG imports are only slightly higher in the no pipeline case, as a result of increased competition in world markets and the availability of domestic natural supplies at competitive prices.

U.S. Crude Oil Production Increases With Rising Oil Prices

Figure 70. Domestic crude oil production by source, 1990-2030 (million barrels per day)



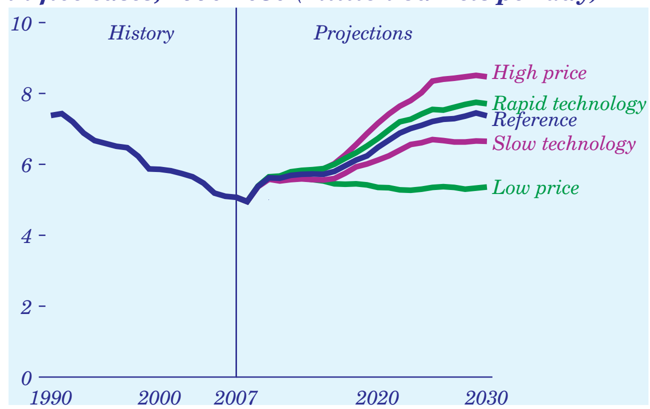
The long-term decline in total U.S. crude production has slowed over the past few years, as higher world oil prices have spurred drilling. In the projections, total U.S. domestic crude oil production, which has been falling for many years, begins to increase in 2009. Most of the near-term increase is from the deepwater offshore. Growth is limited after 2010, however, because newer discoveries are smaller, and capital expenditures rise as development moves into deeper waters.

A number of deepwater discoveries in the Gulf of Mexico have begun to ramp up production recently or are expected to begin production by the end of 2009. The largest include Shenzi, Atlantis, Blind Faith, and Thunder Horse. Expiration of the Congressional moratoria on the Eastern Gulf of Mexico, Atlantic, and Pacific regions of the OCS also allow crude oil production to increase in the Atlantic and Pacific OCS after 2014 and in the Eastern Gulf of Mexico OCS after 2025. Total offshore production increases at an average annual rate of 2.8 percent, from 1.4 million barrels per day in 2007 to 2.7 million barrels per day in 2030.

U.S. onshore crude oil production also increases throughout the projection, primarily as a result of increased application of CO_2-enhanced oil recovery techniques, exploitation of oil from the Bakken shale formation [*98*], and the startup of liquids production from oil shale, which is supported by favorable world oil prices and continued advances in oil shale extraction technology. Total onshore production of crude oil increases from 2.9 million barrels per day in 2007 to 4.1 million barrels per day in 2030 (Figure 70).

U.S. Oil Production Depends on Prices, Access, and Technology

Figure 71. Total U.S. crude oil production in five cases, 1990-2030 (million barrels per day)

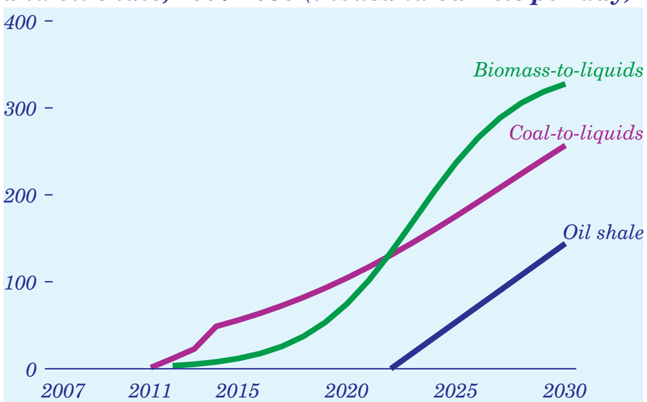


U.S. crude oil production is highly sensitive to world crude oil prices, because the remaining domestic resource base generally requires more costly secondary or tertiary recovery techniques, which are likely to be uneconomical when world oil prices are low. Even when prices are higher, however, high-cost projects typically involve long lead times from discovery to production, which limit their impact on total production levels. In the high oil price case, U.S. crude oil production in 2030 is 1.1 million barrels per day higher than in the reference case, mostly as a result of increased production from onshore CO_2-enhanced oil recovery projects and offshore deepwater projects. In the low oil price case, crude oil production in 2030 is 2.0 million barrels per day lower than in the reference case, primarily because of lower production from CO_2-enhanced recovery projects, and because fewer projects in the lower 48 offshore and Alaska's North Slope are economical when world oil prices are relatively low.

Both onshore and offshore production generally increase as technology advances reduce the costs of exploration and development. In the rapid technology case, U.S. crude oil production in 2030 is 0.3 million barrels per day higher than in the reference case, with most of the increase coming from resources in the lower 48 offshore. In the slow technology case, crude oil production in 2030 is 0.7 million barrels per day lower than in the reference case (Figure 71). Most of the difference between the 2030 production levels in the reference and slow technology cases results from lower levels of production from CO_2-enhanced oil recovery in the slow technology case.

BTL, CTL, and Oil Shale Production Grows With Technology Improvement

Figure 72. Liquids production from gasification and oil shale, 2007-2030 (thousand barrels per day)



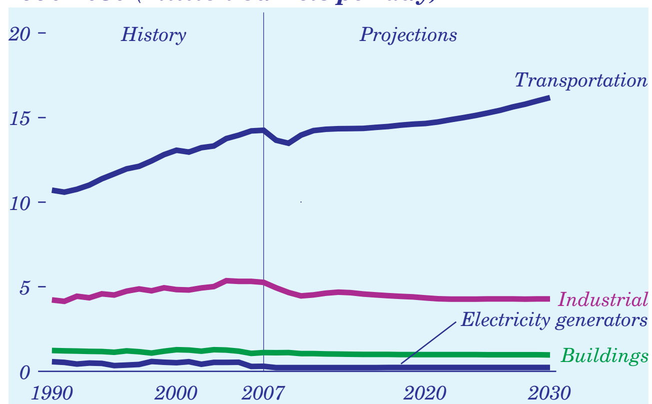
Production of liquid fuels from oil shale, coal, natural gas, and biomass becomes viable over time in the reference case as a result of continued technology improvements and rising oil prices. Growth in their production can be moderated, however, by rising capital costs and by the enactment of more stringent environmental regulations affecting water and land use—which increase production costs—and GHG emissions. Consequently, penetration rates vary for the different production processes.

BTL production begins in 2012 in the reference case and grows by an average of 29 percent per year through 2030 (Figure 72). CTL production begins in 2011 and grows by an average of 19 percent per year. The increase in CTL production would be larger if it were not constrained by the reference case assumption that growing concern about GHG emissions will limit investment in the carbon-intensive CTL technology.

Oil shale production begins later, in 2023, but increases rapidly, averaging 35 percent per year from 2023 to 2030. Research and development efforts are expected to provide the necessary technology improvements to yield commercial quantities of liquids from oil shale production that, over time, can be further increased in scale. Although no GTL production is expected before 2030 in the reference case, GTL production in Alaska begins in 2017 in the high oil price case and then grows by an average of 21 percent per year from 2017 to 2030.

Transportation Sector Dominates Liquid Fuels Consumption

Figure 73. Liquid fuels consumption by sector, 1990-2030 (million barrels per day)



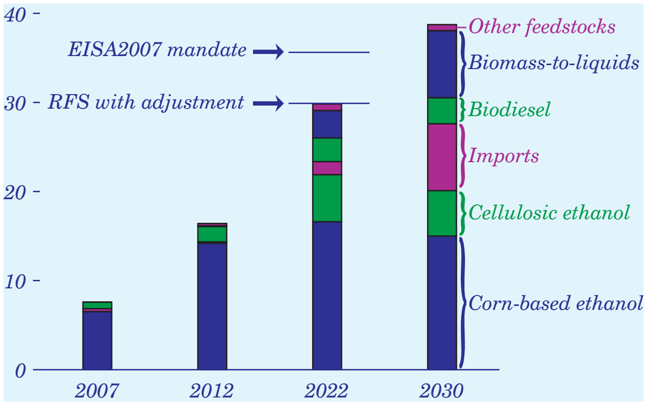
The transportation sector continues to dominate liquid fuels consumption in the projections (Figure 73), with large increases in the use of diesel fuel and biofuels. In the reference case, total consumption of petroleum-based motor gasoline in 2030, including E10 but excluding E85, is 1.3 million barrels per day below the 2007 total, whereas both consumption of diesel fuel and consumption of E85 increase, by about 1.5 million barrels per day each. Biofuel consumption grows with the EISA2007 mandates, and diesel fuel consumption expands as more light-duty diesel vehicles are produced by automotive manufacturers seeking to comply with new CAFE standards. Diesel fuel use for freight trucks also increases as industrial output expands.

In the other sectors, liquid fuels consumption declines through 2030. Industrial use of liquids drops by 19 percent, despite a 47-percent increase in industrial shipments. Much of the decline from 2007 to 2030 results from changes in the chemical industry, where there is a shift in the production mix, and energy efficiency improves. Liquid fuels consumption in the buildings sector continues to fall, as fewer buildings use oil for heating, and efficiency improves as older systems are replaced with more efficient equipment.

Liquid fuels consumption in the electric power sector declines as a result of slowing growth in demand for electricity from 2007 to 2030. With Federal and State efficiency standards minimizing the need for new generating capacity, little new oil-fired capacity is installed, and generation from older oil-fired capacity is offset by production from new capacity using coal, natural gas, nuclear, and renewable fuels.

EISA2007 RFS Mandate for 2022 Is Met in 2027

Figure 74. RFS credits earned in selected years, 2007-2030 (billion credits)



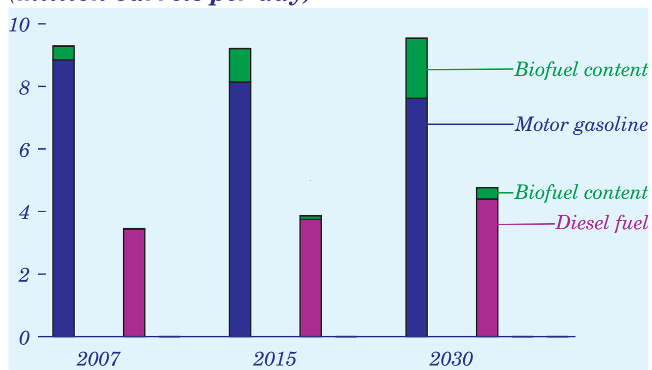
EISA2007 mandates a total RFS credit requirement of 36 billion gallons in 2022. Credits are equal to gallons produced, except for fatty acid methyl ester biodiesel and BTL diesel, which receive a 1.5-gallon credit for each gallon produced. The renewable fuels can be grouped into two categories: conventional biofuels (ethanol produced from corn starch) and advanced biofuels (including cellulosic ethanol, biodiesel, and BTL diesel). In total, 15 billion gallons of credits from conventional biofuels and 21 billion gallons from advanced biofuels are required in 2022.

In the *AEO2009* reference case, the credit requirement for conventional biofuels is met in 2022, but the requirement for advanced fuels is not. In that event, EISA2007 provides for both the application of waivers and modification of applicable credit volumes. The RFS mandates are achieved in 2027 in the reference case, and as BTL production grows, the overall target of 36 billion gallons is exceeded in 2030 (Figure 74).

Progress toward meeting the RFS is complicated by slowing growth in U.S. petroleum use through 2030. The push for more fuel-efficient automobiles, which slows the increase in motor gasoline consumption in the reference case, also slows progress toward meeting the RFS, because more efficient gasoline engines and growing penetration of hybrids reduce the demand for ethanol in gasoline fuel blends. A 10-percent limit on ethanol in gasoline for most of the current fleet of passenger vehicles delays further market penetration until more E85-compatible vehicles are in use and the market infrastructure for E85 and other biofuels is expanded to accommodate the distribution and sale of growing volumes.

Biofuels Displace Conventional Fuels in the Transportation Mix

Figure 75. Biofuel content of U.S. motor gasoline and diesel consumption, 2007, 2015, and 2030 (million barrels per day)



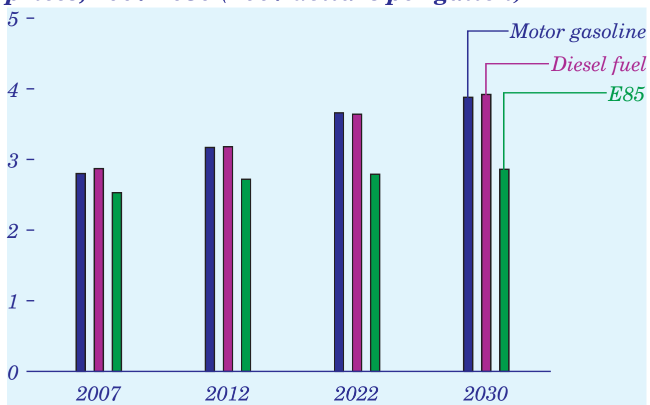
As a result of the RFS in EISA2007, CAFE standards, and higher liquid prices, biofuels in the form of ethanol and biodiesel displace a growing portion of the fossil fuel component of transportation fuel use in the reference case (Figure 75). With biofuels representing all the growth in motor fuel supply, there is virtually no growth in petroleum consumption through 2030, as demand for petroleum-based gasoline declines and demand for petroleum-based diesel grows modestly. The growing share for diesel fuel is similar to recent trends in Europe, where increases in diesel use have outpaced the growth in gasoline use for some time, causing European refineries to be reconfigured for more diesel production.

U.S. production of biofuels grows from less than 0.5 million barrels per day in 2007 to 2.3 million barrels per day in 2030. Ethanol production provides the largest share of that growth, as ethanol use for gasoline blending grows to more than 0.8 million barrels per day and ethanol consumption in E85 increases to 1.1 million barrels per day in 2030. Much of the growth in demand for E85 occurs after 2015, when the market for E10 blending is saturated. Although most of the ethanol consumed is produced domestically, net imports of ethanol also increase, to 0.5 million barrels per day in 2030.

To meet RFS and CAFE standards, the vehicle fleet changes dramatically in the reference case. In 2030, 60 percent of the new LDVs sold are E85, flex-fuel, conventional hybrid, or PHEVs.

Ethanol Prices Compete on a Btu Basis To Meet the EISA2007 RFS

Figure 76. Motor gasoline, diesel fuel, and E85 prices, 2007-2030 (2007 dollars per gallon)



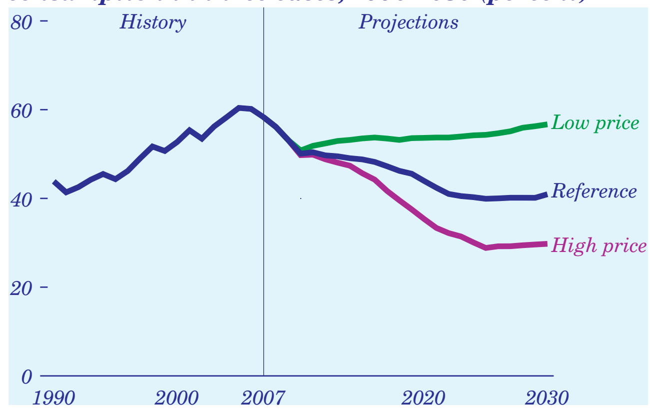
With crude oil prices rising in the reference case, prices for both gasoline and diesel fuel increase by an average of 1.4 percent per year, to about $4 per gallon (2007 dollars) in 2030 (Figure 76). The average increase in E85 prices is 0.5 percent per year over the same period, and the E85 price in 2030 is less than $3 per gallon. As a result, the difference between gasoline and E85 prices increases from roughly 30 cents per gallon in 2007 to more than a dollar per gallon in 2030.

In the reference case, ethanol is used initially as a blending component with gasoline, but the U.S. market for ethanol blending with gasoline to make E10 is near saturation by 2012. Meeting the EISA2007 RFS after 2012 therefore requires increased consumption of E85. To encourage the use of E85, its price (in terms of energy content) must be equivalent to or below the price of motor gasoline. E85 prices increase only moderately in the reference case, to $2.72 per gallon in 2012 and $2.79 in 2022, on the path to achieving the sales volume needed to meet the RFS mandate.

The increase in ethanol sales requires construction of a sufficient base of E85 fueling stations and distribution infrastructure to ensure the commercial viability of a growing fleet of E85 vehicles. *AEO2009* assumes that the average cost to modify an existing service station for E85 sales will be about $46,000. Assuming no intermediate ethanol blends, E85 prices must be subsidized by refiners and marketers through high prices for gasoline and diesel fuel in order to meet the mandated ethanol level in the RFS once the E10 market is saturated and E85 is the primary contributor.

Imports of Liquid Fuels Vary With World Oil Price Assumptions

Figure 77. Net import share of U.S. liquid fuels consumption in three cases, 1990-2030 (percent)

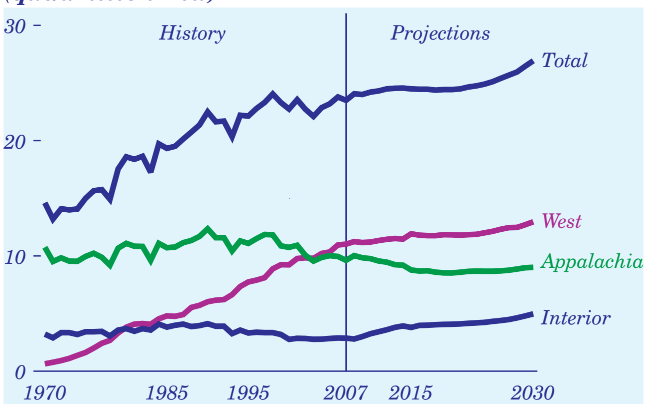


U.S. imports of liquid fuels, which grew steadily from the mid-1980s to 2005, decline sharply from 2007 to 2030 in the reference and low oil price cases, even as they continue to provide a major part of total U.S. liquids supply. Increasing use of biofuels, much of which are domestically produced, tighter CAFE standards, and higher energy prices moderate the growth in demand for liquids. A combination of higher prices and mandates leads to increased domestic production of oil and biofuels. In the reference case, there is essentially no growth in the use of liquid fuels from 2007 to 2030.

The net import share of U.S. liquid fuels consumption fell from 60 percent in 2005 to 58 percent in 2007. That trend continues in the reference case, with a net import share of 41 percent in 2030, and in the high oil price case, with a 30-percent share in 2030. In the low price case, the net import share falls in the near term before rising to 57 percent in 2030. With lower prices for liquid fuels, demand increases while domestic production decreases, and more imports are needed to meet demand. With higher prices, the need for imports is smaller but still substantial (Figure 77). Increased penetration of biofuels in the liquids market reduces the need for imports of crude oil and petroleum products in the high price case.

Total Coal Production Increases at a Slower Rate Than in the Past

Figure 78. Coal production by region, 1970-2030 (quadrillion Btu)



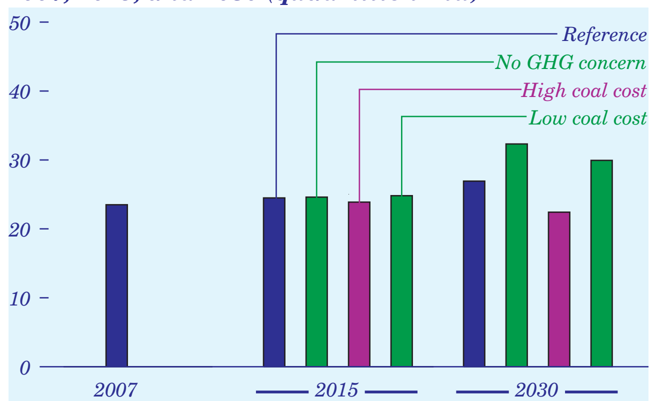
In the *AEO2009* reference case, increasing coal use for electricity generation at both new and existing plants and the startup of several CTL plants lead to modest growth in coal production, averaging 0.6 percent per year from 2007 to 2030—slightly less than the 0.9-percent average growth rate for U.S. coal production from 1980 to 2007.

Western coal production, which has grown steadily since 1970, continues to increase through 2030 (Figure 78), but at a much slower rate than in the past. Most of the additional output originates from mines located in Wyoming, Montana, and North Dakota. Roughly one-half of the West's additional coal production is used for fuel and feedstock at new CTL plants, and the remainder is used for electricity generation at existing and new coal-fired power plants.

Production of higher sulfur coal in the Interior region, which has trended downward since the early 1990s, rebounds as existing coal-fired power plants are retrofitted with flue gas desulfurization (FGD) equipment and new coal-fired capacity is added in the Southeast. Much of the additional output from the Interior region originates from mines tapping into the extensive reserves of mid- and high-sulfur bituminous coal in Illinois, Indiana, and western Kentucky. In Appalachia, total production declines slightly from current levels as output shifts from the extensively mined, higher cost reserves of Central Appalachia to lower cost supplies from the Interior region, South America, and the northern part of the Appalachian basin.

Long-Term Production Outlook Varies Considerably Across Cases

Figure 79. U.S. coal production in four cases, 2007, 2015, and 2030 (quadrillion Btu)



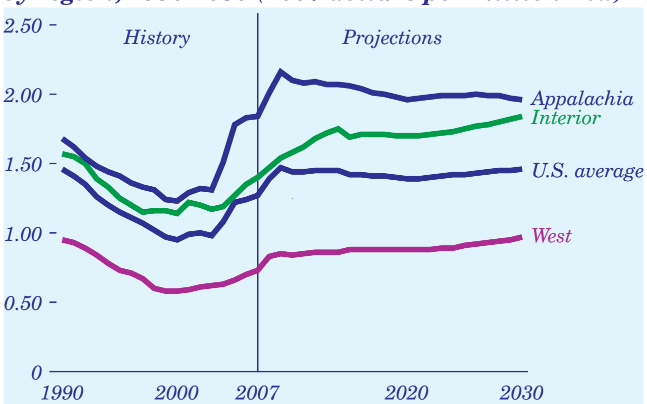
U.S. coal production varies across the *AEO2009* cases, in particular when different policies are assumed with regard to GHG emissions. Different assumptions about the costs of producing and transporting coal also lead to substantial variations in the outlook for coal production.

The no GHG concern case illustrates the potential for a sizable increase in coal production. In the absence of a risk premium for carbon-intensive technologies, more new coal-fired power plants and CTL plants are built than in the reference case. In 2030, coal production in the no GHG concern case is 20 percent above the reference case projection (Figure 79). In contrast, if policies to reduce or limit GHG emissions were enacted in the future, they could result in significant reductions in coal use at existing power plants and limit the amount of new coal-fired capacity built in the future. The impact on coal use would depend on details of the policies, such as the allocation of emissions allowances, the inclusion of a "safety valve" or other mechanism to limit the price of allowances (and its level), and the inclusion of provisions to encourage the use of particular fuels or technologies.

In the high coal cost case, higher costs for coal mining and transportation lead to some switching from coal to natural gas and nuclear in the electric power sector, along with slightly slower growth in electricity demand. In the low coal cost case, the trends are in the opposite direction. As a result, coal production in 2030 is 17 percent lower in the high coal cost case, and 11 percent higher in the low coal cost case, than in the reference case.

Minemouth Coal Prices in the Western and Interior Regions Continue Rising

Figure 80. Average minemouth coal prices by region, 1990-2030 (2007 dollars per million Btu)



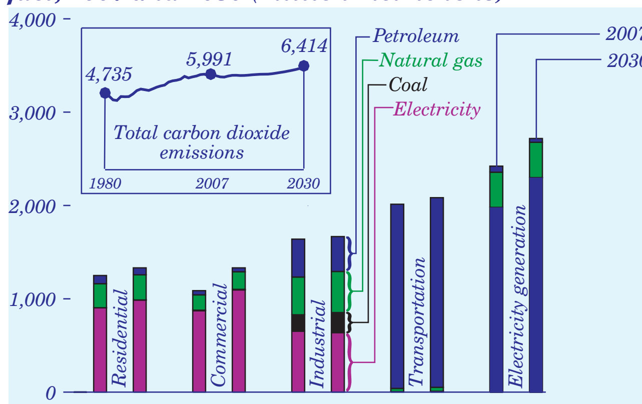
In the near term, rising prices for the mining equipment, parts and supplies, and fuel used at coal mines lead to higher minemouth prices for coal in all regions (Figure 80). In the Appalachian region, a resurgence in production of high-value coal for export adds to the early price surge. In the longer term, limited improvement in coal mining productivity and increased production from the Interior and Western supply regions result in higher minemouth prices in both regions, increasing on average by 1.2 percent per year from 2007 to 2030. After peaking in 2009, the average minemouth price for Appalachian coal declines by 0.5 percent per year through 2030, as a result of falling demand and a shift to lower cost production in the northern part of the basin.

Reflecting regional trends, the U.S. average minemouth price of coal rises significantly between 2007 and 2009, from $1.27 to $1.47 per million Btu. After the initial run-up, however, prices level off and then fall slightly through 2020, as mine capacity utilization declines and production shifts away from the higher cost mines of Central Appalachia.

In the reference case, the assumed risk premium for carbon-intensive technologies dampens investment in new coal-fired power plants; however, a growing need for additional generating capacity of all types results in the construction of 28 gigawatts of new coal-fired capacity after 2020. The combination of new investment in mining capacity to meet demand growth and a continued low rate of productivity improvement leads to an increase in the average minemouth price of coal, from $1.39 per million Btu in 2020 to $1.46 in 2030.

Rate of Increase in Carbon Dioxide Emissions Slows in the Projections

Figure 81. Carbon dioxide emissions by sector and fuel, 2007 and 2030 (million metric tons)



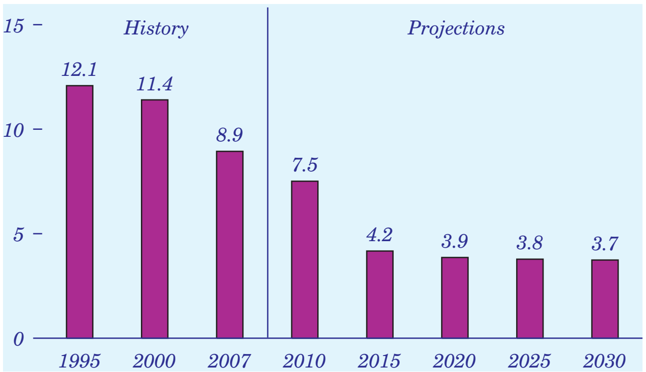
Even with rising energy prices, growth in energy use leads to increasing U.S. CO_2 emissions in the absence of explicit policies to reduce GHG emissions; however, the appliance efficiency, CAFE, and tax policies enacted in 2007 and 2008, slow the growth of U.S. energy demand, and as a result, energy-related CO_2 emissions in the *AEO2009* reference case grow by 0.3 percent per year from 2007 to 2030, as compared with 0.8 percent per year from 1980 to 2007. In 2030, energy-related CO_2 emissions total 6,414 million metric tons, about 7 percent higher than in 2007.

Slower emissions growth is also, in part, a result of the declining share of electricity generation that comes from fossil fuels—primarily, coal and natural gas—and the growing renewable share, which increases from 8 percent in 2007 to 14 percent in 2030. As a result, while electricity generation increases by 0.9 percent per year, CO_2 emissions from electricity generation increase by only 0.5 percent per year. The largest share of U.S. CO_2 emissions comes from electricity generation (Figure 81).

The U.S. economy becomes less carbon intensive as CO_2 emissions per dollar of GDP decline by 39 percent and emissions per capita decline by 14 percent over the projection. Increased demand for energy services is offset in part by shifts toward less energy-intensive industries, efficiency improvements, and increased use of renewables and other less carbon-intensive energy fuels. More rapid improvements in technologies that emit less CO_2, new CO_2 mitigation requirements, or more rapid adoption of voluntary CO_2 emissions reduction programs could result in lower CO_2 emissions levels than are projected here.

Without Clean Air Interstate Rule, Sulfur Dioxide Emissions Still Decline

Figure 82. Sulfur dioxide emissions from electricity generation, 1995-2030 (million short tons)



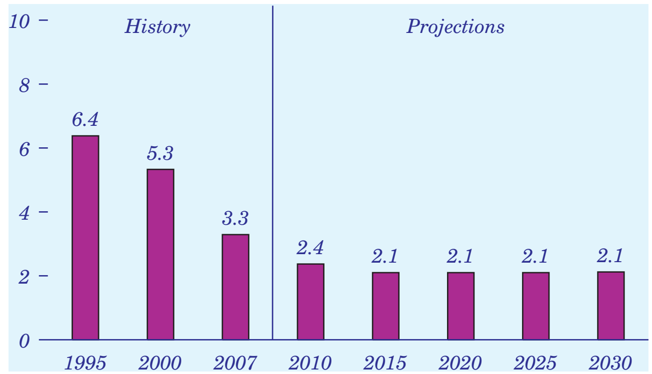
CAIR is not included in the *AEO2009* reference case, because in July 2008 the U.S. Court of Appeals vacated and remanded the rule, which included a cap-and-trade system to reduce SO_2 emissions. The same court has since temporarily reinstated CAIR, but that ruling was not issued until December 2008, and the *AEO2009* projections are based on laws and regulations in effect as of November 2008.

The reference case assumes that the States will mandate SO_2 emissions controls, such as FGD or the use of low-sulfur coal, to meet emissions goals even without CAIR. As a result, SO_2 emissions from electric power plants in 2030 in the reference case are more than 50 percent below their 2007 level (Figure 82), similar to projections in previous *AEO*s that assumed CAIR would be in effect. SO_2 emissions fall even though coal-fired generating capacity expands, as more than 114 gigawatts of existing coal-fired capacity is retrofitted with FGD equipment in the reference case through 2030. Because SO_2 allowance trading under CAIR is not included in *AEO2009*, there is no SO_2 allowance trading. With the reinstatement of CAIR, allowance trading and allowance prices will be included in future analyses.

The amount of new coal-fired capacity added in the reference case has little impact on SO_2 emissions, because it is assumed that all new capacity will include extensive emissions control systems. In contrast, implementation of a GHG emissions control policy could lower SO_2 and other emissions significantly by reducing generation from older, less efficient coal-fired power plants without FGD equipment.

Nitrogen Oxide Emissions Also Decline in the Reference Case

Figure 83. Nitrogen oxide emissions from electricity generation, 1995-2030 (million short tons)



Even without the CAIR mandates, States will need to reduce NO_x emission in order to meet the CAA standards for ground-level ozone. The *AEO2009* reference case assumes that individual States will enact their own mandates for NO_x emissions controls, which will meet the targets originally outlined in CAIR. Because it is assumed that the States will not use a cap-and-trade program, there is no allowance price for NO_x.

In the reference case, NO_x emissions in 2030 are about 35 percent below the 2007 level (Figure 83). Just as in the case of SO_2 emissions, the reduction occurs even as more electricity is generated at coal-fired power plants. The reference case assumes that the States will require older coal-fired plants to be retrofitted with selective catalytic control (SCR) equipment, and that new plants will be required to have pollution control equipment that meets the CAA New Source Performance Standards. Through 2030, an estimated 95 gigawatts of existing coal-fired capacity is retrofitted with SCR equipment in the reference case.

In the future, enactment of policies to limit or reduce GHG emissions could affect NO_x emissions from electricity generation. Controlling GHG emissions would require changes in the utilization of existing coal-fired capacity that would also reduce emissions of NO_x.

Endnotes for Market Trends

94. The energy-intensive manufacturing sectors include food, paper, bulk chemicals, petroleum refining, glass, cement, steel, and aluminum.
95. S.C. Davis and S.W. Diegel, *Transportation Energy Data Book: Edition 25*, ORNL-6974 (Oak Ridge, TN, May 2006), Chapter 4, "Light Vehicles and Characteristics," web site http://cta.ornl.gov/data/chapter4.shtml.
96. Unless otherwise noted, the term "capacity" in the discussion of electricity generation indicates utility, nonutility, and CHP capacity. Costs reflect the average of regional costs, except that a representative region is used to estimate costs for wind plants.
97. Customer-sited PV does not include off-grid PV. Based on 1989-2006 annual PV shipments, EIA estimates that as much as 210 megawatts of remote PV applications for electricity generation (off-grid power systems) were in service in 2006, plus an additional 526 megawatts in communications, transportation, and assorted other non-grid-connected, specialized applications. See Energy Information Administration, *Annual Energy Review 2007*, DOE/EIA-0384 (2007) (Washington, DC, June 2008), Table 10.8, "Photovoltaic Cell and Module Shipments by End Use and Market Sector, 1989-2006," web site www.eia.doe.gov/emeu/aer/renew.html. The approach used to develop the table, based on shipment data, provides an upper estimate of the size of the PV stock, including both grid-based and off-grid PV. It overestimates the size of the stock, because shipments include a substantial number of units that are exported, and each year some of the PV units installed in earlier years are retired from service or abandoned.
98. Energy Information Administration, "The Bakken Formation Helps Increase U.S. Proved Reserves of Oil," *This Week in Petroleum* (March 4, 2009), web site http://tonto.eia.doe.gov/oog/info/twip/twiparch/090304/twipprint.html.

Comparison With Other Projections

Comparison with Other Projections

Only IHS Global Insight (IHSGI) produces a comprehensive energy projection with a time horizon similar to that of *AEO2009*. Other organizations, however, address one or more aspects of the U.S. energy market. The most recent projection from IHSGI, as well as others that concentrate on economic growth, international oil prices, energy consumption, electricity, natural gas, petroleum, and coal, are compared here with the *AEO2009* projections.

Economic Growth

Projections of the average annual real GDP growth rate for the United States from 2007 through 2010 range from 0.2 percent to 3.1 percent (Table 15). Real GDP grows at an annual rate of 0.6 percent in the *AEO2009* reference case over the period, significantly lower than the projections made by the Office of Management and Budget (OMB), the Bureau of Labor Statistics (BLS), and the Social Security Administration (SSA)—although not all of those projections have been updated to take account of the current economic downturn. The *AEO2009* projection is slightly lower than the projection by IHSGI and slightly higher than the projection by the Interindustry Forecasting Project at the University of Maryland (INFORUM). In March 2009, the consensus Blue Chip projection was for 2.2-percent average annual growth from 2007 to 2010.

The range of GDP growth rates is narrower for the period from 2010 to 2015, with projections ranging from 2.1 to 3.8 percent per year. The average annual GDP growth of 3.2 percent in the *AEO2009* reference case from 2010 to 2015 is mid-range, with the Congressional Budget Office (CBO) projecting a stronger recovery from the recession. CBO projects average annual GDP growth of 3.8 percent, IHSGI projects growth of 3.1 percent, and the INFORUM, SSA, and International Energy Agency (IEA) projections all project growth that is below the *AEO2009* reference case projection.

There are few public or private projections of GDP growth for the United States that extend to 2030. The *AEO2009* reference case projects 2.5-percent average annual GDP growth from 2007 to 2030, consistent with the trend in expected labor force and productivity growth. IHSGI projects GDP growth from 2007 to 2030 at 2.4 percent, and INFORUM expects lower GDP growth at 2.2 percent over the same period. INFORUM also projects lower growth in productivity and the labor force.

Table 15. Projections of annual average economic growth rates, 2007-2030

Projection	Average annual percentage growth rates			
	2007-2010	2010-2015	2015-2020	2020-2030
AEO2008 (reference case)	2.5	2.7	2.4	2.4
AEO2009 (reference case)	0.6	3.2	2.6	2.6
IHSGI (November 2008)	0.7	3.1	2.8	2.5
OMB (June 2008)	2.9	2.9	NA	NA
CBO (January 2009)	0.2	3.8	2.3	NA
INFORUM (December 2008)	0.4	2.8	2.3	2.3
SSA (May 2008)	2.6	2.4	2.3	2.1
BLS (November 2007)	3.1	2.4	NA	NA
IEA (November 2008)	NA	2.1	NA	2.1
Blue Chip Consensus (March 2009)	2.2	2.8	2.7	NA

NA = not available.

World Oil Prices

Comparisons of the *AEO2009* cases with other oil price projections are shown in Table 16. In the *AEO2009* reference case, world oil prices rise from current levels to approximately $80 per barrel in 2010 and $110 per barrel in 2015. After 2015, prices increase to $130 per barrel in 2030. This price trend is higher than shown in the *AEO2008* reference case and, generally, more consistent with the *AEO2008* high oil price case.

Market volatility and different assumptions about the future of the world economy are reflected in the range of price projections for both the short term and the long term. The projections trend in different directions, with one group, the Institute of Energy Economics and the Rational Use of Energy at the University of Stuttgart (IER), showing prices stabilizing at around $70 per barrel by 2020 and remaining relatively constant through 2030 and another group, Energy Ventures Analysis, Inc. (EVA), showing prices rising steadily over the entire course of the projection period. Excluding the *AEO2009* reference case, the other projections range from $47 per barrel

Table 16. Projections of world oil prices, 2010-2030 (2007 dollars per barrel)

Projection	2010	2015	2020	2025	2030
AEO2008 (reference case)	75.97	61.41	61.26	66.17	72.29
AEO2008 (high price case)	81.08	92.77	104.74	112.10	121.75
AEO2009 (reference case)	80.16	110.49	115.45	121.94	130.43
DB	47.43	72.20	66.09	68.27	70.31
IHSGI	101.99	97.60	75.18	71.33	68.14
IEA (reference)	100.00	100.00	110.00	116.00	122.00
IER	65.24	67.03	70.21	72.37	74.61
EVA	57.09	74.61	95.33	105.25	116.21
SEER	54.82	98.40	89.88	82.10	75.00

to $102 per barrel in 2010, a span of $55 per barrel, and from $68 per barrel to $122 per barrel in 2030, a span of $54 per barrel. The wide range of the projections reflects the recent volatility of crude oil prices and the uncertainty inherent in the projections. The range of the other projections is encompassed in the range of the *AEO2009* low and high oil price cases, from $50 per barrel to $200 per barrel in 2030.

The world oil price measures are, by and large, comparable across projections. EIA reports the price of imported low-sulfur, light crude oil, approximately the same as the WTI prices that are widely cited as a proxy for world oil prices in the trade press. The only series that does not report projections in WTI terms is IEA's *World Energy Outlook 2008*, where prices are expressed as the IEA crude oil import price.

Total Energy Consumption

Both the *AEO2009* reference case and IHSGI projections show total energy consumption growing by 0.5 percent per year from 2007 to 2030. Given different totals for 2007, total energy consumption in 2030 in the IHSGI projection is about 1 quadrillion Btu lower than in the reference case. Growth rates by sector, however, differ between the two sets of projections (Table 17).

As shown in Table 16, energy prices in 2030 are higher in *AEO2009* than in the IHSGI projection. IHSGI's world oil price track is closer to the *AEO2009* low oil price case than the reference case. IHSGI's natural gas, coal, and electricity prices all are lower than those in the *AEO2009* reference case, but by a smaller percentage than the difference between the world oil price projections. As a result, IHSGI projects stronger growth in petroleum consumption, a key factor in its higher projections for energy consumption in the residential and industrial sectors. The *AEO2009* reference case includes stronger growth in the commercial and transportation sectors than the IHSGI projection.

In the residential sector, natural gas and electricity use in the IHSGI projection both grow significantly faster than in the *AEO2009* reference case. Factors slowing growth in the *AEO2009* reference case include increased lighting efficiency, a switch to a 10-year average from a 30-year average for heating and cooling degree-days, and a more detailed breakout for televisions, personal computers, and related equipment that better accounts for efficiency changes. In both projections, total housing stock grows by about 1.0 percent per year from 2007 to 2030.

The commercial sector is the least reliant on liquid fuels among the end-use sectors, and the difference in world oil prices between IHSGI and the *AEO2009* has the least impact on projections for commercial energy use. In the *AEO2009* reference case, commercial energy demand is driven by growth in commercial floorspace (divided into 11 building types), as well as by weather, population, and disposable income. Total commercial floorspace grows by 1.3 percent per year in the reference case. IHSGI cites commercial energy use per employee, which grows by 1.0 percent per year, about the same as in *AEO2009*. Consumption growth for both natural gas and electricity is higher in *AEO2009*, despite slightly higher prices. One aspect that could account for this difference is that IHSGI projects a population growth rate slightly below 0.8 percent per year from 2007 to 2030, as compared with 0.9 percent per year in the *AEO2009* reference case. For the industrial sector, IHSGI expects lower energy prices and more rapid growth in output, leading to more rapid increases in consumption of petroleum, natural gas, and electricity, than are projected in *AEO2009*.

Table 17. Projections of energy consumption by sector, 2007 and 2030 (quadrillion Btu)

	2007		2030		Average annual percentage growth, 2007-2030	
Sector	**AEO2009**	**IHSGI**	**AEO2009**	**IHSGI**	**AEO2009**	**IHSGI**
Residential	11.4	10.9	12.4	13.0	0.4	0.8
Commercial	8.5	8.4	10.6	9.9	1.0	0.7
Industrial	25.3	23.0	26.3	25.6	0.2	0.5
Transportation	28.8	28.5	31.9	30.0	0.4	0.2
Electric power	40.7	42.1	48.0	49.9	0.7	0.7
Less: electricity losses	-12.8	-12.8	-15.7	-16.1	—	—
Total primary energy	**101.9**	**100.1**	**113.6**	**112.3**	**0.5**	**0.5**

More than 97 percent of the energy consumed in the transportation sector in 2007 came from liquid fuels. Despite lower world oil prices in the IHSGI projection, the *AEO2009* reference case projects more rapid growth in transportation energy consumption. In both the *AEO2009* and IHSGI projections, an increase in diesel fuel use is offset by a decrease in motor gasoline use; however, the offset is more than 1 quadrillion Btu larger in the IHSGI projection. A more rapid increase in jet fuel consumption is projected by IHSGI, in line with its lower fuel prices.

Electricity

Table 18 provides a summary of the results from the *AEO2009* cases and compares them with other projections. For 2015, electricity sales range from a low of 3,960 billion kilowatthours in the *AEO2009* reference case to a high of 4,475 billion kilowatthours in the projection from IER, which also shows higher sales in the commercial and residential sectors and much higher growth in industrial sales than the *AEO2009* reference case. For 2030, both IHSGI and IER have higher projections for total electricity sales in 2030 than the 4,609 billion kilowatthours in the *AEO2009* reference case. IHSGI and IER also project higher residential and industrial sales in 2030 than the *AEO2009* reference case. IER projects commercial sales that are higher than both IHSGI and the *AEO-2009* reference case.

The *AEO2009* reference case shows declining real electricity prices after 2009 and then rising prices at the end of the period because of increases in the cost of fuels used for generation and increases in capital expenditures for construction of new capacity. The higher fossil fuel prices and capital expenditures in the *AEO2009* reference case result in an increase in the average electricity price from 9.1 cents per kilowatthour in 2015 to 10.4 cents per kilowatthour in 2030. IER and IHSGI show declining electricity prices between 2015 and 2030. In contrast, EVA shows higher prices than the other projections, with substantial increases between 2015 and 2030.

Total generation and imports of electricity in 2015 are lower in the EVA projections than in the *AEO2009* reference case, IHSGI, and IER projections. U.S. electricity generation in the IER projection (which excludes imports of electricity) is higher than in the other projections. Requirements for generating capacity are based on growth in electricity sales and the need to replace existing units that are uneconomical or are being retired for other reasons. Consistent with its projections of electricity sales, IER shows higher growth in generating capacity through 2015 than in the other projections.

Although the projections for coal-fired capacity in 2030 are similar (with EVA being somewhat lower than the others), there are significant differences in other capacity types. IHSGI and IER project similar levels of oil- and natural-gas-fired capacity, and both are significantly lower than projected in the *AEO2009* reference case. The EVA and IER projections for nuclear capacity are also much higher than the *AEO2009* and IHSGI projections. Nuclear capacity in 2030 is 113 gigawatts in *AEO2009* and 119 gigawatts in the IHSGI projections, as a result of the incentives included in EPACT2005. EVA and IER project substantially more aggressive nuclear growth, with total nuclear capacity at 166 and 154 gigawatts, respectively, in 2030. The *AEO2009* reference case includes 3.4 gigawatts of uprates for nuclear capacity and 4.4 gigawatts of nuclear plant retirements by 2030 as their operating licenses expire. The 2030 projections for renewable capacity also differ widely among the projections, from EVA's 128 gigawatts to IER's 312 gigawatts.

Environmental regulations are an important factor in the selection of technologies for electricity generation. The *AEO2009* reference case excludes the impact of the EPA's CAIR and CAMR regulations, and because only current laws and regulations as of November 2008 are included, it does not assume any tax on CO_2 emissions. Restrictions on CO_2 emissions could change the mix of technologies used to generate electricity.

Natural Gas

In the *AEO2009* reference case, total natural gas consumption declines in the short run (2008-2011), begins rising in 2014, peaks in 2025, then declines from 2025 to 2030 as consumption for electricity generation falls (Table 19). In the projections from other organizations, IHSGI, EVA, and Altos show steady increases in natural gas consumption (although the Altos projection includes an early decline, similar to that in the *AEO2009* reference case). EVA projects the highest level of consumption in 2030 (29.4 trillion cubic feet), followed by Altos (28.1 trillion cubic feet). In contrast, Deutsche Bank AG (DB), IER, and Strategic Energy and Economic Research, Inc. (SEER) show a peak in consumption around 2015 and a

Table 18. Comparison of electricity projections, 2015 and 2030 (billion kilowatthours, except where noted)

Projection	2007	AEO2009 reference case	Other projections		
			IHSGI	EVA	IER
		2015			
Average end-use price (2007 cents per kilowatthour)	***9.1***	***9.1***	***9.9***	***10.7***	***NA***
Residential	*10.6*	*10.8*	*11.4*	*NA*	*9.6*
Commercial	*9.6*	*9.3*	*10.4*	*NA*	*9.6*
Industrial	*6.4*	*6.3*	*6.9*	*NA*	*7.4*
Total generation plus imports	***4,190***	***4,398***	***4,589***	***4,174***	***4,696***
Coal	*2,021*	*2,121*	*2,139*	*1,975*	*NA*
Oil	*66*	*57*	*54*	*58*	*NA*
Natural gas [a]	*892*	*815*	*1,004*	*889*	*NA*
Nuclear	*806*	*831*	*838*	*840*	*NA*
Hydroelectric/other [b]	*374*	*555*	*537*	*420*	*NA*
Net imports	*31*	*17*	*17*	*21*	*NA*
Electricity sales	***3,747***	***3,960***	***4,138***	***NA***	***4,475***
Residential	*1,392*	*1,423*	*1,559*	*NA*	*1,567*
Commercial/other [c]	*1,349*	*1,513*	*1,508*	*NA*	*1,649*
Industrial	*1,006*	*1,025*	*1,071*	*NA*	*1,259*
Capability, including CHP (gigawatts) [d]	***996***	***1,050***	***1,030***	***1,084***	***1,117***
Coal	*315*	*331*	*323*	*331*	*287*
Oil and natural gas	*448*	*458*	*441*	*488*	*510*
Nuclear	*101*	*104*	*105*	*105*	*111*
Hydroelectric/other	*131*	*157*	*160*	*115*	*208*
		2030			
Average end-use price (2007 cents per kilowatthour)	***9.1***	***10.4***	***9.4***	***12.3***	***NA***
Residential	*10.6*	*12.2*	*10.8*	*NA*	*8.6*
Commercial	*9.6*	*10.6*	*10.0*	*NA*	*8.6*
Industrial	*6.4*	*7.4*	*6.4*	*NA*	*6.5*
Total generation plus imports	***4,190***	***5,181***	***5,229***	***4,871***	***5,335***
Coal	*2,021*	*2,415*	*2,356*	*2,006*	*NA*
Oil	*66*	*60*	*40*	*46*	*NA*
Natural gas [a]	*892*	*1,012*	*1,035*	*968*	*NA*
Nuclear	*806*	*907*	*921*	*1,324*	*NA*
Hydroelectric/other [b]	*374*	*758*	*864*	*535*	*NA*
Net imports	*31*	*28*	*14*	*19*	*NA*
Electricity sales	***3,747***	***4,609***	***4,717***	***NA***	***5,064***
Residential	*1,392*	*1,667*	*1,829*	*NA*	*1,891*
Commercial/other [c]	*1,349*	*1,865*	*1,735*	*NA*	*1,963*
Industrial	*1,006*	*1,077*	*1,152*	*NA*	*1,210*
Capability, including CHP (gigawatts) [d]	***996***	***1,227***	***1,102***	***1,171***	***1,224***
Coal	*315*	*360*	*348*	*332*	*349*
Oil and natural gas	*448*	*563*	*403*	*501*	*409*
Nuclear	*101*	*113*	*119*	*166*	*154*
Hydroelectric/other	*131*	*191*	*232*	*128*	*312*

[a]Includes supplemental gaseous fuels. For EVA, represents total oil and natural gas. [b]"Other" includes conventional hydroelectric, pumped storage, geothermal, wood, wood waste, municipal waste, other biomass, solar and wind power, batteries, chemicals, hydrogen, pitch, purchased steam, sulfur, petroleum coke, and miscellaneous technologies. [c]"Other" includes sales of electricity to government, railways, and street lighting authorities. [d]EIA capacity is net summer capability, including combined heat and power plants. IHSGI capacity is nameplate, excluding cogeneration plants.

CHP = combined heat and power. NA = not available.

Sources: ***2007 and AEO2009:*** AEO2009 National Energy Modeling System, run AEO2009.D120908A. **IHSGI:** IHS Global Insight, Inc., *Global Petroleum Outlook, Fall 2008* (Lexington, MA, November 2008). **EVA:** Energy Ventures Analysis, Inc., *FUELCAST: Long-Term Outlook* (August 2008). **IER:** Institute of Energy Economics and the Rational Use of Energy at the University of Stuttgart, TIAM Global Energy System Model (November 2008).

steady decline thereafter. IER projects the lowest level of consumption in 2030 (21.4 trillion cubic feet), followed by DB (23.8 trillion cubic feet).

There are some notable variations across the projections for natural gas consumption by sector. For the residential sector, only Altos shows a decline in consumption in the later years of the projection, with residential natural gas use in 2030 lower than in 2007. DB projects the greatest increase in residential natural gas consumption, with 2030 consumption 1.3 trillion cubic feet higher than in 2007. *AEO2009* shows the smallest increase, with 2030 consumption 0.2 trillion cubic feet higher than in 2007.

For natural gas use in the commercial sector there is significant variation among the projections. Most show consumption increasing over the projection period, with the notable exceptions of DB and IER. As a result, there is a significant range among the projections for 2030, with Altos showing an increase of 0.7 trillion cubic feet from 2007 (slightly higher than the

Table 19. Comparison of natural gas projections, 2015, 2025, and 2030 (trillion cubic feet, except where noted)

Projection	2007	AEO2009 reference case	Other projections					
			IHSGI	EVA	DB	IER	SEER	Altos
					2015			
Dry gas production [a]	**19.30**	**20.31**	**21.93**	**20.35**	**21.96**	**15.64**	**22.13**	**20.40**
Net imports	**3.79**	**2.36**	**3.01**	**3.74**	**5.02**	**10.75**	**3.55**	**5.54**
Pipeline	3.06	1.11	1.41	1.98	2.83	5.01	1.80	1.34
LNG	0.73	1.25	1.60	1.76	2.19	5.74	1.75	4.20
Consumption	**23.05**	**22.77**	**24.92**	**25.56**	**26.21**	**26.39**	**25.68**	**22.55 [b]**
Residential	4.72	4.87	5.08	5.07	5.22	5.28	4.91	4.22
Commercial	3.01	3.16	3.14	3.08	3.34	2.28	3.27	2.87
Industrial [c]	6.63	6.80	6.97	7.38	7.26	5.35	6.58	6.30 [d]
Electricity generators [e]	6.87	6.04	7.63	8.05	8.38	8.83	9.03	9.15
Other [f]	1.81	1.90	2.11	1.98	2.01	4.65	1.89	NA
Lower 48 wellhead price (2007 dollars per thousand cubic feet) [g]								
	6.39	**6.27**	**8.73**	**6.16**	**7.80**	7.38	**6.85**	**7.47**
End-use prices (2007 dollars per thousand cubic feet)								
Residential	13.05	12.32	14.49	NA	NA	12.58	12.76	NA
Commercial	11.30	10.86	13.06	NA	NA	11.28	11.23	NA
Industrial [h]	7.73	7.21	10.67	NA	NA	9.86	8.15	NA
Electricity generators	7.22	6.90	9.40	NA	NA	8.16	7.74	NA
					2025			
Dry gas production [a]	**19.30**	**23.22**	**22.07**	**18.75**	**19.75**	**14.51**	**21.32**	**18.80**
Net imports	**3.79**	**1.35**	**3.51**	**8.50**	**5.36**	**7.76**	**3.24**	**9.50**
Pipeline	3.06	0.15	0.91	2.91	1.83	2.02	0.56	0.30
LNG	0.73	1.20	2.60	5.58	3.53	5.74	2.68	9.20
Consumption	**23.05**	**24.67**	**25.56**	**27.41**	**24.83**	**22.27**	**24.56**	**26.06 [b]**
Residential	4.72	4.99	5.31	5.31	5.76	5.40	4.95	4.10
Commercial	3.01	3.36	3.18	3.14	2.73	2.23	3.50	3.09
Industrial [c]	6.63	6.76	7.36	8.16	5.92	4.28	6.64	6.60 [d]
Electricity generators [e]	6.87	7.38	7.55	8.69	8.59	5.47	7.49	12.27
Other [f]	1.81	2.19	2.17	2.11	1.82	4.88	1.99	NA
Lower 48 wellhead price (2007 dollars per thousand cubic feet) [g]								
	6.39	**7.33**	**7.47**	**7.20**	**9.45**	**8.17**	**7.25**	**9.21**
End-use prices (2007 dollars per thousand cubic feet)								
Residential	13.05	13.43	13.02	NA	NA	13.37	13.35	NA
Commercial	11.30	12.07	11.63	NA	NA	12.07	11.56	NA
Industrial [h]	7.73	8.22	9.35	NA	NA	10.77	8.55	NA
Electricity generators	7.22	7.95	8.10	NA	NA	8.95	8.06	NA

NA = not available. See notes and sources at end of table.

AEO2009 projection) and DB showing a decrease of 0.7 trillion cubic feet.

The range of projections for natural gas consumption in the industrial sector is similar to that for the commercial sector. Only DB and IER show declines from 2007 to 2030. Whereas EVA shows an increase of 2.0 trillion cubic feet, IER shows a decrease of 3.2 trillion cubic feet.

Natural gas consumption in the electricity generation sector grows steadily from 2007 to 2015 in all the projections, with the exception of a projected decline in the *AEO2009* reference case from 6.9 trillion cubic feet in 2007 to 6.0 trillion cubic feet in 2015. IHSGI, EVA, DB, and Altos show greater reliance on natural gas for electricity generation than the *AEO2009* projection. The largest increase from 2007 to 2030 is projected by Altos (5.3 trillion cubic feet), followed by EVA (3.1 trillion cubic feet). *AEO2009* shows an initial decline, followed by an increase and then another decline in the later years of the projection, but is within the range of the other projections.

Sources of natural gas supply also vary among the projections. In all the projections, U.S. pipeline imports in 2030 are lower than in 2007, although IER projects an initial increase in net pipeline imports from 2007 to 2015. The size of the decline in pipeline imports is similar in the *AEO2009*, IHSGI, SEER, and Altos projections, whereas DB shows a smaller but steady decrease. The IER projection for 2030 is similar to the DB projection, although there are differences between the two in the years from 2007 to 2025. EVA shows an initial decline in natural gas pipeline imports, followed by a recovery and a

Table 19. Comparison of natural gas projections, 2015, 2025, and 2030 (continued)
(trillion cubic feet, except where noted)

Projection	2007	AEO2009 reference case	Other projections					
			IHSGI	EVA	DB	IER	SEER	Altos
		2030						
Dry gas production [a]	**19.30**	**23.60**	**22.33**	**18.49**	**18.70**	**13.76**	**20.44**	**17.70**
Net imports	**3.79**	**0.66**	**3.56**	**9.17**	**5.39**	7.64	**3.74**	**11.01**
Pipeline	3.06	-0.18	0.51	2.49	1.83	1.97	0.32	0.01
LNG	0.73	0.85	3.05	6.68	3.56	5.68	3.42	11.00
Consumption	**23.05**	**24.36**	**25.87**	**29.41**	**23.81**	**21.41**	**24.18**	**28.13 [b]**
Residential	4.72	4.93	5.39	5.43	6.06	5.60	4.92	4.63
Commercial	3.01	3.44	3.23	3.17	2.35	2.50	3.66	3.69
Industrial [c]	6.63	6.85	7.32	8.60	5.09	3.42	6.62	7.61 [d]
Electricity generators [e]	6.87	6.93	7.75	9.94	8.59	4.36	6.98	12.20
Other [f]	1.81	2.21	2.19	2.27	1.73	5.52	1.99	NA
Lower 48 wellhead price (2007 dollars per thousand cubic feet) [g]								
	6.39	**8.40**	**7.61**	**7.78**	**9.94**	**8.88**	**7.28**	**10.13**
End-use prices (2007 dollars per thousand cubic feet)								
Residential	13.05	14.71	13.06	NA	NA	14.08	13.48	NA
Commercial	11.30	13.32	11.70	NA	NA	12.78	11.56	NA
Industrial [h]	7.73	9.33	9.47	NA	NA	11.48	8.57	NA
Electricity generators	7.22	8.94	8.23	NA	NA	9.66	8.31	NA

NA = not available.
[a]Does not include supplemental fuels. [b]Does not include natural gas use as fuel for lease and plants, pipelines, or natural gas vehicles. [c]Includes consumption for industrial CHP plants, a small number of electricity-only plants, and GTL plants for heat and power production; excludes consumption by nonutility generators. [d]Includes lease and plant fuel. [e]Includes consumption of energy by electricity-only and CHP plants whose primary business is to sell electricity, or electricity and heat, to the public. Includes electric utilities, small power producers, and exempt wholesale generators. [f]With the exception of IHSGI and IER, includes lease, plant, and pipeline fuel and fuel consumed in natural gas vehicles. IHSGI includes lease and plant fuel with industrial consumption. IER includes agricultural and non-energy use in other consumption. [g]2007 wellhead natural gas prices for EVA and DB are $6.68 and $6.91 per thousand cubic feet, respectively. [h]The 2007 industrial natural gas prices for IHSGI and SEER are $8.56 and $7.59 per thousand cubic feet, respectively.

Sources: **2007 and *AEO2009*:** AEO2009 National Energy Modeling System, run AEO2009.D120908A. **IHSGI:** IHS Global Insight, Inc., *2008 U.S. Energy Outlook* (September 2008). **EVA:** Energy Ventures Analysis, Inc., *FUELCAST: Long-Term Outlook* (January 2009). **DB:** Deutsche Bank AG estimates (September 2008). **IER:** Institute of Energy Economics and the Rational Use of Energy at the University of Stuttgart, TIAM Global Energy System Model (November 2008). **SEER:** Strategic Energy and Economic Research, Inc., "SEER Balanced Portfolio, $45 per ton Carbon Tax 2015" (April 2008). **Altos:** Altos World Gas Trade Model (October 2008).

subsequent decline, with total pipeline imports in 2030 at the highest level among all the projections but still 0.6 trillion cubic feet below the 2007 level.

Net LNG imports in the *AEO2009* reference case are considerably lower than in any of the other projections, at less than 1.0 trillion cubic feet in 2030. EVA and IER are far more optimistic about the potential for increased LNG imports, with 2030 levels near 6 trillion cubic feet. Altos projects the highest level of LNG imports, at 11.0 trillion cubic feet in 2030, and IHSGI, DB, and SEER project more modest increases.

U.S. domestic natural gas production increases through 2015 in all the projections except IER's. SEER shows the highest production levels in 2015, at 22.1 trillion cubic feet. After 2015, only IHSGI and *AEO2009* show domestic production continuing to increase through 2030. The domestic production share of total natural gas supply in the *AEO2009* reference case increases steadily, to more than 95 percent in 2030, as compared with the DB projection, which shows the domestic share consistent at around 80 percent. The other projections show declines in domestic natural gas production from 2015 to 2030. IER has the lowest level in 2030, at 13.8 trillion cubic feet. In the EVA, IER, and Altos projections, domestic production represents a much smaller share of total natural gas supply in 2030, at less than 70 percent.

Natural gas wellhead prices in the United States, which were $6.39 per thousand cubic feet in 2007, increase steadily in all the projections, with some exceptions in 2015. Altos, IER, and DB project higher average prices in 2030 than *AEO2009*. IHSGI, EVA, and SEER project lower prices than *AEO2009*. SEER and Altos also include lower domestic production levels than the other projections. The highest wellhead price in 2030 is projected by Altos, at $10.13 per thousand cubic feet. The lowest is projected by SEER, at $7.28 per thousand cubic feet.

The price margins for delivered natural gas (the difference between delivered and wellhead prices) can vary significantly from year to year. In 2007, margins in the end-use sectors were notably higher than the historical average. In the *AEO2009* reference case, margins in the electricity generation and industrial sectors generally decline over the projection period, whereas margins in the residential and commercial sectors generally rise, because fixed costs are spread over lower per-customer volumes as consumption is reduced by efficiency improvements.

End-use prices in the IHSGI projection imply declining margins in all end-use sectors. The IER projections imply constant margins in all sectors except the industrial sector. In the SEER projection, margins remain relatively steady in the residential and industrial sectors through 2030. The industrial sector margins in the SEER projection are approximately $0.40 per thousand cubic feet higher than those in the *AEO2009* projection from 2015 to 2030, and those in the IER projection are about $1.65 per thousand cubic feet higher than in *AEO2009*. Margins in the electricity generation sector are similar in the *AEO2009* and IHSGI projections, and both are lower than in the IER and SEER projections.

Liquid Fuels

In the *AEO2009* reference case, the world oil price is $111 per barrel in 2015 and rises to $130 per barrel in 2030 (see Table 16). In the DB projection, real crude oil prices are $72 per barrel in 2015, $68 per barrel in 2025, and $70 per barrel in 2030. Not surprisingly, domestic crude oil production is lower and total net imports are higher in the DB projections than in *AEO2009* (Table 20).

A major difference between the *AEO2009* reference case and all but one of the other projections—IHSGI, DB, IER, Purvin and Gertz, Inc. (P&G), and IEA—is that the other projections assume less domestic crude oil production and a gradual decline in production in future years. The IER projection for oil production is particularly pessimistic in comparison with *AEO2009*. In general, the more pessimistic outlook in the other projections results in higher levels of total net imports and greater dependence on imports to meet supply needs. The one exception is EVA, which includes higher domestic crude oil production in 2015 than projected in the *AEO2009* reference case; however, EVA's projections for crude oil and natural gas liquids (NGL) production in 2025 and 2030 are lower than in *AEO2009*.

The *AEO2009* reference case is also the most bullish with respect to NGL production, with the exception of IHSGI. Both IER and DB show lower NGL production than *AEO2009*, with IER being much lower. The difference can be explained, at least in part, by lower projections of natural gas production in the DB and IER cases. Both projections show a steady decline in natural gas production after 2020 (earlier in the IER case), whereas *AEO2009* shows a slow but steady increase through 2030. The highest projection for U.S.

Table 20. Comparison of liquids projections, 2015, 2025, and 2030
(million barrels per day, except where noted)

Projection	2007	AEO2009 reference case	Other projections					
			IHSGI	EVA	DB	IER	P&G	IEA
		2015						
Crude oil and NGL production	**6.85**	**7.61**	**6.60**	**8.15**	**6.74**	**5.08**	**NA**	**6.80**
Crude oil	5.07	5.72	4.56	6.39	5.04	4.29	4.36	NA
Natural gas liquids	1.78	1.89	2.02	1.76	1.70	0.78	NA	NA
Total net imports	**12.09**	**9.74**	**12.11**	**NA**	**11.38**	**12.97**	**11.48**	**NA**
Crude oil	10.00	8.10	11.10	NA	NA	NA	11.68	NA
Petroleum products	2.09	1.64	1.02	NA	NA	NA	-0.20	NA
Petroleum demand	**20.65**	**20.16**	**21.07**	**NA**	**19.69**	**18.05**	**18.28**	**18.75**
Motor gasoline	9.29	8.97	9.09	NA	9.01	7.57	8.99	NA
Jet fuel	1.63	1.52	1.72	NA	1.52	1.99	1.59	NA
Distillate fuel	4.20	4.46	4.55	NA	4.00	3.49	4.23	NA
Residual fuel	0.72	0.69	0.69	NA	0.60	0.64	0.51	NA
Other	4.82	4.52	5.02	NA	4.56	4.36	2.96	NA
Net import share of petroleum demand (percent)	**59**	**49**	**57**	**NA**	**58**	**72**	**63**	**NA**
		2025						
Crude oil and NGL production	**6.85**	**9.14**	**5.74**	**7.05**	**5.28**	**3.80**	NA	**NA**
Crude oil	5.07	7.21	3.71	5.61	4.01	3.07	3.24	NA
Natural gas liquids	1.78	1.93	2.03	1.44	1.27	0.73	NA	NA
Total net imports	**12.09**	**8.01**	**12.61**	**NA**	**13.88**	**15.58**	**12.51**	**NA**
Crude oil	10.00	6.66	12.06	NA	NA	NA	12.37	NA
Petroleum products	2.09	1.35	0.56	NA	NA	NA	0.14	NA
Petroleum demand	**20.65**	**20.76**	**21.77**	**NA**	**21.05**	**19.37**	**18.15**	**NA**
Motor gasoline	9.29	8.15	8.12	NA	9.59	7.89	7.82	NA
Jet fuel	1.62	1.81	2.04	NA	1.62	2.28	1.78	NA
Distillate fuel	4.20	4.91	5.61	NA	4.36	4.00	4.92	NA
Residual fuel	0.72	0.71	0.65	NA	0.63	0.74	0.42	NA
Other	4.82	5.18	5.35	NA	4.85	4.46	3.22	NA
Net import share of petroleum demand (percent)	**59**	**40**	**58**	**NA**	**66**	**80**	**63**	**NA**
		2030						
Crude oil and NGL production	**6.85**	**9.29**	**5.36**	**6.28**	**4.78**	**3.15**	**NA**	**6.50**
Crude oil	5.07	7.37	3.30	4.97	3.63	2.45	2.84	NA
Natural gas liquids	1.78	1.92	2.06	1.31	1.15	0.70	NA	NA
Total net imports	**12.09**	**8.35**	**13.49**	**NA**	**14.99**	**16.53**	**12.80**	**NA**
Crude oil	10.00	6.95	12.46	NA	NA	NA	12.66	NA
Petroleum products	2.09	1.40	1.02	NA	NA	NA	0.15	NA
Petroleum demand	**20.65**	**21.67**	**22.27**	**NA**	**21.69**	**19.69**	**18.15**	**18.41**
Motor gasoline	9.29	8.04	7.65	NA	9.83	8.10	7.45	NA
Jet fuel	1.62	1.99	2.21	NA	1.66	2.17	1.85	NA
Distillate fuel	4.20	5.42	6.26	NA	4.58	4.29	5.14	NA
Residual fuel	0.72	0.72	0.64	NA	0.65	0.79	0.40	NA
Other	4.82	5.50	5.51	NA	4.97	4.34	3.30	NA
Net import share of petroleum demand (percent)	**59**	**41**	**61**	**NA**	**69**	**84**	**71**	**NA**

NA = Not available.

Sources: ***2007 and AEO2009:*** AEO2008 National Energy Modeling System, run AEO2009.D120908A. **IHSGI:** IHS Global Insight, Inc., *Global Petroleum Outlook, Fall 2008* (Lexington, MA, November 2008). **EVA:** Energy Ventures Analysis, Inc., *FUELCAST: Long-Term Outlook* (January 2009). **DB:** Deutsche Bank AG, e-mail from Adam Sieminski on November 4, 2008. **IER:** Institute of Energy Economics and the Rational Use of Energy at the University of Stuttgart, e-mail from Markus Blesl on December 1, 2008. **P&G:** Purvin and Gertz, Inc., *2008 Global Petroleum Market Outlook* (February 2009). **IEA:** International Energy Agency, *World Energy Outlook 2008* (Paris, France, November 2008).

NGL production is by IHSGI, consistent with its outlook for a significant increase in natural gas production through 2015, to a level higher than the *AEO2009* projection for 2015. *AEO2009* projects more natural gas production in 2025 and 2030 than in the IHSGI projection, however, suggesting that IHSGI assumes higher yields of NGL from the production of natural gas.

With the exception of IEA and P&G, liquids demand is similar in all the projections. The IEA petroleum demand projection is lower than the others, possibly reflecting IEA's assumptions of generally higher prices for oil and petroleum products, which depress demand and create an incentive for more use of alternative fuels and improvements in fuel efficiency. The IEA projection also includes more pessimistic assumptions about U.S. (and worldwide) economic growth. Although P&G projects a lower oil price than the *AEO2009* reference case, the lower GDP growth rate in the P&G projection leads to significantly lower demand in all categories in the later years of the projections.

Both the DB and IER cases show increasing demand for motor gasoline in the long term. In the *AEO2009* reference case, motor gasoline demand declines as a result of new CAFE standards and a steady increase in ethanol supply throughout the projection. Demand for gasoline also falls in the IHSGI projection, in large part because of its optimistic projection for ethanol consumption, at 2.02 million barrels per day (31 billion gallons per year) of ethanol in 2030.

Demand for distillate fuel increases throughout all the projections, presumably because of rapid growth in freight and ship movement, leading to increased consumption of diesel fuel, during the economic recovery. Jet fuel demand also increases from 2015 to 2030 in all the projections except IER.

Coal

The outlook for coal markets varies considerably across the projections compared in Table 21. Differences in assumptions about expectations for and implementation of legislation aimed at reducing GHG emissions can lead to significantly different projections for coal production, consumption, and prices. In addition, different assumptions about world oil prices, natural gas prices, and economic growth can contribute to variation across the projections.

In the *AEO2009* reference case, total U.S. coal consumption increases to 1,363 million tons (26.6 quadrillion Btu) in 2030. Total coal consumption also increases in the IEA projection, to 25.1 quadrillion Btu in 2030, which is closer to the *AEO2009* projection than are any of the others. Total coal consumption decreases from 2007 levels to 991 million tons and 21.4 quadrillion Btu in 2030 in the IER and DB projections, respectively. IHSGI projects relatively constant total coal consumption over the projection period, with a slight overall increase from 2007 levels to 1,150 million tons in 2030.

In the *AEO2009* projection, coal production increases to 1,248 milliion tons (25.1 quadrillion Btu) in 2025 and 1,341 million tons (26.9 quadrillion Btu) in 2030. Similar increases are projected by IEA and Hill and Associates (WM), to 27.3 quadrillion Btu in 2030 and 1,361 million tons in 2025, respectively. Coal production falls slightly from 2007 levels in the IER projection, to 1,035 million tons in 2030. In the IHSGI projection, production remains relatively constant, increasing slightly to 1,158 million tons in 2030.

With the exception of IER and WM, the other projections show net U.S. coal exports as flat or decreasing. In the *AEO2009* reference case, the United States becomes a net importer of coal, with coal exports declining to 44 million tons and imports increasing to 53 million tons in 2030. The IHSGI and IER projections show net U.S. exports in 2030 at 9 million tons and 44 million tons, respectively, with IER's projection of 72 million tons of coal exports in 2030 the highest among all the projections.

Minemouth coal prices in 2030 are higher than in 2007 in all the projections except IHSGI. *AEO2009* shows the minemouth price increasing to $28.45 per ton ($1.42 per million Btu) in 2025 and $29.10 per ton ($1.46 per million Btu) in 2030, compared with $34.43 per ton ($1.66 per million Btu) in 2030 projected by IER and $32.26 per ton ($1.62 per million Btu) in 2025 projected by WM. In the IHSGI projection, the minemouth coal price falls to $21.63 per ton ($1.05 per million Btu) in 2030.

Table 21. Comparison of coal projections, 2015, 2025, and 2030 (million short tons, except where noted)

Projection	2007	AEO2009 reference case	Other projections				
			IHSGI	DB	IER	IEA	WM
			2015				
Production	1,147	1,206	1,167	NA	896	24.8 [a]	1,225 [b]
Consumption by sector							
Electric power	1,046	1,096	1,069	NA	752	NA	NA
Coke plants	23	20	22	NA	37	NA	NA
Coal-to-liquids	0	17	NA	NA	28	NA	NA
Other industrial/buildings	60	60	59	NA	73	NA	NA
Total	1,129	1,192	1,150	23.0 [a]	890	23.0 [a]	NA
Net coal exports	25	28	17	NA	6	NA	16
Exports	59	65	57	NA	33	NA	37
Imports	34	38	40	NA	27	NA	22
Minemouth price							
(2007 dollars per short ton)	25.82	28.71	23.79 [c]	NA	34.43 [d]	NA	32.27 [d]
(2007 dollars per million Btu)	1.27	1.42	1.15	NA	1.66 [d]	NA	1.61 [d]
Average delivered price to electricity generators							
(2007 dollars per short ton)	35.45	38.47	37.47 [c]	NA	42.30 [d]	NA	49.24 [d]
(2007 dollars per million Btu)	1.78	1.94	1.81	NA	2.04 [d]	NA	2.51 [d]
			2025				
Production	1,147	1,248	1,158	NA	1,046	NA	1,361 [a]
Consumption by sector							
Electric power	1,046	1,126	1,071	NA	815	NA	NA
Coke plants	23	18	20	NA	38	NA	NA
Coal-to-liquids	0	48	NA	NA	53	NA	NA
Other industrial/buildings	60	59	56	NA	85	NA	NA
Total	1,129	1,252	1,147	21.9 [a]	991	25.0 [a]	NA
Net coal exports	25	8	10	NA	56	NA	33
Exports	59	53	48	NA	72	NA	52
Imports	34	45	38	NA	16	NA	18
Minemouth price							
(2007 dollars per short ton)	25.82	28.45	22.21 [c]	NA	34.43 [d]	NA	32.26 [d]
(2007 dollars per million Btu)	1.27	1.42	1.07	NA	1.66 [d]	NA	1.62 [d]
Average delivered price to electricity generators							
(2007 dollars per short ton)	35.45	38.83	35.40 [c]	NA	42.30 [d]	NA	50.17 [d]
(2007 dollars per million Btu)	1.78	1.96	1.71	NA	2.04 [d]	NA	2.52 [d]

Btu = British thermal unit. NA = Not available. See notes and sources at end of table.

Table 21. Comparison of coal projections, 2015, 2025, and 2030 (continued)
(million short tons, except where noted)

Projection	2007	AEO2009 reference case	Other projections				
			IHSGI	DB	IER	IEA	WM
		2030					
Production	**1,147**	**1,341**	**1,158**	**NA**	**1,035**	**27.3** [a]	**NA**
Consumption by sector							
Electric power	1,046	1,215	1,077	NA	797	NA	NA
Coke plants	23	18	20	NA	37	NA	NA
Coal-to-liquids	0	70	NA	NA	69	NA	NA
Other industrial/buildings	60	60	53	NA	88	NA	NA
Total	**1,129**	**1,363**	**1,150**	**21.4** [a]	**991**	**25.1** [a]	**NA**
Net coal exports	**25**	**-10**	**9**	**NA**	**44**	**NA**	**NA**
Exports	59	44	46	NA	72	NA	NA
Imports	34	53	38	NA	27	NA	NA
Minemouth price							
(2007 dollars per short ton)	25.82	29.10	21.63 [c]	NA	34.43 [d]	NA	NA
(2007 dollars per million Btu)	1.27	1.46	1.05	NA	1.66 [d]	NA	NA
Average delivered price to electricity generators							
(2007 dollars per short ton)	35.45	40.61	34.90 [c]	NA	42.30 [d]	NA	NA
(2007 dollars per million Btu)	1.78	2.04	1.69	NA	2.04 [d]	NA	NA

Btu = British thermal unit. NA = Not available.
[a]Reported in quadrillion Btu.
[b]Reported in thermal thousand tons; does not include petroleum coke or waste coal.
[c]Imputed, using heat conversion factor implied by U.S. steam coal consumption figures for the electricity sector.
[d]Converted to 2007 dollars, using the *AEO2009* GDP inflator.

Sources: ***2007 and AEO2009:*** AEO2009 National Energy Modeling System, run AEO2009.D120908A. **IHSGI:** IHS Global Insight, Inc., *2008 U.S. Energy Outlook* (September 2008). **DB:** Deutsche Bank AG, e-mail from Adam Sieminski on November 4, 2008. **IER:** Institute of Energy Economics and the Rational Use of Energy at the University of Stuttgart, TIAM Global Energy System Model (November 2008). **IEA:** International Energy Agency, *World Energy Outlook 2008* (Paris, France, November 2008).**WM:** Hill and Associates, a Wood Mackenzie Company, *Fall 2008 Long Term Outlook Base Case* and *2008 International Coal Trade Base Case*.

List of Acronyms

A.B.	Assembly Bill
ACP	Alternative compliance payment
AD	Associated-dissolved (natural gas)
AEO	*Annual Energy Outlook*
AEO2008	*Annual Energy Outlook 2008*
AEO2009	*Annual Energy Outlook 2009*
ANWR	Arctic National Wildlife Refuge
ARRA2009	American Recovery and Reinvestment Act of 2009
BLS	Bureau of Labor Statistics
BTL	Biomass-to-liquids
Btu	British thermal unit
CAA	Clean Air Act
CAFE	Corporate Average Fuel Economy
CAIR	Clean Air Interstate Rule
CAMR	Clean Air Mercury Rule
CARB	California Air Resources Board
CBO	Congressional Budget Office
CCS	Carbon capture and storage
CERA	Cambridge Energy Research Associates
CHP	Combined heat and power
CNG	Compressed natural gas
CO_2	Carbon dioxide
CREB	Clean and Renewable Energy Bonds
CTL	Coal-to-liquids
CZMA	Coastal Zone Management Act of 1972
DB	Deutsche Bank AG
DOE	U.S. Department of Energy
DOER	State Department of Energy Resources (Massachusetts)
DOJ	U.S. Department of Justice
E85	Fuel containing a blend of 70 to 85 percent ethanol and 30 to 15 percent gasoline by volume
EIA	Energy Information Administration
EIEA2008	Energy Improvement and Extension Act of 2008
EISA2007	Energy Independence and Security Act of 2007
EOR	Enhanced oil recovery
EPA	U.S. Environmental Protection Agency
EPACT2005	Energy Policy Act of 2005
EPACT92	Energy Policy Act of 1992
EVA	Energy Ventures Analysis, Inc.
FAME	Fatty acid methyl ester
FFV	Flex-fuel vehicle
FGD	Flue gas desulfurization
GDP	Gross domestic product
GHG	Greenhouse gas
GTL	Gas-to-liquids
GVWR	Gross vehicle weight rating
HEV	Hybrid electric vehicle
H.R.	House of Representatives
ICE	Internal combustion engine
IEA	International Energy Agency
IER	Institute of Energy Economics and the Rational Use of Energy at the University of Stuttgart
IHSGI	IHS Global Insight
INFORUM	Interindustry Forecasting Project at the University of Maryland
IRP	Integrated resource plan
IRR	Internal rate of return
ITC	Investment tax credit
LCFS	Low Carbon Fuel Standard (California)
LDV	Light-duty vehicle
Li-Ion	Lithium-ion
LNG	Liquefied natural gas
LPG	Liquid petroleum gas
MHEV	Micro hybrid electric vehicle
MMS	Minerals Management Service
mpg	Miles per gallon
MSAT2	Mobile Source Air Toxics Rule (February 2007)
MTBE	Methyl tertiary butyl ether
MY	Model year
NA	Nonassociated (natural gas)
NAAQS	National Ambient Air Quality Standards
NAECA	National Appliance Energy Conservation Act
NEMS	National Energy Modeling System (EIA)
NGL	Natural gas liquids
NHTSA	National Highway Traffic Safety Administration
NiMH	Nickel metal hydride
NO_x	Nitrogen oxide
OCS	Outer Continental Shelf
OCSLA	Outer Continental Shelf Lands Act
OECD	Organization for Economic Cooperation and Development
OMB	Office of Management and Budget
OPEC	Organization of the Petroleum Exporting Countries
P.L.	Public Law
P&G	Purvin and Gertz, Inc.
PHEV	Plug-in hybrid electric vehicle
PHEV-10	PHEV designed to travel about 10 miles on battery power alone
PHEV-20	PHEV designed to travel about 20 miles on battery power alone
PHEV-40	PHEV designed to travel about 40 miles on battery power alone
$PM_{2.5}$	Particulate matter with a diameter less than or equal to 2.5 microns
PTC	Production tax credit
PV	Solar photovoltaic
REC	Renewable energy credit
RFG	Reformulated gasoline
RFS	Renewable fuels standard
RGGI	Regional Greenhouse Gas Initiative
RPS	Renewable portfolio standard
SCR	Selective catalytic control equipment
SEER	Strategic Energy and Economic Research, Inc.
SLA	Submerged Lands Act
SO_2	Sulfur dioxide
SSA	Social Security Administration
TAPS	Trans Alaska Pipeline System
WCI	Western Climate Initiative
WM	Hill and Associates, a Wood Mackenzie Company
WTI	West Texas Intermediate (crude oil)

Notes and Sources

Table Notes and Sources

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

Table 1. Estimated fuel economy for light-duty vehicles, based on proposed CAFE standards, 2010-2015: National Highway Traffic Safety Administration, *Average Fuel Economy Standards: Passenger Cars and Light Trucks Model Years 2011-2015*, Notice of Proposed Rulemaking, 49 CFR Parts 523, 531, 533, 534, 536, and 537 [Docket No. NHTSA 2008-2009], RIN 2127-AK29 (Washington, DC, April 2008), pp. 14-15, web site www.nhtsa.dot.gov/portal/site/nhtsa/menuitem.43ac99aefa80569eea57529cdba046a0.

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Table 3. State renewable portfolio standards: Energy Information Administration, Office of Integrated Analysis and Forecasting. Based on a review of enabling legislation and regulatory actions from the various States of policies identified by the Database of State Incentives for Renewable Energy (web site www.dsireuse.org) as of November 2008.

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Table 5. Liquid fuels production in three cases, 2007 and 2030: AEO2009 National Energy Modeling System, runs AEO2009.D120908A, LP2009.D122308A, and HP2009.D121108A.

Table 6. Assumptions used in comparing conventional and plug-in hybrid electric vehicles: Energy Information Administration, Office of Integrated Analysis and Forecasting.

Table 7. Conventional vehicle and plug-in hybrid system component costs for mid-size vehicles at volume production: Electric Power Research Institute, *Advanced Batteries for Electric-Drive Vehicles*, 1009299 (Palo Alto, CA, May 2004), web site www.spinnovation.com/sn/Batteries/Advanced_Batteries_for_Electric-Drive_Vehicles.pdf. Note that this is one cost estimate among several that were used in the analysis and that PHEV system costs increase as the all-electric range of the vehicle increases.

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Table 9. Crude oil and natural gas production and prices in two cases, 2020 and 2030: Tables A12, A14, and D14.

Table 10. Estimated recoverable resources from oil shale in Colorado, Utah, and Wyoming: U.S. Department of Energy, *Strategic Significance of America's Oil Shale Resource, Volume II, Oil Shale Resources, Technology, and Economics* (Office of Naval Petroleum and Oil Shale Reserves, Washington, DC, March 2004), pp. 1-5, web site www.fossil.energy.gov/programs/reserves/npr/publications/npr_strategic_significancev2.pdf. Includes natural gas and natural gas liquids, which constitute 15 to 40 percent of the total recoverable Btu content, depending on the specific shale rock characteristics and the process used to extract the oil and natural gas.

Table 11. Assumptions for comparison of three Alaska North Slope natural gas facility options: Gas Conversion Efficiency: LNG facility efficiency does not include any LNG tanker losses while in transit; pipeline efficiency based on averages cited in documentation for the Alaska Gasline Inducement Act, web site http://gov.state.ak.us/agia; LNG and GTL losses based on levels cited in technical literature. Source: B. Patel, *Gas Monetisation: A Techno-Economic Comparison of Gas-To-Liquid and LNG* (Glasgow, Scotland: Foster Wheeler Energy Limited, 2005). **Capital Costs:** Gathering and treatment costs based on ConocoPhilips AGIA proposal costs. LNG capital costs based on liquefaction plant estimates provided by Robert Baron, a DOE Fossil Energy consultant, and prorated AGIA gas pipeline costs based on the mileage from the North Slope to Valdez, and escalated by 20 percent to reflect the cost of building over the Alaska Range mountains in a seismically active zone. GTL North Slope capital cost based on $110,000 per daily stream barrel as cited in K. Nelson, "Legislators Told GTL a No-Go for ANS Gas," *Petroleum News*, Vol. 12, No. 10 (March 11, 2007), web site www.petroleumnews.com/pnads/786285153.shtml. **Operating Costs:** Pipeline operating costs based on EIA's NGTDM model values. LNG operating costs based on study by Robert Baron. GTL operating costs are based on EIA's INGM model.

Table 12. Average crude oil and natural gas prices in three cases, 2011-2020 and 2021-2030: AEO2009 National Energy Modeling System, runs AEO2009.D120908A, LP2009.D122308A, and HP2009.D121108A.

Table 13. Comparison of gasoline and natural gas passenger vehicle attributes: Honda Motors, web site http://automobiles.honda.com (as of February 10, 2009). Data taken from Honda's 2009-civic-sedan-fact.sheet.pdf and 2009-civic-gx-fact.sheet.pdf. Vehicle comparison based on 4-door sedans equipped with automatic transmission. The natural gas vehicle's fuel gallon is "gasoline equivalent gallons" based on 3,600 pounds per square inch of natural gas cylinder pressure.

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Figure Notes and Sources

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

Figure 1. Total liquid fuels demand by sector: History: Energy Information Administration, *Annual Energy Review 2007*, DOE/EIA-0384(2007) (Washington, DC, June 2008). **Projections:** AEO2009 National Energy Modeling System, run AEO2009.D120908A.

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Figure 3. New light-duty vehicle sales shares by type: History, Light Trucks: Energy Information Administration, Office of Integrated Analysis and Forecasting using data from National Highway Traffic Safety Administration. **History, Passenger Cars:** National Highway Traffic Safety Administration, *New Passenger Car Fleet Average Characteristics*, web site www.nhtsa.gov/cars/rules/CAFE/NewPassengerCarFleet.htm. **Projections:** AEO2009 National Energy Modeling System, runs AEO2009.D120908A, NORSK2009.D120908A, and CAP2009.D010909A.

Figure 4. Proposed CAFE standards for passenger cars by vehicle footprint, model years 2011-2015: Energy Information Administration, Office of Integrated Analysis and Forecasting.

Figure 5. Proposed CAFE standards for light trucks by vehicle footprint, model years 2011-2015: Energy Information Administration, Office of Integrated Analysis and Forecasting.

Figure 6. Average fuel economy of new light-duty vehicles in the *AEO2008* and *AEO2009* projections, 1995-2030: History: Energy Information Administration, *Annual Energy Review 2007*, DOE/EIA-0384(2007) (Washington, DC, June 2008). ***AEO2008* Projections:** AEO2008 National Energy Modeling System, run AEO2008.D030208F. ***AEO2009* Projections:** AEO2009 National Energy Modeling System, run AEO2009.D120908A.

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Figure 9. Incremental cost of PHEV purchase with EIEA2008 tax credit included compared with conventional ICE vehicle purchase, by PHEV all-electric driving range, 2010, 2020, and 2030: Energy Information Administration, Office of Integrated Analysis and Forecasting.

Figure 10. PHEV fuel savings and incremental vehicle cost by gasoline price and PHEV all-electric driving range, 2030: Energy Information Administration, Office of Integrated Analysis and Forecasting.

Figure 11. PHEV fuel savings and incremental vehicle cost by gasoline price and PHEV all-electric driving range, 2010 and 2020: Energy Information Administration, Office of Integrated Analysis and Forecasting.

Figure 12. PHEV annual fuel savings per vehicle by all-electric driving range: Energy Information Administration, Office of Integrated Analysis and Forecasting.

Figure 13. U.S. total domestic oil production in two cases, 1990-2030: History: Energy Information Administration, *Annual Energy Review 2007*, DOE/EIA-0384(2007) (Washington, DC, June 2008). **Projections:** AEO2009

National Energy Modeling System, runs AEO2009.D120908A and OCSLIMITED.D120908A.

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Figure 16. Average internal rates of return for three Alaska North Slope natural gas facility options in three cases, 2021-2030: Energy Information Administration, Office of Integrated Analysis and Forecasting.

Figure 17. Ratio of crude oil price to natural gas price in three cases, 1990-2030: History: Energy Information Administration, *Annual Energy Review 2007*, DOE/EIA-0384(2007) (Washington, DC, June 2008). **Projections:** AEO2009 National Energy Modeling System, runs AEO2009.D120908A, LP2009.D122308A, and HP2009.D121108A.

Figure 18. Cumulative additions to U.S. electricity generation capacity by fuel in four cases, 2008-2030: AEO2009 National Energy Modeling System, runs AEO2009.D120908A, FRZCST09.D121108A, INCCST09.D121208A, and DECCST09.D121108A.

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Figure 20. Electricity prices in four cases, 2007-2030: AEO2009 National Energy Modeling System, runs AEO2009.D120908A, FRZCST09.D121108A, INCCST09.D121208A, and DECCST09.D121108A.

Figure 21. Installed renewable generation capacity, 1981-2007: Energy Information Administration, *Annual Energy Review 2007*, DOE/EIA-0384 (2007) (Washington, DC, June 2008).

Figure 22. Installed renewable generation capacity in two cases, 2007-2030: 2007: Energy Information Administration, *Annual Energy Review 2007*, DOE/EIA-0384(2007) (Washington, DC, June 2008). **Projections:** AEO2009 National Energy Modeling System, runs AEO2009.D120908A and PTC09.D010709A.

Figure 23. Cumulative additions to U.S. generating capacity in three cases, 2008-2030: AEO2009 National Energy Modeling System, runs AEO2009.D120908A, NORSK2009.D120908A, and CAP2009.D010909A.

Figure 24. U.S. electricity generation by source in three cases, 2007 and 2030: 2007: Energy Information Administration, *Annual Energy Review 2007*, DOE/EIA-0384(2007) (Washington, DC, June 2008). **Projections:** AEO2009 National Energy Modeling System, runs AEO2009.D120908A, NORSK2009.D120908A, and CAP2009.D010909A.

Figure 25. U.S. electricity prices in three cases, 2005-2030: History: Energy Information Administration, *Annual Energy Review 2007*, DOE/EIA-0384(2007) (Washington, DC, June 2008). **Projections:** AEO2009 National Energy Modeling System, runs AEO2009.D120908A, NORSK2009.D120908A, and CAP2009.D010909A.

Figure 26. Carbon dioxide emissions from the U.S. electric power sector in three cases, 2005-2030: History: Energy Information Administration, *Annual Energy Review 2007*, DOE/EIA-0384(2007) (Washington, DC, June 2008). **Projections:** AEO2009 National Energy Modeling System, runs AEO2009.D120908A, NORSK2009.D120908A, and CAP2009.D010909A.

Figure 27. Average annual growth rates of real GDP, labor force, and productivity in three cases, 2007-2030: Appendix B, Table B4.

Figure 28. Average annual inflation, interest, and unemployment rates in three cases, 2007-2030: Appendix B, Table B4.

Figure 29. Sectoral composition of industrial output growth rates in three cases, 2007-2030: AEO2009 National Energy Modeling System, runs AEO2009.D120908A, HM2009.D120908A, and LM2009.D120908A.

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Figure 31. Energy expenditures as a share of gross domestic product, 1970-2030: History: U.S. Department of Commerce, Bureau of Economic Analysis, and Energy Information Administration, *Annual Energy Review 2007*, DOE/EIA-0384(2007) (Washington, DC, June 2008). **Projections:** AEO2009 National Energy Modeling System, run AEO2009.D120908A.

Figure 32. World oil prices in three cases, 1980-2030: History: Energy Information Administration, *Annual Energy Review 2007*, DOE/EIA-0384(2007) (Washington, DC, June 2008). **Projections:** AEO2009 National Energy Modeling System, runs AEO2009.D120908A, LP2009.D122308A, and HP2009.D121108A.

Figure 33. Unconventional resources as a share of the world liquids market in three cases, 2007 and 2030: 2007: Derived from Energy Information Administration, *International Energy Annual 2005* (June-October 2007), Table G.4, web site www.eia.doe.gov/iea. **Projections:** AEO2009 National Energy Modeling System, runs AEO2009.D120908A, LP2009.D122308A, and HP2009.D121108A.

Figure 34. World liquids production shares by region in three cases, 2007 and 2030: AEO2009 National Energy Modeling System, runs AEO2009.D120908A, LP2009.D122308A, and HP2009.D121108A.

Figure 35. Energy use per capita and per dollar of gross domestic product, 1980-2030: History: Energy Information Administration, *Annual Energy Review 2007*, DOE/EIA-0384(2007) (Washington, DC, June 2008). **Projections:** AEO2009 National Energy Modeling System, run AEO2009.D120908A.

Figure 36. Primary energy use by end-use sector, 2007-2030: History: Energy Information Administration, *Annual Energy Review 2007*, DOE/EIA-0384(2007) (Washington, DC, June 2008). **Projections:** Appendix A, Table A2.

Figure 37. Primary energy use by fuel, 1980-2030: History: Energy Information Administration, *Annual Energy Review 2007*, DOE/EIA-0384(2007) (Washington, DC, June 2008). **Projections:** AEO2009 National Energy Modeling System, run AEO2009.D120908A.

Figure 38. Residential delivered energy consumption per capita in three cases, 1990-2030: History: Energy Information Administration, "Consumption, Price, and Expenditure Estimates" (November 2008), web site www.eia.doe.gov/emeu/states/_seds.html, and *Annual Energy Review 2007*, DOE/EIA-0384(2007) (Washington, DC, June 2008). **Projections:** AEO2009 National Energy Modeling System, runs AEO2009.D120908A, BLDFRZN.D121008A, and BLDHIGH.D121008A.

Figure 39. Residential delivered energy consumption by fuel and service, 2007, 2015, and 2030: AEO2009 National Energy Modeling System, run AEO2009.D120908A.

Figure 40. Efficiency gains for selected residential appliances in three cases, 2030: Energy Information Administration, *Technology Forecast Updates—Residential and Commercial Building Technologies—Advanced Adoption Case* (Navigant Consulting, Inc., September 2007); and AEO2009 National Energy Modeling System, runs AEO2009.D120908A, BLDFRZN.D121008A, and BLDBEST.D121008A.

Figure 41. Residential market penetration by renewable technologies in two cases, 2007, 2015, and 2030: AEO2009 National Energy Modeling System, runs AEO2009.D120908A and BLDFRZN.D121008A.

Figure 42. Commercial delivered energy consumption per capita in three cases, 1980-2030: History: Energy Information Administration, "Consumption, Price, and Expenditure Estimates" (November 2008), web site www.eia.doe.gov/emeu/states/_seds.html, and *Annual Energy Review 2007*, DOE/EIA-0384(2007) (Washington, DC, June 2008). **Projections:** AEO2009 National Energy Modeling System, runs AEO2009.D120908A, BLDFRZN.D121008A, and BLDHIGH.D121008A.

Figure 43. Commercial delivered energy consumption by fuel and service, 2007, 2015, and 2030: AEO2009 National Energy Modeling System, run AEO2009.D120908A.

Figure 44. Efficiency gains for selected commercial equipment in three cases, 2030: Energy Information Administration, *Technology Forecast Updates—Residential and Commercial Building Technologies—Advanced Adoption Case* (Navigant Consulting, Inc., September 2007); and AEO2009 National Energy Modeling System, runs AEO2009.D120908A, BLDFRZN.D121008A, and BLDBEST.D121008A.

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Figure 46. Industrial delivered energy consumption by application, 2007-2030: History: Energy Information Administration, *Annual Energy Review 2007*, DOE/EIA-0384(2007) (Washington, DC, June 2008). **Projections:** AEO2009 National Energy Modeling System, run AEO2009.D120908A.

Figure 47. Industrial energy consumption by fuel, 2000, 2007, and 2030: History: Energy Information Administration, *Annual Energy Review 2007*, DOE/EIA-0384(2007) (Washington, DC, June 2008). **Projections:** AEO2009 National Energy Modeling System, run AEO2009.D120908A.

Figure 48. Cumulative growth in value of shipments for industrial subsectors in three cases, 2007-2030: AEO2009 National Energy Modeling System, runs AEO2009.D120908A, HM2009.D120908A, and LM2009.D120908A.

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Figure 52. Sales of unconventional light-duty vehicles by fuel type, 2007, 2015, and 2030: AEO2009 National Energy Modeling System, run AEO2009.D120908A.

Figure 53. Sales shares of hybrid light-duty vehicles by type in three cases, 2030: AEO2009 National Energy Modeling System, run AEO2009.D120908A.

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Figure 57. Levelized electricity costs for new power plants, 2020 and 2030: AEO2009 National Energy Modeling System, run AEO2009.D120908A.

Figure 58. Average U.S. retail electricity prices in three cases, 1970-2030: AEO2009 National Energy Modeling System, runs AEO2009.D120908A, LM2009.D120908A, and HM2009.D120908A.

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Figure 61. Grid-connected electricity generation from renewable energy sources, 1990-2030: Energy Information Administration, *Annual Energy Review 2007*, DOE/EIA-0384(2007) (Washington, DC, June 2008). **Projections:** AEO2009 National Energy Modeling System, run AEO2009.D120908A.

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Figure 67. Total U.S. natural gas production in five cases, 1990-2030: History: Energy Information Administration, *Annual Energy Review 2007*, DOE/EIA-0384(2007) (Washington, DC, June 2008). **Projections:** AEO2009 National Energy Modeling System, runs AEO2009. D120908A, HP2009.D121108A, OGHTEC09.D121408A, LP2009.D122308A, and OGLTEC09.D121408A.

Figure 68. Net U.S. imports of natural gas by source, 1990-2030: History: Energy Information Administration, *Annual Energy Review 2007*, DOE/EIA-0384(2007) (Washington, DC, June 2008). **Projections:** AEO2009 National Energy Modeling System, run AEO2009.D120908A.

Figure 69. Lower 48 wellhead prices for natural gas in two cases, 1990-2030: History: Energy Information Administration, *Natural Gas Annual 2006*, DOE/EIA-0131 (2006) (Washington, DC, June 2008). **Projections:** AEO-2009 National Energy Modeling System, runs AEO2009. D120908A and NOAK09.D121408A.

Figure 70. Domestic crude oil production by source, 1990-2030: History: Energy Information Administration, Office of Integrated Analysis and Forecasting. **Projections:** AEO2009 National Energy Modeling System, run AEO2009.D120908A.

Figure 71. Total U.S. crude oil production in five cases, 1990-2030: History: Energy Information Administration, *Annual Energy Review 2007*, DOE/EIA-0384(2007) (Washington, DC, June 2008). **Projections:** AEO2009 National Energy Modeling System, runs AEO2009. D120908A, HP2009.D121108A, OGHTEC09.D121408A, LP2009.D122308A, and OGLTEC09.D121408A.

Figure 72. Liquids production from gasification and oil shale, 2007-2030: AEO2009 National Energy Modeling System, run AEO2009.D120908A.

Figure 73. Liquid fuels consumption by sector, 1990-2030: History: Energy Information Administration, *Annual Energy Review 2007*, DOE/EIA-0384(2007) (Washington, DC, June 2008). **Projections:** AEO2009 National Energy Modeling System, run AEO2009.D120908A.

Figure 74. RFS credits earned in selected years, 2007-2030: AEO2009 National Energy Modeling System, run AEO2009.D120908A.

Figure 75. Biofuel content of U.S. motor gasoline and diesel consumption, 2007, 2015, and 2030: AEO-2009 National Energy Modeling System, run AEO2009. D120908A.

Figure 76. Motor gasoline, diesel fuel, and E85 prices, 2007-2030: History: Energy Information Administration, *Annual Energy Review 2007*, DOE/EIA-0384 (2007) (Washington, DC, June 2008). **Projections:** AEO-2009 National Energy Modeling System, run AEO2009. D120908A.

Figure 77. Net import share of U.S. liquid fuels consumption in three cases, 1990-2030: History: Energy Information Administration, *Annual Energy Review 2007*, DOE/EIA-0384(2007) (Washington, DC, June 2008). **Projections:** AEO2009 National Energy Modeling System, runs AEO2009.D120908A, LP2009.D122308A, and HP2009.D121108A.

Figure 78. Coal production by region, 1970-2030: History (short tons): 1970-1990: Energy Information Administration, *The U.S. Coal Industry, 1970-1990: Two Decades of Change*, DOE/EIA-0559 (Washington, DC, November 2002). **1991-2000:** Energy Information Administration, *Coal Industry Annual*, DOE/EIA-0584 (various years). **2001-2007:** Energy Information Administration, *Annual Coal Report 2007*, DOE/EIA-0584(2007) (Washington, DC, September 2008), and previous issues. **History (conversion to quadrillion Btu): 1970-2007: Estimation Procedure:** Energy Information Administration, Office of Integrated Analysis and Forecasting. Estimates of average heat content by region and year are based on coal quality data collected through various energy surveys (see sources) and national-level estimates of U.S. coal production by year in units of quadrillion Btu, published in EIA's *Annual Energy Review*. **Sources:** Energy Information Administration, *Annual Energy Review 2007*, DOE/EIA-0384(2007) (Washington, DC, June 2008), Table 1.2; Form EIA-3, "Quarterly Coal Consumption and Quality Report, Manufacturing Plants"; Form EIA-5, "Quarterly Coal Consumption and Quality Report, Coke Plants"; Form EIA-6A, "Coal Distribution Report"; Form EIA-7A, "Coal Production

Report"; Form EIA-423, "Monthly Cost and Quality of Fuels for Electric Plants Report"; Form EIA-906, "Power Plant Report"; Form EIA-920, "Combined Heat and Power Plant Report"; U.S. Department of Commerce, Bureau of the Census, "Monthly Report EM 545"; and Federal Energy Regulatory Commission, Form 423, "Monthly Report of Cost and Quality of Fuels for Electric Plants." **Projections:** AEO2009 National Energy Modeling System, run AEO2009.D120908A. **Note:** For 1989-2030, coal production includes waste coal.

Figure 79. U.S. coal production in four cases, 2007, 2015, and 2030: AEO2009 National Energy Modeling System, runs AEO2009.D120908A, CAP2009.D010909A, NORSK2009.D120908A, LCCST09.D121608A, and HCCST09.D121608A. **Note:** Coal production includes waste coal.

Figure 80. Average minemouth coal prices by region, 1990-2030: History (dollars per short ton): 1990-2000: Energy Information Administration, *Coal Industry Annual*, DOE/EIA-0584 (various years). **2001-2007:** Energy Information Administration, *Annual Coal Report 2007*, DOE/EIA-0584 (2007) (Washington, DC, September 2008), and previous issues. **History (conversion to dollars per million Btu): 1970-2007:** Estimation Procedure: Energy Information Administration, Office of Integrated Analysis and Forecasting. Estimates of average heat content by region and year based on coal quality data collected through various energy surveys (see sources) and national-level estimates of U.S. coal production by year in units of quadrillion Btu published in EIA's *Annual Energy Review*. **Sources:** Energy Information Administration, *Annual Energy Review 2007*, DOE/EIA-0384(2007) (Washington, DC, June 2008), Table 1.2; Form EIA-3, "Quarterly Coal Consumption and Quality Report, Manufacturing Plants"; Form EIA-5, "Quarterly Coal Consumption and Quality Report, Coke Plants"; Form EIA-6A, "Coal Distribution Report"; Form EIA-7A, "Coal Production Report"; Form EIA-423, "Monthly Cost and Quality of Fuels for Electric Plants Report"; Form EIA-906, "Power Plant Report"; and Form EIA-920, "Combined Heat and Power Plant Report"; U.S. Department of Commerce, Bureau of the Census, "Monthly Report EM 545"; and Federal Energy Regulatory Commission, Form 423, "Monthly Report of Cost and Quality of Fuels for Electric Plants." **Projections:** AEO2009 National Energy Modeling System, run AEO2009.D120908A. **Note:** Includes reported prices for both open-market and captive mines.

Figure 81. Carbon dioxide emissions by sector and fuel, 2007 and 2030: History: 1980-2006: Energy Information Admininstration, *Annual Energy Review 2007*, DOE/EIA-0384(2007) (Washington, DC, June 2008), Table 12.2. **2007:** Energy Information Administration, *Emissions of Greenhouse Gases in the United States 2007*, DOE/EIA-0573(2007) (Washington, DC, December 2008). **2030:** AEO2009 National Energy Modeling System, run AEO2009.D120908A.

Figure 82. Sulfur dioxide emissions from electricity generation, 1995-2030: History: 1995: U.S. Environmental Protection Agency, *National Air Pollutant Emissions Trends, 1990-1998*, EPA-454/R-00-002 (Washington, DC, March 2000). **2000:** U.S. Environmental Protection Agency, *Acid Rain Program Preliminary Summary Emissions Report, Fourth Quarter 2004*, web site www.epa.gov/airmarkets/emissions/prelimarp/index.html. **2007 and Projections:** AEO2009 National Energy Modeling System, run AEO2009.D120908A.

Figure 83. Nitrogen oxide emissions from electricity generation, 1995-2030: History: 1995: U.S. Environmental Protection Agency, *National Air Pollutant Emissions Trends, 1990-1998*, EPA-454/R-00-002 (Washington, DC, March 2000). **2000:** U.S. Environmental Protection Agency, *Acid Rain Program Preliminary Summary Emissions Report, Fourth Quarter 2004*, web site www.epa.gov/airmarkets/emissions/prelimarp/index.html. **2007 and Projections:** AEO2009 National Energy Modeling System, run AEO2009.D120908A.

Appendixes

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

Supply, Disposition, and Prices	Reference Case							Annual Growth 2007-2030 (percent)
	2006	2007	2010	2015	2020	2025	2030	
Production								
Crude Oil and Lease Condensate	10.80	10.73	12.19	12.40	14.06	15.63	15.96	1.7%
Natural Gas Plant Liquids	2.36	2.41	2.58	2.55	2.57	2.62	2.61	0.3%
Dry Natural Gas	18.99	19.84	20.95	20.88	22.08	23.87	24.26	0.9%
Coal[1]	23.79	23.50	24.21	24.49	24.43	25.11	26.93	0.6%
Nuclear Power	8.21	8.41	8.45	8.68	8.99	9.04	9.47	0.5%
Hydropower	2.87	2.46	2.67	2.94	2.95	2.96	2.97	0.8%
Biomass[2]	2.97	3.23	4.20	5.18	6.52	7.83	8.25	4.2%
Other Renewable Energy[3]	0.88	0.97	1.54	1.63	1.74	1.95	2.19	3.6%
Other[4]	0.42	0.94	0.85	1.08	1.07	1.07	1.15	0.9%
Total	**71.29**	**72.49**	**77.64**	**79.83**	**84.41**	**90.09**	**93.79**	**1.1%**
Imports								
Crude Oil	22.08	21.90	17.76	17.82	16.09	14.76	15.39	-1.5%
Liquid Fuels and Other Petroleum[5]	7.22	6.97	5.59	5.69	5.67	5.79	6.33	-0.4%
Natural Gas	4.29	4.72	3.27	3.60	3.37	3.12	2.58	-2.6%
Other Imports[6]	0.98	0.99	0.89	0.96	1.19	1.11	1.35	1.3%
Total	**34.57**	**34.59**	**27.51**	**28.07**	**26.31**	**24.79**	**25.65**	**-1.3%**
Exports								
Petroleum[7]	2.59	2.84	2.56	2.68	2.90	3.06	3.17	0.5%
Natural Gas	0.73	0.83	0.70	1.16	1.44	1.71	1.87	3.6%
Coal	1.26	1.51	2.05	1.65	1.33	1.34	1.08	-1.4%
Total	**4.58**	**5.17**	**5.31**	**5.49**	**5.66**	**6.11**	**6.12**	**0.7%**
Discrepancy[8]	**1.26**	**0.01**	**-0.02**	**-0.46**	**-0.39**	**-0.29**	**-0.25**	**- -**
Consumption								
Liquid Fuels and Other Petroleum[9]	40.63	40.75	37.89	38.86	38.93	39.84	41.60	0.1%
Natural Gas	22.26	23.70	23.20	23.40	24.09	25.36	25.04	0.2%
Coal[10]	22.46	22.74	22.91	23.59	23.98	24.45	26.56	0.7%
Nuclear Power	8.21	8.41	8.45	8.68	8.99	9.04	9.47	0.5%
Hydropower	2.87	2.46	2.67	2.94	2.95	2.96	2.97	0.8%
Biomass[11]	2.52	2.62	2.99	3.59	4.58	5.27	5.51	3.3%
Other Renewable Energy[3]	0.88	0.97	1.54	1.63	1.74	1.95	2.19	3.6%
Other[12]	0.19	0.23	0.21	0.19	0.19	0.18	0.22	-0.2%
Total	**100.02**	**101.89**	**99.85**	**102.87**	**105.44**	**109.05**	**113.56**	**0.5%**
Prices (2007 dollars per unit)								
Petroleum (dollars per barrel)								
Imported Low Sulfur Light Crude Oil Price[13]	67.82	72.33	80.16	110.49	115.45	121.94	130.43	2.6%
Imported Crude Oil Price[13]	60.70	63.83	77.56	108.52	112.05	115.33	124.60	3.0%
Natural Gas (dollars per million Btu)								
Price at Henry Hub	6.91	6.96	6.66	6.90	7.43	8.08	9.25	1.2%
Wellhead Price[14]	6.48	6.22	5.88	6.10	6.56	7.13	8.17	1.2%
Natural Gas (dollars per thousand cubic feet)								
Wellhead Price[14]	6.66	6.39	6.05	6.27	6.75	7.33	8.40	1.2%
Coal (dollars per ton)								
Minemouth Price[15]	25.29	25.82	29.45	28.71	27.90	28.45	29.10	0.5%
Coal (dollars per million Btu)								
Minemouth Price[15]	1.25	1.27	1.44	1.42	1.39	1.42	1.46	0.6%
Average Delivered Price[16]	1.83	1.86	1.99	2.02	1.99	2.02	2.08	0.5%
Average Electricity Price (cents per kilowatthour)	9.1	9.1	9.0	9.1	9.4	9.8	10.4	0.6%

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

Supply, Disposition, and Prices	Reference Case							Annual Growth 2007-2030 (percent)
	2006	2007	2010	2015	2020	2025	2030	
Prices (nominal dollars per unit)								
Petroleum (dollars per barrel)								
Imported Low Sulfur Light Crude Oil Price[13]	66.04	72.33	84.42	127.84	149.14	168.24	189.10	4.3%
Imported Crude Oil Price[13]	59.10	63.83	81.69	125.57	144.74	159.11	180.66	4.6%
Natural Gas (dollars per million Btu)								
Price at Henry Hub	6.73	6.96	7.01	7.99	9.60	11.14	13.42	2.9%
Wellhead Price[14]	6.31	6.22	6.19	7.06	8.48	9.84	11.85	2.8%
Natural Gas (dollars per thousand cubic feet)								
Wellhead Price[14]	6.49	6.39	6.37	7.26	8.72	10.12	12.18	2.8%
Coal (dollars per ton)								
Minemouth Price[15]	24.63	25.82	31.02	33.22	36.04	39.26	42.20	2.2%
Coal (dollars per million Btu)								
Minemouth Price[15]	1.21	1.27	1.52	1.65	1.80	1.96	2.11	2.2%
Average Delivered Price[16]	1.78	1.86	2.10	2.34	2.57	2.79	3.01	2.1%
Average Electricity Price (cents per kilowatthour)	8.9	9.1	9.5	10.5	12.2	13.6	15.1	2.2%

[1]Includes waste coal.
[2]Includes grid-connected electricity from wood and waste; biomass, such as corn, used for liquid fuels production; and non-electric energy demand from wood. Refer to Table A17 for details.
[3]Includes grid-connected electricity from landfill gas; biogenic municipal waste; wind; photovoltaic and solar thermal sources; and non-electric energy from renewable sources, such as active and passive solar systems. Excludes electricity imports using renewable sources and nonmarketed renewable energy. See Table A17 for selected nonmarketed residential and commercial renewable energy.
[4]Includes non-biogenic municipal waste, liquid hydrogen, methanol, and some domestic inputs to refineries.
[5]Includes imports of finished petroleum products, unfinished oils, alcohols, ethers, blending components, and renewable fuels such as ethanol.
[6]Includes coal, coal coke (net), and electricity (net).
[7]Includes crude oil and petroleum products.
[8]Balancing item. Includes unaccounted for supply, losses, gains, and net storage withdrawals.
[9]Includes petroleum-derived fuels and non-petroleum derived fuels, such as ethanol and biodiesel, and coal-based synthetic liquids. Petroleum coke, which is a solid, is included. Also included are natural gas plant liquids, crude oil consumed as a fuel, and liquid hydrogen. Refer to Table A17 for detailed renewable liquid fuels consumption.
[10]Excludes coal converted to coal-based synthetic liquids.
[11]Includes grid-connected electricity from wood and wood waste, non-electric energy from wood, and biofuels heat and coproducts used in the production of liquid fuels, but excludes the energy content of the liquid fuels.
[12]Includes non-biogenic municipal waste and net electricity imports.
[13]Weighted average price delivered to U.S. refiners.
[14]Represents lower 48 onshore and offshore supplies.
[15]Includes reported prices for both open market and captive mines.
[16]Prices weighted by consumption; weighted average excludes residential and commercial prices, and export free-alongside-ship (f.a.s.) prices.
Btu = British thermal unit.
- - = Not applicable.
Note: Totals may not equal sum of components due to independent rounding. Data for 2006 and 2007 are model results and may differ slightly from official EIA data reports.
Sources: 2006 natural gas supply values: Energy Information Administration (EIA), *Natural Gas Annual 2006*, DOE/EIA-0131(2006) (Washington, DC, October 2007). 2007 natural gas supply values and natural gas wellhead price: EIA, *Natural Gas Monthly*, DOE/EIA-0130(2008/08) (Washington, DC, August 2008). 2006 natural gas wellhead price: Minerals Management Service and EIA, *Natural Gas Annual 2006*, DOE/EIA-0131(2006) (Washington, DC, October 2007). 2006 and 2007 coal minemouth and delivered coal prices: EIA, *Annual Coal Report 2007*, DOE/EIA-0584(2007) (Washington, DC, September 2008). 2007 petroleum supply values and 2006 crude oil and lease condensate production: EIA, *Petroleum Supply Annual 2007,* DOE/EIA-0340(2007)/1 (Washington, DC, July 2008). Other 2006 petroleum supply values: EIA, *Petroleum Supply Annual 2006,* DOE/EIA-0340(2006)/1 (Washington, DC, September 2007). 2006 and 2007 low sulfur light crude oil price: EIA, Form EIA-856, "Monthly Foreign Crude Oil Acquisition Report." Other 2006 and 2007 coal values: *Quarterly Coal Report, October-December 2007*, DOE/EIA-0121(2007/4Q) (Washington, DC, March 2008). Other 2006 and 2007 values: EIA, *Annual Energy Review 2007*, DOE/EIA-0384(2007) (Washington, DC, June 2008).
Projections: EIA, AEO2009 National Energy Modeling System run AEO2009.D120908A.

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

Sector and Source	Reference Case							Annual Growth 2007-2030 (percent)
	2006	2007	2010	2015	2020	2025	2030	
Energy Consumption								
Residential								
Liquefied Petroleum Gases	0.49	0.50	0.49	0.48	0.49	0.50	0.52	0.2%
Kerosene	0.07	0.08	0.08	0.07	0.07	0.07	0.07	-0.5%
Distillate Fuel Oil	0.71	0.78	0.72	0.64	0.60	0.55	0.51	-1.8%
Liquid Fuels and Other Petroleum Subtotal	1.27	1.35	1.29	1.19	1.16	1.13	1.10	-0.9%
Natural Gas	4.49	4.86	4.92	5.01	5.10	5.13	5.07	0.2%
Coal	0.01	0.01	0.01	0.01	0.01	0.01	0.01	-0.8%
Renewable Energy[1]	0.39	0.43	0.43	0.46	0.48	0.49	0.50	0.7%
Electricity	4.61	4.75	4.80	4.85	5.12	5.39	5.69	0.8%
Delivered Energy	**10.77**	**11.40**	**11.44**	**11.52**	**11.86**	**12.14**	**12.36**	**0.4%**
Electricity Related Losses	10.00	10.36	10.44	10.35	10.81	11.17	11.69	0.5%
Total	**20.77**	**21.76**	**21.88**	**21.87**	**22.67**	**23.31**	**24.05**	**0.4%**
Commercial								
Liquefied Petroleum Gases	0.09	0.09	0.09	0.10	0.10	0.10	0.10	0.3%
Motor Gasoline[2]	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.4%
Kerosene	0.02	0.01	0.01	0.01	0.01	0.01	0.01	1.4%
Distillate Fuel Oil	0.40	0.41	0.36	0.34	0.34	0.34	0.34	-0.8%
Residual Fuel Oil	0.08	0.08	0.07	0.08	0.08	0.08	0.08	0.3%
Liquid Fuels and Other Petroleum Subtotal	0.63	0.63	0.58	0.58	0.58	0.59	0.59	-0.3%
Natural Gas	2.92	3.10	3.14	3.25	3.34	3.45	3.54	0.6%
Coal	0.07	0.07	0.06	0.06	0.06	0.06	0.06	-0.0%
Renewable Energy[3]	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.0%
Electricity	4.43	4.58	4.75	5.14	5.57	5.95	6.31	1.4%
Delivered Energy	**8.17**	**8.50**	**8.66**	**9.15**	**9.69**	**10.17**	**10.62**	**1.0%**
Electricity Related Losses	9.62	9.99	10.35	10.95	11.77	12.32	12.96	1.1%
Total	**17.79**	**18.49**	**19.01**	**20.10**	**21.46**	**22.49**	**23.59**	**1.1%**
Industrial[4]								
Liquefied Petroleum Gases	2.33	2.35	2.02	1.97	1.79	1.72	1.66	-1.5%
Motor Gasoline[2]	0.36	0.36	0.34	0.35	0.34	0.34	0.36	-0.1%
Distillate Fuel Oil	1.26	1.28	1.17	1.21	1.18	1.19	1.23	-0.1%
Residual Fuel Oil	0.24	0.25	0.15	0.16	0.16	0.16	0.16	-1.9%
Petrochemical Feedstocks	1.42	1.30	1.01	1.20	1.13	1.10	1.05	-0.9%
Other Petroleum[5]	4.51	4.42	3.74	3.82	3.72	3.72	3.84	-0.6%
Liquid Fuels and Other Petroleum Subtotal	10.13	9.96	8.42	8.71	8.32	8.22	8.30	-0.8%
Natural Gas	6.68	6.82	6.77	6.99	6.84	6.95	7.04	0.1%
Natural-Gas-to-Liquids Heat and Power	0.00	0.00	0.00	0.00	0.00	0.00	0.00	- -
Lease and Plant Fuel[6]	1.16	1.20	1.27	1.25	1.33	1.44	1.47	0.9%
Natural Gas Subtotal	7.83	8.02	8.05	8.24	8.17	8.39	8.51	0.3%
Metallurgical Coal	0.60	0.60	0.55	0.53	0.49	0.48	0.48	-1.0%
Other Industrial Coal	1.25	1.21	1.24	1.16	1.15	1.16	1.16	-0.2%
Coal-to-Liquids Heat and Power	0.00	0.00	0.00	0.13	0.24	0.40	0.58	- -
Net Coal Coke Imports	0.06	0.03	0.01	0.01	0.01	0.01	0.01	-3.6%
Coal Subtotal	1.92	1.83	1.80	1.84	1.89	2.05	2.23	0.9%
Biofuels Heat and Coproducts	0.30	0.40	0.75	0.95	1.23	1.62	1.66	6.4%
Renewable Energy[7]	1.70	1.64	1.48	1.56	1.64	1.78	1.96	0.8%
Electricity	3.45	3.43	3.34	3.50	3.48	3.54	3.67	0.3%
Delivered Energy	**25.33**	**25.29**	**23.83**	**24.79**	**24.73**	**25.60**	**26.33**	**0.2%**
Electricity Related Losses	7.48	7.49	7.27	7.45	7.36	7.32	7.55	0.0%
Total	**32.81**	**32.77**	**31.10**	**32.24**	**32.09**	**32.93**	**33.87**	**0.1%**

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

Sector and Source	Reference Case							Annual Growth 2007-2030 (percent)
	2006	2007	2010	2015	2020	2025	2030	
Transportation								
Liquefied Petroleum Gases	0.02	0.02	0.01	0.01	0.01	0.01	0.02	-0.2%
E85[8]	0.00	0.00	0.00	0.35	0.85	1.70	2.18	37.1%
Motor Gasoline[2]	17.22	17.29	16.93	16.25	15.56	14.73	14.49	-0.8%
Jet Fuel[9]	3.22	3.23	3.00	3.15	3.42	3.74	4.12	1.1%
Distillate Fuel Oil[10]	6.41	6.48	6.13	6.97	7.36	8.02	9.09	1.5%
Residual Fuel Oil	0.91	0.95	0.86	0.96	0.98	0.99	1.00	0.2%
Liquid Hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	44.5%
Other Petroleum[11]	0.18	0.17	0.17	0.18	0.18	0.18	0.18	0.3%
Liquid Fuels and Other Petroleum Subtotal	27.96	28.14	27.11	27.87	28.36	29.38	31.09	0.4%
Pipeline Fuel Natural Gas	0.60	0.64	0.64	0.65	0.69	0.73	0.72	0.5%
Compressed Natural Gas	0.02	0.02	0.03	0.05	0.07	0.08	0.09	5.8%
Electricity	0.02	0.02	0.02	0.03	0.03	0.04	0.05	3.7%
Delivered Energy	**28.60**	**28.82**	**27.81**	**28.60**	**29.15**	**30.23**	**31.94**	**0.4%**
Electricity Related Losses	0.05	0.05	0.05	0.06	0.07	0.09	0.10	3.4%
Total	**28.65**	**28.87**	**27.86**	**28.66**	**29.22**	**30.32**	**32.05**	**0.5%**
Delivered Energy Consumption for All Sectors								
Liquefied Petroleum Gases	2.93	2.95	2.61	2.55	2.39	2.34	2.29	-1.1%
E85[8]	0.00	0.00	0.00	0.35	0.85	1.70	2.18	37.1%
Motor Gasoline[2]	17.62	17.70	17.33	16.64	15.95	15.12	14.90	-0.7%
Jet Fuel[9]	3.22	3.23	3.00	3.15	3.42	3.74	4.12	1.1%
Kerosene	0.12	0.11	0.10	0.10	0.10	0.10	0.10	-0.2%
Distillate Fuel Oil	8.79	8.94	8.38	9.17	9.49	10.11	11.17	1.0%
Residual Fuel Oil	1.22	1.28	1.07	1.21	1.22	1.23	1.25	-0.1%
Petrochemical Feedstocks	1.42	1.30	1.01	1.20	1.13	1.10	1.05	-0.9%
Liquid Hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	44.5%
Other Petroleum[12]	4.66	4.57	3.89	3.98	3.89	3.88	4.01	-0.6%
Liquid Fuels and Other Petroleum Subtotal	39.98	40.08	37.40	38.36	38.42	39.32	41.07	0.1%
Natural Gas	14.11	14.79	14.86	15.30	15.34	15.60	15.73	0.3%
Natural-Gas-to-Liquids Heat and Power	0.00	0.00	0.00	0.00	0.00	0.00	0.00	- -
Lease and Plant Fuel[6]	1.16	1.20	1.27	1.25	1.33	1.44	1.47	0.9%
Pipeline Natural Gas	0.60	0.64	0.64	0.65	0.69	0.73	0.72	0.5%
Natural Gas Subtotal	15.86	16.64	16.78	17.20	17.36	17.77	17.92	0.3%
Metallurgical Coal	0.60	0.60	0.55	0.53	0.49	0.48	0.48	-1.0%
Other Coal	1.33	1.28	1.31	1.24	1.22	1.23	1.23	-0.2%
Coal-to-Liquids Heat and Power	0.00	0.00	0.00	0.13	0.24	0.40	0.58	- -
Net Coal Coke Imports	0.06	0.03	0.01	0.01	0.01	0.01	0.01	-3.6%
Coal Subtotal	1.99	1.91	1.87	1.91	1.97	2.12	2.30	0.8%
Biofuels Heat and Coproducts	0.30	0.40	0.75	0.95	1.23	1.62	1.66	6.4%
Renewable Energy[13]	2.21	2.19	2.03	2.14	2.24	2.39	2.58	0.7%
Electricity	12.52	12.79	12.91	13.51	14.20	14.92	15.73	0.9%
Delivered Energy	**72.87**	**74.01**	**71.74**	**74.07**	**75.42**	**78.15**	**81.26**	**0.4%**
Electricity Related Losses	27.15	27.88	28.11	28.80	30.02	30.90	32.30	0.6%
Total	**100.02**	**101.89**	**99.85**	**102.87**	**105.44**	**109.05**	**113.56**	**0.5%**
Electric Power[14]								
Distillate Fuel Oil	0.10	0.11	0.11	0.12	0.12	0.12	0.13	0.8%
Residual Fuel Oil	0.54	0.56	0.38	0.38	0.39	0.39	0.40	-1.5%
Liquid Fuels and Other Petroleum Subtotal	0.65	0.67	0.49	0.50	0.51	0.52	0.53	-1.0%
Natural Gas	6.39	7.06	6.42	6.21	6.73	7.59	7.12	0.0%
Steam Coal	20.46	20.84	21.03	21.68	22.01	22.33	24.25	0.7%
Nuclear Power	8.21	8.41	8.45	8.68	8.99	9.04	9.47	0.5%
Renewable Energy[15]	3.76	3.45	4.42	5.07	5.79	6.17	6.43	2.7%
Electricity Imports	0.06	0.11	0.08	0.06	0.06	0.05	0.10	-0.5%
Total[16]	**39.67**	**40.67**	**41.02**	**42.32**	**44.22**	**45.82**	**48.03**	**0.7%**

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

Sector and Source	Reference Case							Annual Growth 2007-2030 (percent)
	2006	2007	2010	2015	2020	2025	2030	
Total Energy Consumption								
Liquefied Petroleum Gases	2.93	2.95	2.61	2.55	2.39	2.34	2.29	-1.1%
E85[8]	0.00	0.00	0.00	0.35	0.85	1.70	2.18	37.1%
Motor Gasoline[2]	17.62	17.70	17.33	16.64	15.95	15.12	14.90	-0.7%
Jet Fuel[9]	3.22	3.23	3.00	3.15	3.42	3.74	4.12	1.1%
Kerosene	0.12	0.11	0.10	0.10	0.10	0.10	0.10	-0.2%
Distillate Fuel Oil	8.89	9.05	8.49	9.29	9.61	10.23	11.31	1.0%
Residual Fuel Oil	1.77	1.84	1.45	1.59	1.60	1.62	1.64	-0.5%
Petrochemical Feedstocks	1.42	1.30	1.01	1.20	1.13	1.10	1.05	-0.9%
Liquid Hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	44.5%
Other Petroleum[12]	4.66	4.57	3.89	3.98	3.89	3.88	4.01	-0.6%
Liquid Fuels and Other Petroleum Subtotal	40.63	40.75	37.89	38.86	38.93	39.84	41.60	0.1%
Natural Gas	20.50	21.86	21.29	21.50	22.07	23.19	22.86	0.2%
Natural-Gas-to-Liquids Heat and Power	0.00	0.00	0.00	0.00	0.00	0.00	0.00	- -
Lease and Plant Fuel[6]	1.16	1.20	1.27	1.25	1.33	1.44	1.47	0.9%
Pipeline Natural Gas	0.60	0.64	0.64	0.65	0.69	0.73	0.72	0.5%
Natural Gas Subtotal	22.26	23.70	23.20	23.40	24.09	25.36	25.04	0.2%
Metallurgical Coal	0.60	0.60	0.55	0.53	0.49	0.48	0.48	-1.0%
Other Coal	21.79	22.12	22.34	22.92	23.24	23.55	25.49	0.6%
Coal-to-Liquids Heat and Power	0.00	0.00	0.00	0.13	0.24	0.40	0.58	- -
Net Coal Coke Imports	0.06	0.03	0.01	0.01	0.01	0.01	0.01	-3.6%
Coal Subtotal	22.46	22.74	22.91	23.59	23.98	24.45	26.56	0.7%
Nuclear Power	8.21	8.41	8.45	8.68	8.99	9.04	9.47	0.5%
Biofuels Heat and Coproducts	0.30	0.40	0.75	0.95	1.23	1.62	1.66	6.4%
Renewable Energy[17]	5.97	5.65	6.45	7.21	8.03	8.57	9.01	2.1%
Electricity Imports	0.06	0.11	0.08	0.06	0.06	0.05	0.10	-0.5%
Total	**100.02**	**101.89**	**99.85**	**102.87**	**105.44**	**109.05**	**113.56**	**0.5%**
Energy Use and Related Statistics								
Delivered Energy Use	72.87	74.01	71.74	74.07	75.42	78.15	81.26	0.4%
Total Energy Use	100.02	101.89	99.85	102.87	105.44	109.05	113.56	0.5%
Ethanol Consumed in Motor Gasoline and E85	0.47	0.56	1.08	1.39	1.66	2.16	2.47	6.6%
Population (millions)	299.57	302.41	311.37	326.70	342.61	358.87	375.12	0.9%
Gross Domestic Product (billion 2000 dollars)	11295	11524	11779	13745	15524	17591	20114	2.5%
Carbon Dioxide Emissions (million metric tons)	5906.8	5990.8	5801.4	5903.5	5982.3	6125.3	6414.4	0.3%

[1]Includes wood used for residential heating. See Table A4 and/or Table A17 for estimates of nonmarketed renewable energy consumption for geothermal heat pumps, solar thermal hot water heating, and solar photovoltaic electricity generation.
[2]Includes ethanol (blends of 10 percent or less) and ethers blended into gasoline.
[3]Excludes ethanol. Includes commercial sector consumption of wood and wood waste, landfill gas, municipal waste, and other biomass for combined heat and power. See Table A5 and/or Table A17 for estimates of nonmarketed renewable energy consumption for solar thermal hot water heating and solar photovoltaic electricity generation.
[4]Includes energy for combined heat and power plants, except those whose primary business is to sell electricity, or electricity and heat, to the public.
[5]Includes petroleum coke, asphalt, road oil, lubricants, still gas, and miscellaneous petroleum products.
[6]Represents natural gas used in well, field, and lease operations, and in natural gas processing plant machinery.
[7]Includes consumption of energy produced from hydroelectric, wood and wood waste, municipal waste, and other biomass sources. Excludes ethanol blends (10 percent or less) in motor gasoline.
[8]E85 refers to a blend of 85 percent ethanol (renewable) and 15 percent motor gasoline (nonrenewable). To address cold starting issues, the percentage of ethanol varies seasonally. The annual average ethanol content of 74 percent is used for this forecast.
[9]Includes only kerosene type.
[10]Diesel fuel for on- and off- road use.
[11]Includes aviation gasoline and lubricants.
[12]Includes unfinished oils, natural gasoline, motor gasoline blending components, aviation gasoline, lubricants, still gas, asphalt, road oil, petroleum coke, and miscellaneous petroleum products.
[13]Includes electricity generated for sale to the grid and for own use from renewable sources, and non-electric energy from renewable sources. Excludes ethanol and nonmarketed renewable energy consumption for geothermal heat pumps, buildings photovoltaic systems, and solar thermal hot water heaters.
[14]Includes consumption of energy by electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public. Includes small power producers and exempt wholesale generators.
[15]Includes conventional hydroelectric, geothermal, wood and wood waste, biogenic municipal waste, other biomass, wind, photovoltaic, and solar thermal sources. Excludes net electricity imports.
[16]Includes non-biogenic municipal waste not included above.
[17]Includes conventional hydroelectric, geothermal, wood and wood waste, biogenic municipal waste, other biomass, wind, photovoltaic, and solar thermal sources. Excludes ethanol, net electricity imports, and nonmarketed renewable energy consumption for geothermal heat pumps, buildings photovoltaic systems, and solar thermal hot water heaters.
Btu = British thermal unit.
- - = Not applicable.
Note: Totals may not equal sum of components due to independent rounding. Data for 2006 and 2007 are model results and may differ slightly from official EIA data reports.
Sources: 2006 and 2007 consumption based on: Energy Information Administration (EIA), *Annual Energy Review 2007*, DOE/EIA-0384(2007) (Washington, DC, June 2008). 2006 and 2007 population and gross domestic product: IHS Global Insight Industry and Employment models, November 2008. 2006 and 2007 carbon dioxide emissions: EIA, *Emissions of Greenhouse Gases in the United States 2007,* DOE/EIA-0573(2007) (Washington, DC, December 2008). **Projections:** EIA, AEO2009 National Energy Modeling System run AEO2009.D120908A.

Table A3. Energy Prices by Sector and Source
(2007 Dollars per Million Btu, Unless Otherwise Noted)

Sector and Source	Reference Case							Annual Growth 2007-2030 (percent)
	2006	2007	2010	2015	2020	2025	2030	
Residential								
Liquefied Petroleum Gases	23.88	24.98	25.86	32.23	32.88	33.43	35.11	1.5%
Distillate Fuel Oil	18.46	19.66	18.69	23.59	24.10	24.84	26.67	1.3%
Natural Gas	13.70	12.69	12.09	11.98	12.50	13.07	14.31	0.5%
Electricity	31.21	31.19	30.89	31.77	32.72	34.05	35.84	0.6%
Commercial								
Liquefied Petroleum Gases	21.20	23.04	22.69	29.00	29.60	30.12	31.77	1.4%
Distillate Fuel Oil	15.02	16.05	16.15	21.64	22.11	23.06	24.69	1.9%
Residual Fuel Oil	8.88	10.21	10.97	16.12	16.68	17.07	17.98	2.5%
Natural Gas	11.90	10.99	10.55	10.57	11.13	11.74	12.96	0.7%
Electricity	28.38	28.07	27.29	27.13	28.15	29.23	31.01	0.4%
Industrial[1]								
Liquefied Petroleum Gases	21.04	23.38	21.84	28.19	28.78	29.35	30.99	1.2%
Distillate Fuel Oil	15.74	16.82	16.01	22.10	22.56	23.68	25.19	1.8%
Residual Fuel Oil	9.21	10.49	15.38	20.43	20.94	21.43	22.73	3.4%
Natural Gas[2]	7.96	7.52	6.91	7.01	7.48	7.99	9.07	0.8%
Metallurgical Coal	3.64	3.61	4.37	4.40	4.40	4.55	4.41	0.9%
Other Industrial Coal	2.40	2.43	2.54	2.57	2.53	2.57	2.67	0.4%
Coal to Liquids	- -	- -	- -	1.21	1.23	1.31	1.36	- -
Electricity	18.41	18.63	18.72	18.33	19.06	20.09	21.59	0.6%
Transportation								
Liquefied Petroleum Gases[3]	22.30	25.01	25.67	32.03	32.62	33.13	34.77	1.4%
E85[4]	25.51	26.67	25.47	25.51	29.30	29.75	30.10	0.5%
Motor Gasoline[5]	21.78	22.98	23.47	28.74	29.75	30.67	32.10	1.5%
Jet Fuel[6]	15.24	16.10	16.03	21.48	22.15	22.98	24.63	1.9%
Diesel Fuel (distillate fuel oil)[7]	20.27	20.92	20.05	25.74	26.04	27.16	28.59	1.4%
Residual Fuel Oil	8.21	9.35	12.10	17.08	17.46	18.13	19.65	3.3%
Natural Gas[8]	16.04	15.46	14.90	14.72	14.90	15.28	16.24	0.2%
Electricity	30.39	30.64	30.34	30.17	29.48	31.63	34.15	0.5%
Electric Power[9]								
Distillate Fuel Oil	13.77	14.77	15.09	19.90	20.45	21.28	23.11	2.0%
Residual Fuel Oil	8.38	8.38	13.21	18.19	18.55	19.26	20.67	4.0%
Natural Gas	7.05	7.02	6.59	6.72	7.15	7.73	8.70	0.9%
Steam Coal	1.74	1.78	1.89	1.94	1.92	1.96	2.04	0.6%
Average Price to All Users[10]								
Liquefied Petroleum Gases	15.66	18.53	20.96	26.83	27.56	28.13	29.77	2.1%
E85[4]	25.51	26.67	25.47	25.51	29.30	29.75	30.10	0.5%
Motor Gasoline[5]	21.65	22.82	23.47	28.74	29.75	30.67	32.10	1.5%
Jet Fuel	15.24	16.10	16.03	21.48	22.15	22.98	24.63	1.9%
Distillate Fuel Oil	19.17	19.94	18.98	24.89	25.28	26.42	27.94	1.5%
Residual Fuel Oil	8.42	9.25	12.66	17.64	18.03	18.67	20.12	3.4%
Natural Gas	9.50	9.01	8.56	8.64	9.11	9.61	10.75	0.8%
Metallurgical Coal	3.64	3.61	4.37	4.40	4.40	4.55	4.41	0.9%
Other Coal	1.78	1.82	1.93	1.98	1.95	1.99	2.07	0.6%
Coal to Liquids	- -	- -	- -	1.21	1.23	1.31	1.36	- -
Electricity	26.68	26.70	26.42	26.53	27.57	28.81	30.56	0.6%
Non-Renewable Energy Expenditures by Sector (billion 2007 dollars)								
Residential	231.09	238.38	235.27	246.49	263.30	282.96	310.03	1.1%
Commercial	170.28	173.09	172.88	186.98	207.76	228.67	256.75	1.7%
Industrial	216.13	226.84	204.25	244.30	242.68	253.34	276.26	0.9%
Transportation	564.63	596.75	580.97	735.45	752.82	779.67	853.25	1.6%
Total Non-Renewable Expenditures	1182.13	1235.06	1193.36	1413.22	1466.55	1544.64	1696.29	1.4%
Transportation Renewable Expenditures	0.03	0.04	0.07	8.97	24.83	50.69	65.71	37.9%
Total Expenditures	**1182.16**	**1235.10**	**1193.43**	**1422.19**	**1491.38**	**1595.33**	**1762.00**	**1.6%**

Table A3. Energy Prices by Sector and Source (Continued)
(Nominal Dollars per Million Btu, Unless Otherwise Noted)

Sector and Source	Reference Case							Annual Growth 2007-2030 (percent)
	2006	2007	2010	2015	2020	2025	2030	
Residential								
Liquefied Petroleum Gases	23.26	24.98	27.24	37.30	42.47	46.13	50.90	3.1%
Distillate Fuel Oil	17.98	19.66	19.68	27.29	31.14	34.28	38.67	3.0%
Natural Gas	13.34	12.69	12.74	13.86	16.14	18.03	20.75	2.2%
Electricity	30.39	31.19	32.53	36.77	42.26	46.98	51.96	2.2%
Commercial								
Liquefied Petroleum Gases	20.64	23.04	23.89	33.55	38.24	41.56	46.06	3.1%
Distillate Fuel Oil	14.63	16.05	17.01	25.03	28.56	31.82	35.80	3.5%
Residual Fuel Oil	8.65	10.21	11.55	18.65	21.55	23.55	26.07	4.2%
Natural Gas	11.58	10.99	11.11	12.22	14.37	16.20	18.78	2.4%
Electricity	27.63	28.07	28.74	31.39	36.37	40.33	44.96	2.1%
Industrial[1]								
Liquefied Petroleum Gases	20.49	23.38	23.00	32.62	37.17	40.49	44.93	2.9%
Distillate Fuel Oil	15.32	16.82	16.86	25.57	29.14	32.67	36.52	3.4%
Residual Fuel Oil	8.97	10.49	16.20	23.64	27.05	29.57	32.95	5.1%
Natural Gas[2]	7.75	7.52	7.27	8.11	9.66	11.03	13.16	2.5%
Metallurgical Coal	3.54	3.61	4.60	5.09	5.69	6.28	6.40	2.5%
Other Industrial Coal	2.34	2.43	2.67	2.98	3.27	3.55	3.88	2.0%
Coal to Liquids	- -	- -	- -	1.40	1.59	1.81	1.98	- -
Electricity	17.93	18.63	19.72	21.20	24.63	27.71	31.30	2.3%
Transportation								
Liquefied Petroleum Gases[3]	21.71	25.01	27.04	37.06	42.13	45.70	50.41	3.1%
E85[4]	24.84	26.67	26.83	29.51	37.85	41.04	43.63	2.2%
Motor Gasoline[5]	21.21	22.98	24.72	33.26	38.43	42.32	46.54	3.1%
Jet Fuel[6]	14.84	16.10	16.89	24.86	28.62	31.70	35.70	3.5%
Diesel Fuel (distillate fuel oil)[7]	19.74	20.92	21.12	29.78	33.63	37.48	41.44	3.0%
Residual Fuel Oil	7.99	9.35	12.74	19.76	22.56	25.02	28.49	5.0%
Natural Gas[8]	15.62	15.46	15.69	17.03	19.24	21.08	23.55	1.8%
Electricity	29.59	30.64	31.95	34.91	38.09	43.63	49.51	2.1%
Electric Power[9]								
Distillate Fuel Oil	13.41	14.77	15.89	23.03	26.42	29.36	33.51	3.6%
Residual Fuel Oil	8.16	8.38	13.91	21.05	23.97	26.57	29.97	5.7%
Natural Gas	6.87	7.02	6.94	7.77	9.24	10.67	12.61	2.6%
Steam Coal	1.69	1.78	1.99	2.25	2.48	2.70	2.95	2.2%

Table A3. Energy Prices by Sector and Source (Continued)
(Nominal Dollars per Million Btu, Unless Otherwise Noted)

Sector and Source	Reference Case							Annual Growth 2007-2030 (percent)
	2006	2007	2010	2015	2020	2025	2030	
Average Price to All Users[10]								
Liquefied Petroleum Gases	15.25	18.53	22.07	31.04	35.61	38.82	43.16	3.7%
E85[4]	24.84	26.67	26.83	29.51	37.85	41.04	43.63	2.2%
Motor Gasoline[5]	21.08	22.82	24.71	33.25	38.43	42.31	46.54	3.1%
Jet Fuel	14.84	16.10	16.89	24.86	28.62	31.70	35.70	3.5%
Distillate Fuel Oil	18.67	19.94	19.99	28.80	32.65	36.45	40.51	3.1%
Residual Fuel Oil	8.20	9.25	13.34	20.41	23.29	25.76	29.16	5.1%
Natural Gas	9.25	9.01	9.01	10.00	11.77	13.26	15.58	2.4%
Metallurgical Coal	3.54	3.61	4.60	5.09	5.69	6.28	6.40	2.5%
Other Coal	1.73	1.82	2.04	2.29	2.52	2.75	3.00	2.2%
Coal to Liquids	- -	- -	- -	1.40	1.59	1.81	1.98	- -
Electricity	25.98	26.70	27.82	30.69	35.62	39.75	44.31	2.2%
Non-Renewable Energy Expenditures by Sector (billion nominal dollars)								
Residential	225.03	238.38	247.78	285.21	340.12	390.39	449.49	2.8%
Commercial	165.82	173.09	182.07	216.35	268.38	315.48	372.25	3.4%
Industrial	210.46	226.84	215.12	282.68	313.49	349.53	400.54	2.5%
Transportation	549.82	596.75	611.87	850.99	972.48	1075.67	1237.08	3.2%
Total Non-Renewable Expenditures	1151.12	1235.06	1256.84	1635.24	1894.47	2131.06	2459.36	3.0%
Transportation Renewable Expenditures	0.03	0.04	0.07	10.38	32.08	69.93	95.27	40.1%
Total Expenditures	**1151.15**	**1235.10**	**1256.91**	**1645.62**	**1926.55**	**2201.00**	**2554.63**	**3.2%**

[1]Includes energy for combined heat and power plants, except those whose primary business is to sell electricity, or electricity and heat, to the public.
[2]Excludes use for lease and plant fuel.
[3]Includes Federal and State taxes while excluding county and local taxes.
[4]E85 refers to a blend of 85 percent ethanol (renewable) and 15 percent motor gasoline (nonrenewable). To address cold starting issues, the percentage of ethanol varies seasonally. The annual average ethanol content of 74 percent is used for this forecast.
[5]Sales weighted-average price for all grades. Includes Federal, State and local taxes.
[6]Kerosene-type jet fuel. Includes Federal and State taxes while excluding county and local taxes.
[7]Diesel fuel for on-road use. Includes Federal and State taxes while excluding county and local taxes.
[8]Compressed natural gas used as a vehicle fuel. Includes estimated motor vehicle fuel taxes and estimated dispensing costs or charges.
[9]Includes electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public.
[10]Weighted averages of end-use fuel prices are derived from the prices shown in each sector and the corresponding sectoral consumption.
Btu = British thermal unit.
- - = Not applicable.
Note: Data for 2006 and 2007 are model results and may differ slightly from official EIA data reports.

Sources: 2006 and 2007 prices for motor gasoline, distillate fuel oil, and jet fuel are based on prices in the Energy Information Administration (EIA), *Petroleum Marketing Annual 2007*, DOE/EIA-0487(2007) (Washington, DC, August 2008). 2006 residential and commercial natural gas delivered prices: EIA, *Natural Gas Annual 2006*, DOE/EIA-0131(2006) (Washington, DC, October 2007). 2007 residential and commercial natural gas delivered prices: EIA, *Natural Gas Monthly*, DOE/EIA-0130(2008/08) (Washington, DC, August 2008). 2006 and 2007 industrial natural gas delivered prices are estimated based on: EIA, *Manufacturing Energy Consumption Survey 1994* and industrial and wellhead prices from the *Natural Gas Annual 2006*, DOE/EIA-0131(2006) (Washington, DC, October 2007) and the *Natural Gas Monthly*, DOE/EIA-0130(2008/08) (Washington, DC, August 2008). 2006 transportation sector natural gas delivered prices are based on: EIA, *Natural Gas Annual 2006*, DOE/EIA-0131(2006) (Washington, DC, October 2007) and estimated State taxes, Federal taxes, and dispensing costs or charges. 2007 transportation sector natural gas delivered prices are model results. 2006 and 2007 electric power sector natural gas prices: EIA, *Electric Power Monthly*, DOE/EIA-0226, April 2007 and April 2008, Table 4.13.B. 2006 and 2007 coal prices based on: EIA, *Quarterly Coal Report, October-December 2007*, DOE/EIA-0121(2007/4Q) (Washington, DC, March 2008) and EIA, AEO2009 National Energy Modeling System run AEO2009.D120908A. 2006 and 2007 electricity prices: EIA, *Annual Energy Review 2007*, DOE/EIA-0384(2007) (Washington, DC, June 2008). 2006 and 2007 E85 prices derived from monthly prices in the Clean Cities Alternative Fuel Price Report. **Projections:** EIA, AEO2009 National Energy Modeling System run AEO2009.D120908A.

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

Key Indicators and Consumption	Reference Case							Annual Growth 2007-2030 (percent)
	2006	2007	2010	2015	2020	2025	2030	
Key Indicators								
Households (millions)								
Single-Family	80.80	81.74	83.61	88.69	93.63	97.66	101.57	0.9%
Multifamily	24.81	25.15	25.97	27.39	29.17	30.73	32.47	1.1%
Mobile Homes	6.89	6.85	6.73	6.75	6.96	7.03	7.09	0.2%
Total	**112.50**	**113.74**	**116.30**	**122.82**	**129.76**	**135.42**	**141.14**	**0.9%**
Average House Square Footage	**1648**	**1663**	**1701**	**1772**	**1834**	**1887**	**1934**	**0.7%**
Energy Intensity								
(million Btu per household)								
Delivered Energy Consumption	95.7	100.2	98.4	93.8	91.4	89.7	87.6	-0.6%
Total Energy Consumption	184.6	191.3	188.2	178.1	174.7	172.2	170.4	-0.5%
(thousand Btu per square foot)								
Delivered Energy Consumption	58.1	60.3	57.8	52.9	49.8	47.5	45.3	-1.2%
Total Energy Consumption	112.0	115.0	110.6	100.5	95.2	91.2	88.1	-1.2%
Delivered Energy Consumption by Fuel								
Electricity								
Space Heating	0.26	0.28	0.29	0.30	0.31	0.31	0.31	0.4%
Space Cooling	0.84	0.89	0.86	0.90	0.97	1.03	1.10	0.9%
Water Heating	0.42	0.42	0.42	0.44	0.48	0.50	0.50	0.8%
Refrigeration	0.39	0.39	0.37	0.37	0.39	0.40	0.42	0.4%
Cooking	0.10	0.11	0.11	0.12	0.13	0.13	0.14	1.3%
Clothes Dryers	0.27	0.27	0.27	0.28	0.29	0.30	0.32	0.7%
Freezers	0.08	0.08	0.08	0.08	0.08	0.09	0.09	0.4%
Lighting	0.74	0.73	0.71	0.59	0.55	0.53	0.52	-1.5%
Clothes Washers[1]	0.04	0.03	0.03	0.03	0.03	0.03	0.03	-0.9%
Dishwashers[1]	0.10	0.10	0.09	0.10	0.10	0.11	0.12	0.8%
Color Televisions and Set-Top Boxes	0.34	0.36	0.40	0.41	0.44	0.49	0.56	1.9%
Personal Computers and Related Equipment	0.14	0.15	0.18	0.19	0.20	0.21	0.23	1.7%
Furnace Fans and Boiler Circulation Pumps	0.11	0.13	0.13	0.14	0.15	0.16	0.16	1.1%
Other Uses[2]	0.78	0.82	0.85	0.92	1.01	1.10	1.19	1.7%
Delivered Energy	**4.61**	**4.75**	**4.80**	**4.85**	**5.12**	**5.39**	**5.69**	**0.8%**
Natural Gas								
Space Heating	2.85	3.21	3.27	3.34	3.39	3.42	3.40	0.3%
Space Cooling	0.00	0.00	0.00	0.00	0.00	0.00	0.00	- -
Water Heating	1.35	1.35	1.35	1.37	1.40	1.39	1.35	-0.0%
Cooking	0.22	0.22	0.22	0.23	0.24	0.25	0.26	0.7%
Clothes Dryers	0.07	0.07	0.07	0.07	0.06	0.06	0.06	-0.9%
Delivered Energy	**4.49**	**4.86**	**4.92**	**5.01**	**5.10**	**5.13**	**5.07**	**0.2%**
Distillate Fuel Oil								
Space Heating	0.59	0.66	0.62	0.57	0.53	0.50	0.46	-1.6%
Water Heating	0.12	0.12	0.10	0.08	0.06	0.06	0.05	-3.7%
Delivered Energy	**0.71**	**0.78**	**0.72**	**0.64**	**0.60**	**0.55**	**0.51**	**-1.8%**
Liquefied Petroleum Gases								
Space Heating	0.20	0.22	0.21	0.20	0.20	0.20	0.19	-0.6%
Water Heating	0.10	0.09	0.08	0.06	0.06	0.05	0.05	-2.5%
Cooking	0.03	0.03	0.03	0.03	0.04	0.04	0.04	0.6%
Other Uses[3]	0.15	0.15	0.16	0.18	0.20	0.22	0.24	1.9%
Delivered Energy	**0.49**	**0.50**	**0.49**	**0.48**	**0.49**	**0.50**	**0.52**	**0.2%**
Marketed Renewables (wood)[4]	0.39	0.43	0.43	0.46	0.48	0.49	0.50	0.7%
Other Fuels[5]	0.08	0.09	0.08	0.08	0.08	0.08	0.08	-0.5%

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

Key Indicators and Consumption	Reference Case							Annual Growth 2007-2030 (percent)
	2006	2007	2010	2015	2020	2025	2030	
Delivered Energy Consumption by End Use								
Space Heating	4.37	4.89	4.91	4.95	4.99	4.99	4.95	0.1%
Space Cooling	0.84	0.89	0.86	0.90	0.97	1.03	1.10	0.9%
Water Heating	1.99	1.98	1.95	1.95	2.00	2.01	1.95	-0.1%
Refrigeration	0.39	0.39	0.37	0.37	0.39	0.40	0.42	0.4%
Cooking	0.35	0.36	0.37	0.38	0.41	0.42	0.43	0.9%
Clothes Dryers	0.34	0.34	0.34	0.34	0.35	0.36	0.38	0.4%
Freezers	0.08	0.08	0.08	0.08	0.08	0.09	0.09	0.4%
Lighting	0.74	0.73	0.71	0.59	0.55	0.53	0.52	-1.5%
Clothes Washers[1]	0.04	0.03	0.03	0.03	0.03	0.03	0.03	-0.9%
Dishwashers[1]	0.10	0.10	0.09	0.10	0.10	0.11	0.12	0.8%
Color Televisions and Set-Top Boxes	0.34	0.36	0.40	0.41	0.44	0.49	0.56	1.9%
Personal Computers and Related Equipment	0.14	0.15	0.18	0.19	0.20	0.21	0.23	1.7%
Furnace Fans and Boiler Circulation Pumps	0.11	0.13	0.13	0.14	0.15	0.16	0.16	1.1%
Other Uses[6]	0.94	0.97	1.01	1.09	1.21	1.32	1.43	1.7%
Delivered Energy	**10.77**	**11.40**	**11.44**	**11.52**	**11.86**	**12.14**	**12.36**	**0.4%**
Electricity Related Losses	**10.00**	**10.36**	**10.44**	**10.35**	**10.81**	**11.17**	**11.69**	**0.5%**
Total Energy Consumption by End Use								
Space Heating	4.94	5.51	5.53	5.58	5.64	5.63	5.59	0.1%
Space Cooling	2.65	2.82	2.73	2.82	3.01	3.17	3.34	0.7%
Water Heating	2.89	2.90	2.87	2.88	3.01	3.05	2.98	0.1%
Refrigeration	1.24	1.23	1.18	1.16	1.20	1.23	1.29	0.2%
Cooking	0.58	0.59	0.60	0.63	0.67	0.70	0.72	0.9%
Clothes Dryers	0.92	0.92	0.92	0.94	0.96	0.98	1.03	0.5%
Freezers	0.26	0.26	0.25	0.25	0.26	0.27	0.28	0.3%
Lighting	2.35	2.33	2.27	1.85	1.73	1.63	1.59	-1.6%
Clothes Washers[1]	0.11	0.11	0.10	0.09	0.08	0.08	0.09	-1.1%
Dishwashers[1]	0.30	0.30	0.30	0.30	0.32	0.33	0.35	0.7%
Color Televisions and Set-Top Boxes	1.07	1.15	1.28	1.29	1.37	1.51	1.71	1.8%
Personal Computers and Related Equipment	0.45	0.49	0.58	0.58	0.61	0.65	0.69	1.5%
Furnace Fans and Boiler Circulation Pumps	0.36	0.41	0.42	0.44	0.47	0.49	0.50	0.9%
Other Uses[6]	2.63	2.75	2.85	3.05	3.34	3.60	3.88	1.5%
Total	**20.77**	**21.76**	**21.88**	**21.87**	**22.67**	**23.31**	**24.05**	**0.4%**
Nonmarketed Renewables[7]								
Geothermal Heat Pumps	0.00	0.00	0.00	0.01	0.01	0.02	0.02	9.1%
Solar Hot Water Heating	0.00	0.00	0.00	0.00	0.00	0.01	0.01	2.6%
Solar Photovoltaic	0.00	0.00	0.01	0.03	0.05	0.05	0.05	25.2%
Wind	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.0%
Total	**0.01**	**0.01**	**0.01**	**0.05**	**0.07**	**0.07**	**0.08**	**11.5%**

[1]Does not include water heating portion of load.
[2]Includes small electric devices, heating elements, and motors not listed above.
[3]Includes such appliances as outdoor grills and mosquito traps.
[4]Includes wood used for primary and secondary heating in wood stoves or fireplaces as reported in the *Residential Energy Consumption Survey 2005*.
[5]Includes kerosene and coal.
[6]Includes all other uses listed above.
[7]Represents delivered energy displaced.
Btu = British thermal unit.
- - = Not applicable.
Note: Totals may not equal sum of components due to independent rounding. Data for 2006 and 2007 are model results and may differ slightly from official EIA data reports.
Sources: 2006 and 2007 based on: Energy Information Administration (EIA), *Annual Energy Review 2007*, DOE/EIA-0384(2007) (Washington, DC, June 2008). **Projections:** EIA, AEO2009 National Energy Modeling System run AEO2009.D120908A.

Table A5. Commercial Sector Key Indicators and Consumption

(Quadrillion Btu per Year, Unless Otherwise Noted)

Key Indicators and Consumption	Reference Case							Annual Growth 2007-2030 (percent)
	2006	2007	2010	2015	2020	2025	2030	
Key Indicators								
Total Floorspace (billion square feet)								
Surviving	73.7	75.2	79.5	84.2	90.3	95.6	101.2	1.3%
New Additions	2.1	2.1	1.7	1.9	1.9	1.9	2.1	-0.1%
Total	**75.8**	**77.3**	**81.2**	**86.1**	**92.3**	**97.5**	**103.3**	**1.3%**
Energy Consumption Intensity (thousand Btu per square foot)								
Delivered Energy Consumption	107.9	110.0	106.7	106.3	105.0	104.3	102.9	-0.3%
Electricity Related Losses	126.9	129.3	127.5	127.1	127.6	126.3	125.5	-0.1%
Total Energy Consumption	234.8	239.3	234.2	233.4	232.6	230.7	228.4	-0.2%
Delivered Energy Consumption by Fuel								
Purchased Electricity								
Space Heating[1]	0.16	0.17	0.17	0.17	0.18	0.18	0.18	0.2%
Space Cooling[1]	0.53	0.56	0.54	0.57	0.60	0.62	0.65	0.7%
Water Heating[1]	0.10	0.10	0.09	0.10	0.10	0.10	0.10	-0.1%
Ventilation	0.48	0.49	0.53	0.59	0.64	0.68	0.71	1.6%
Cooking	0.02	0.02	0.02	0.02	0.02	0.02	0.02	-0.1%
Lighting	1.08	1.07	1.06	1.10	1.15	1.19	1.22	0.5%
Refrigeration	0.40	0.40	0.40	0.38	0.38	0.39	0.40	-0.0%
Office Equipment (PC)	0.21	0.24	0.25	0.27	0.29	0.32	0.34	1.5%
Office Equipment (non-PC)	0.19	0.21	0.26	0.32	0.38	0.41	0.43	3.2%
Other Uses[2]	1.27	1.31	1.43	1.61	1.83	2.04	2.27	2.4%
Delivered Energy	**4.43**	**4.58**	**4.75**	**5.14**	**5.57**	**5.95**	**6.31**	**1.4%**
Natural Gas								
Space Heating[1]	1.35	1.45	1.50	1.54	1.56	1.56	1.53	0.2%
Space Cooling[1]	0.04	0.04	0.04	0.04	0.04	0.04	0.04	-0.2%
Water Heating[1]	0.44	0.44	0.44	0.47	0.51	0.54	0.56	1.0%
Cooking	0.16	0.16	0.18	0.19	0.20	0.21	0.22	1.2%
Other Uses[3]	0.94	1.00	0.99	1.01	1.04	1.10	1.19	0.7%
Delivered Energy	**2.92**	**3.10**	**3.14**	**3.25**	**3.34**	**3.45**	**3.54**	**0.6%**
Distillate Fuel Oil								
Space Heating[1]	0.15	0.17	0.16	0.15	0.15	0.15	0.15	-0.5%
Water Heating[1]	0.02	0.02	0.02	0.02	0.02	0.03	0.03	0.9%
Other Uses[4]	0.22	0.22	0.18	0.17	0.17	0.17	0.17	-1.2%
Delivered Energy	**0.40**	**0.41**	**0.36**	**0.34**	**0.34**	**0.34**	**0.34**	**-0.8%**
Marketed Renewables (biomass)	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.0%
Other Fuels[5]	0.29	0.29	0.28	0.30	0.31	0.31	0.31	0.3%
Delivered Energy Consumption by End Use								
Space Heating[1]	1.66	1.79	1.83	1.86	1.89	1.89	1.86	0.2%
Space Cooling[1]	0.57	0.59	0.58	0.61	0.63	0.66	0.69	0.6%
Water Heating[1]	0.56	0.56	0.55	0.59	0.63	0.66	0.68	0.9%
Ventilation	0.48	0.49	0.53	0.59	0.64	0.68	0.71	1.6%
Cooking	0.18	0.19	0.20	0.21	0.22	0.23	0.24	1.1%
Lighting	1.08	1.07	1.06	1.10	1.15	1.19	1.22	0.5%
Refrigeration	0.40	0.40	0.40	0.38	0.38	0.39	0.40	-0.0%
Office Equipment (PC)	0.21	0.24	0.25	0.27	0.29	0.32	0.34	1.5%
Office Equipment (non-PC)	0.19	0.21	0.26	0.32	0.38	0.41	0.43	3.2%
Other Uses[6]	2.84	2.95	3.00	3.22	3.47	3.74	4.06	1.4%
Delivered Energy	**8.17**	**8.50**	**8.66**	**9.15**	**9.69**	**10.17**	**10.62**	**1.0%**

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

Key Indicators and Consumption	Reference Case							Annual Growth 2007-2030 (percent)
	2006	2007	2010	2015	2020	2025	2030	
Electricity Related Losses	**9.62**	**9.99**	**10.35**	**10.95**	**11.77**	**12.32**	**12.96**	**1.1%**
Total Energy Consumption by End Use								
Space Heating[1]	2.01	2.16	2.20	2.23	2.27	2.26	2.23	0.1%
Space Cooling[1]	1.73	1.80	1.77	1.82	1.89	1.95	2.03	0.5%
Water Heating[1]	0.77	0.77	0.76	0.80	0.83	0.86	0.87	0.6%
Ventilation	1.51	1.57	1.68	1.85	2.01	2.10	2.17	1.4%
Cooking	0.24	0.24	0.25	0.26	0.27	0.28	0.29	0.8%
Lighting	3.41	3.41	3.36	3.44	3.58	3.64	3.71	0.4%
Refrigeration	1.26	1.28	1.26	1.18	1.18	1.19	1.22	-0.2%
Office Equipment (PC)	0.68	0.77	0.80	0.85	0.91	0.98	1.03	1.3%
Office Equipment (non-PC)	0.61	0.67	0.82	1.00	1.18	1.26	1.32	3.0%
Other Uses[6]	5.59	5.82	6.11	6.66	7.33	7.96	8.71	1.8%
Total	**17.79**	**18.49**	**19.01**	**20.10**	**21.46**	**22.49**	**23.59**	**1.1%**
Nonmarketed Renewable Fuels[7]								
Solar Thermal	0.02	0.02	0.03	0.03	0.03	0.03	0.03	0.5%
Solar Photovoltaic	0.00	0.00	0.00	0.01	0.01	0.01	0.01	8.4%
Wind	0.00	0.00	0.00	0.00	0.00	0.00	0.00	13.3%
Total	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**	**0.04**	**0.04**	**2.0%**

[1]Includes fuel consumption for district services.
[2]Includes miscellaneous uses, such as service station equipment, automated teller machines, telecommunications equipment, and medical equipment.
[3]Includes miscellaneous uses, such as pumps, emergency generators, combined heat and power in commercial buildings, and manufacturing performed in commercial buildings.
[4]Includes miscellaneous uses, such as cooking, emergency generators, and combined heat and power in commercial buildings.
[5]Includes residual fuel oil, liquefied petroleum gases, coal, motor gasoline, and kerosene.
[6]Includes miscellaneous uses, such as service station equipment, automated teller machines, telecommunications equipment, medical equipment, pumps, emergency generators, combined heat and power in commercial buildings, manufacturing performed in commercial buildings, and cooking (distillate), plus residual fuel oil, liquefied petroleum gases, coal, motor gasoline, and kerosene.
[7]Represents delivered energy displaced by solar thermal space heating and water heating, and electricity generation by solar photovoltaic systems.
Btu = British thermal unit.
PC = Personal computer.
Note: Totals may not equal sum of components due to independent rounding. Data for 2006 and 2007 are model results and may differ slightly from official EIA data reports.
Sources: 2006 and 2007 based on: Energy Information Administration (EIA), *Annual Energy Review 2007*, DOE/EIA-0384(2007) (Washington, DC, June 2008). **Projections:** EIA, AEO2009 National Energy Modeling System run AEO2009.D120908A.

Table A6. Industrial Sector Key Indicators and Consumption

Key Indicators and Consumption	Reference Case							Annual Growth 2007-2030 (percent)
	2006	2007	2010	2015	2020	2025	2030	
Key Indicators								
Value of Shipments (billion 2000 dollars)								
Manufacturing	4260	4261	3963	4694	5150	5732	6671	2.0%
Nonmanufacturing	1503	1490	1277	1581	1603	1671	1780	0.8%
Total	**5763**	**5750**	**5240**	**6276**	**6753**	**7402**	**8451**	**1.7%**
Energy Prices								
(2007 dollars per million Btu)								
Liquefied Petroleum Gases	21.04	23.38	21.84	28.19	28.78	29.35	30.99	1.2%
Motor Gasoline	15.92	15.93	23.41	28.63	29.64	30.58	32.04	3.1%
Distillate Fuel Oil	15.74	16.82	16.01	22.10	22.56	23.68	25.19	1.8%
Residual Fuel Oil	9.21	10.49	15.38	20.43	20.94	21.43	22.73	3.4%
Petrochemical Feedstocks	9.26	12.60	12.09	17.06	17.63	18.09	18.95	1.8%
Asphalt and Road Oil	4.75	5.36	6.49	9.30	9.52	9.87	10.70	3.1%
Natural Gas Heat and Power	6.94	6.59	6.03	6.18	6.65	7.18	8.31	1.0%
Natural Gas Feedstocks	8.71	8.24	7.70	7.80	8.25	8.76	9.83	0.8%
Metallurgical Coal	3.64	3.61	4.37	4.40	4.40	4.55	4.41	0.9%
Other Industrial Coal	2.40	2.43	2.54	2.57	2.53	2.57	2.67	0.4%
Coal for Liquids	- -	- -	- -	1.21	1.23	1.31	1.36	- -
Electricity	18.41	18.63	18.72	18.33	19.06	20.09	21.59	0.6%
(nominal dollars per million Btu)								
Liquefied Petroleum Gases	20.49	23.38	23.00	32.62	37.17	40.49	44.93	2.9%
Motor Gasoline	15.51	15.93	24.66	33.13	38.29	42.19	46.45	4.8%
Distillate Fuel Oil	15.32	16.82	16.86	25.57	29.14	32.67	36.52	3.4%
Residual Fuel Oil	8.97	10.49	16.20	23.64	27.05	29.57	32.95	5.1%
Petrochemical Feedstocks	9.02	12.60	12.74	19.74	22.77	24.95	27.48	3.4%
Asphalt and Road Oil	4.63	5.36	6.83	10.76	12.30	13.62	15.51	4.7%
Natural Gas Heat and Power	6.76	6.59	6.35	7.15	8.59	9.91	12.05	2.7%
Natural Gas Feedstocks	8.48	8.24	8.11	9.02	10.66	12.09	14.26	2.4%
Metallurgical Coal	3.54	3.61	4.60	5.09	5.69	6.28	6.40	2.5%
Other Industrial Coal	2.34	2.43	2.67	2.98	3.27	3.55	3.88	2.0%
Coal for Liquids	- -	- -	- -	1.40	1.59	1.81	1.98	- -
Electricity	17.93	18.63	19.72	21.20	24.63	27.71	31.30	2.3%
Energy Consumption (quadrillion Btu)[1]								
Industrial Consumption Excluding Refining								
Liquefied Petroleum Gases Heat and Power	0.17	0.18	0.15	0.16	0.15	0.15	0.16	-0.6%
Liquefied Petroleum Gases Feedstocks	2.16	2.16	1.83	1.80	1.61	1.57	1.50	-1.6%
Motor Gasoline	0.36	0.36	0.34	0.35	0.34	0.34	0.36	-0.1%
Distillate Fuel Oil	1.26	1.27	1.17	1.21	1.18	1.19	1.23	-0.1%
Residual Fuel Oil	0.23	0.24	0.15	0.16	0.16	0.16	0.16	-1.7%
Petrochemical Feedstocks	1.42	1.30	1.01	1.20	1.13	1.10	1.05	-0.9%
Petroleum Coke	0.36	0.36	0.27	0.29	0.29	0.29	0.31	-0.6%
Asphalt and Road Oil	1.26	1.19	0.96	1.15	1.08	1.07	1.12	-0.3%
Miscellaneous Petroleum[2]	0.59	0.62	0.30	0.23	0.21	0.21	0.21	-4.6%
Petroleum Subtotal	7.81	7.68	6.18	6.55	6.15	6.08	6.10	-1.0%
Natural Gas Heat and Power	4.99	5.14	5.02	5.00	4.86	4.99	5.11	-0.0%
Natural Gas Feedstocks	0.58	0.55	0.51	0.52	0.50	0.49	0.44	-0.9%
Lease and Plant Fuel[3]	1.16	1.20	1.27	1.25	1.33	1.44	1.47	0.9%
Natural Gas Subtotal	6.73	6.89	6.80	6.78	6.69	6.92	7.02	0.1%
Metallurgical Coal and Coke[4]	0.66	0.62	0.56	0.55	0.50	0.49	0.49	-1.1%
Other Industrial Coal	1.19	1.15	1.18	1.10	1.09	1.10	1.10	-0.2%
Coal Subtotal	1.86	1.77	1.74	1.65	1.60	1.59	1.59	-0.5%
Renewables[5]	1.70	1.64	1.48	1.56	1.64	1.78	1.96	0.8%
Purchased Electricity	3.30	3.27	3.15	3.29	3.27	3.32	3.45	0.2%
Delivered Energy	**21.39**	**21.26**	**19.36**	**19.83**	**19.35**	**19.68**	**20.11**	**-0.2%**
Electricity Related Losses	7.16	7.13	6.86	7.01	6.91	6.88	7.09	-0.0%
Total	**28.55**	**28.40**	**26.22**	**26.83**	**26.25**	**26.57**	**27.20**	**-0.2%**

Table A6. Industrial Sector Key Indicators and Consumption (Continued)

Key Indicators and Consumption	Reference Case							Annual Growth 2007-2030 (percent)
	2006	2007	2010	2015	2020	2025	2030	
Refining Consumption								
Liquefied Petroleum Gases Heat and Power	0.01	0.01	0.03	0.01	0.02	0.00	0.00	- -
Distillate Fuel Oil	0.00	0.00	0.00	0.00	0.00	0.00	0.00	- -
Residual Fuel Oil	0.01	0.01	0.00	0.00	0.00	0.00	0.00	- -
Petroleum Coke	0.57	0.55	0.54	0.54	0.53	0.52	0.53	-0.2%
Still Gas	1.69	1.68	1.65	1.60	1.62	1.62	1.67	-0.0%
Miscellaneous Petroleum[2]	0.04	0.02	0.01	0.01	0.01	0.01	0.01	-4.8%
Petroleum Subtotal	2.32	2.27	2.24	2.16	2.17	2.15	2.20	-0.1%
Natural Gas Heat and Power	1.10	1.13	1.25	1.46	1.47	1.47	1.49	1.2%
Natural-Gas-to-Liquids Heat and Power	0.00	0.00	0.00	0.00	0.00	0.00	0.00	- -
Natural Gas Subtotal	1.10	1.13	1.25	1.46	1.47	1.47	1.49	1.2%
Other Industrial Coal	0.06	0.06	0.06	0.06	0.06	0.06	0.06	-0.2%
Coal-to-Liquids Heat and Power	0.00	0.00	0.00	0.13	0.24	0.40	0.58	- -
Coal Subtotal	0.06	0.06	0.06	0.19	0.30	0.46	0.64	10.7%
Biofuels Heat and Coproducts	0.30	0.40	0.75	0.95	1.23	1.62	1.66	6.4%
Purchased Electricity	0.15	0.16	0.19	0.21	0.22	0.21	0.22	1.4%
Delivered Energy	**3.94**	**4.03**	**4.48**	**4.97**	**5.38**	**5.92**	**6.22**	**1.9%**
Electricity Related Losses	0.32	0.35	0.41	0.44	0.46	0.44	0.46	1.2%
Total	**4.25**	**4.38**	**4.88**	**5.41**	**5.84**	**6.36**	**6.67**	**1.9%**
Total Industrial Sector Consumption								
Liquefied Petroleum Gases Heat and Power	0.18	0.19	0.19	0.17	0.17	0.15	0.16	-0.8%
Liquefied Petroleum Gases Feedstocks	2.16	2.16	1.83	1.80	1.61	1.57	1.50	-1.6%
Motor Gasoline	0.36	0.36	0.34	0.35	0.34	0.34	0.36	-0.1%
Distillate Fuel Oil	1.26	1.28	1.17	1.21	1.18	1.19	1.23	-0.1%
Residual Fuel Oil	0.24	0.25	0.15	0.16	0.16	0.16	0.16	-1.9%
Petrochemical Feedstocks	1.42	1.30	1.01	1.20	1.13	1.10	1.05	-0.9%
Petroleum Coke	0.93	0.91	0.81	0.83	0.82	0.82	0.83	-0.4%
Asphalt and Road Oil	1.26	1.19	0.96	1.15	1.08	1.07	1.12	-0.3%
Still Gas	1.69	1.68	1.65	1.60	1.62	1.62	1.67	-0.0%
Miscellaneous Petroleum[2]	0.63	0.65	0.31	0.23	0.21	0.22	0.22	-4.6%
Petroleum Subtotal	10.13	9.96	8.42	8.71	8.32	8.22	8.30	-0.8%
Natural Gas Heat and Power	6.10	6.27	6.27	6.47	6.34	6.46	6.60	0.2%
Natural-Gas-to-Liquids Heat and Power	0.00	0.00	0.00	0.00	0.00	0.00	0.00	- -
Natural Gas Feedstocks	0.58	0.55	0.51	0.52	0.50	0.49	0.44	-0.9%
Lease and Plant Fuel[3]	1.16	1.20	1.27	1.25	1.33	1.44	1.47	0.9%
Natural Gas Subtotal	7.83	8.02	8.05	8.24	8.17	8.39	8.51	0.3%
Metallurgical Coal and Coke[4]	0.66	0.62	0.56	0.55	0.50	0.49	0.49	-1.1%
Other Industrial Coal	1.25	1.21	1.24	1.16	1.15	1.16	1.16	-0.2%
Coal-to-Liquids Heat and Power	0.00	0.00	0.00	0.13	0.24	0.40	0.58	32.7%
Coal Subtotal	1.92	1.83	1.80	1.84	1.89	2.05	2.23	0.9%
Biofuels Heat and Coproducts	0.30	0.40	0.75	0.95	1.23	1.62	1.66	6.4%
Renewables[5]	1.70	1.64	1.48	1.56	1.64	1.78	1.96	0.8%
Purchased Electricity	3.45	3.43	3.34	3.50	3.48	3.54	3.67	0.3%
Delivered Energy	**25.33**	**25.29**	**23.83**	**24.79**	**24.73**	**25.60**	**26.33**	**0.2%**
Electricity Related Losses	7.48	7.49	7.27	7.45	7.36	7.32	7.55	0.0%
Total	**32.81**	**32.77**	**31.10**	**32.24**	**32.09**	**32.93**	**33.87**	**0.1%**

Table A6. Industrial Sector Key Indicators and Consumption (Continued)

Key Indicators and Consumption	Reference Case							Annual Growth 2007-2030 (percent)
	2006	2007	2010	2015	2020	2025	2030	
Energy Consumption per dollar of Shipment (thousand Btu per 2000 dollars)								
Liquefied Petroleum Gases Heat and Power	0.03	0.03	0.04	0.03	0.03	0.02	0.02	-2.4%
Liquefied Petroleum Gases Feedstocks	0.37	0.38	0.35	0.29	0.24	0.21	0.18	-3.2%
Motor Gasoline	0.06	0.06	0.07	0.06	0.05	0.05	0.04	-1.7%
Distillate Fuel Oil	0.22	0.22	0.22	0.19	0.18	0.16	0.15	-1.8%
Residual Fuel Oil	0.04	0.04	0.03	0.03	0.02	0.02	0.02	-3.5%
Petrochemical Feedstocks	0.25	0.23	0.19	0.19	0.17	0.15	0.12	-2.6%
Petroleum Coke	0.16	0.16	0.15	0.13	0.12	0.11	0.10	-2.0%
Asphalt and Road Oil	0.22	0.21	0.18	0.18	0.16	0.14	0.13	-1.9%
Still Gas	0.29	0.29	0.32	0.26	0.24	0.22	0.20	-1.7%
Miscellaneous Petroleum[2]	0.11	0.11	0.06	0.04	0.03	0.03	0.03	-6.2%
Petroleum Subtotal	1.76	1.73	1.61	1.39	1.23	1.11	0.98	-2.4%
Natural Gas Heat and Power	1.06	1.09	1.20	1.03	0.94	0.87	0.78	-1.4%
Natural-Gas-to-Liquids Heat and Power	0.00	0.00	0.00	0.00	0.00	0.00	0.00	- -
Natural Gas Feedstocks	0.10	0.10	0.10	0.08	0.07	0.07	0.05	-2.6%
Lease and Plant Fuel[3]	0.20	0.21	0.24	0.20	0.20	0.20	0.17	-0.8%
Natural Gas Subtotal	1.36	1.39	1.54	1.31	1.21	1.13	1.01	-1.4%
Metallurgical Coal and Coke[4]	0.12	0.11	0.11	0.09	0.07	0.07	0.06	-2.7%
Other Industrial Coal	0.22	0.21	0.24	0.19	0.17	0.16	0.14	-1.8%
Coal-to-Liquids Heat and Power	0.00	0.00	0.00	0.02	0.04	0.05	0.07	30.5%
Coal Subtotal	0.33	0.32	0.34	0.29	0.28	0.28	0.26	-0.8%
Biofuels Heat and Coproducts	0.05	0.07	0.14	0.15	0.18	0.22	0.20	4.6%
Renewables[5]	0.29	0.29	0.28	0.25	0.24	0.24	0.23	-0.9%
Purchased Electricity	0.60	0.60	0.64	0.56	0.52	0.48	0.43	-1.4%
Delivered Energy	**4.39**	**4.40**	**4.55**	**3.95**	**3.66**	**3.46**	**3.12**	**-1.5%**
Electricity Related Losses	1.30	1.30	1.39	1.19	1.09	0.99	0.89	-1.6%
Total	**5.69**	**5.70**	**5.94**	**5.14**	**4.75**	**4.45**	**4.01**	**-1.5%**
Industrial Combined Heat and Power								
Capacity (gigawatts)	25.69	25.42	28.84	31.46	35.01	40.93	45.71	2.6%
Generation (billion kilowatthours)	143.19	141.01	160.28	178.75	205.32	251.19	285.32	3.1%

[1]Includes energy for combined heat and power plants, except those whose primary business is to sell electricity, or electricity and heat, to the public.
[2]Includes lubricants and miscellaneous petroleum products.
[3]Represents natural gas used in well, field, and lease operations, and in natural gas processing plant machinery.
[4]Includes net coal coke imports.
[5]Includes consumption of energy produced from hydroelectric, wood and wood waste, municipal waste, and other biomass sources.
Btu = British thermal unit.
- - = Not applicable.

Note: Totals may not equal sum of components due to independent rounding. Data for 2006 and 2007 are model results and may differ slightly from official EIA data reports.

Sources: 2006 and 2007 prices for motor gasoline and distillate fuel oil are based on: Energy Information Administration (EIA), *Petroleum Marketing Annual 2007*, DOE/EIA-0487(2007) (Washington, DC, August 2008). 2006 and 2007 petrochemical feedstock and asphalt and road oil prices are based on: EIA, *State Energy Data Report 2006*, DOE/EIA-0214(2006) (Washington, DC, October 2008). 2006 and 2007 coal prices are based on: EIA, *Quarterly Coal Report, October-December 2007*, DOE/EIA-0121(2007/4Q) (Washington, DC, March 2008) and EIA, AEO2009 National Energy Modeling System run AEO2009.D120908A. 2006 and 2007 electricity prices: EIA, *Annual Energy Review 2007*, DOE/EIA-0384(2007) (Washington, DC, June 2008). 2006 and 2007 natural gas prices are based on: EIA, *Manufacturing Energy Consumption Survey 1994* and industrial and wellhead prices from the *Natural Gas Annual 2006*, DOE/EIA-0131(2006) (Washington, DC, October 2007) and the *Natural Gas Monthly*, DOE/EIA-0130(2008/08) (Washington, DC, August 2008). 2006 refining consumption values based on: *Petroleum Supply Annual 2006,* DOE/EIA-0340(2006)/1 (Washington, DC, September 2007). 2007 refining consumption based on: *Petroleum Supply Annual 2007,* DOE/EIA-0340(2007)/1 (Washington, DC, July 2008). Other 2006 and 2007 consumption values are based on: EIA, *Annual Energy Review 2007*, DOE/EIA-0384(2007) (Washington, DC, June 2008). 2006 and 2007 shipments: IHS Global Insight industry model, November 2008. **Projections:** EIA, AEO2009 National Energy Modeling System run AEO2009.D120908A.

Table A7. Transportation Sector Key Indicators and Delivered Energy Consumption

Key Indicators and Consumption	Reference Case							Annual Growth 2007-2030 (percent)
	2006	2007	2010	2015	2020	2025	2030	
Key Indicators								
Travel Indicators								
(billion vehicle miles traveled)								
Light-Duty Vehicles less than 8,500 pounds	2695	2702	2747	2869	3161	3489	3827	1.5%
Commercial Light Trucks[1]	70	72	67	78	85	93	105	1.7%
Freight Trucks greater than 10,000 pounds	244	248	232	277	303	334	378	1.9%
(billion seat miles available)								
Air	984	1036	951	1018	1138	1272	1410	1.3%
(billion ton miles traveled)								
Rail	1718	1733	1664	1846	1927	2024	2193	1.0%
Domestic Shipping	659	662	629	697	744	798	839	1.0%
Energy Efficiency Indicators								
(miles per gallon)								
Tested New Light-Duty Vehicle[2]	26.2	26.3	26.9	32.6	35.5	36.8	38.0	1.6%
New Car[2]	30.2	30.3	30.7	36.6	39.1	40.2	41.4	1.4%
New Light Truck[2]	23.1	23.1	23.6	28.3	30.7	32.1	33.1	1.6%
On-Road New Light-Duty Vehicle[3]	21.4	21.8	22.3	27.1	29.5	30.8	31.9	1.7%
New Car[3]	23.8	24.6	25.1	30.1	32.3	33.5	34.7	1.5%
New Light Truck[3]	19.4	19.4	19.8	23.8	25.8	27.0	27.8	1.6%
Light-Duty Stock[4]	20.4	20.6	20.7	22.4	24.7	27.0	28.9	1.5%
New Commercial Light Truck[1]	15.5	15.4	15.7	18.6	19.6	20.0	20.3	1.2%
Stock Commercial Light Truck[1]	14.3	14.4	14.8	16.0	17.6	18.9	19.8	1.4%
Freight Truck	6.0	6.0	6.0	6.2	6.5	6.7	6.9	0.6%
(seat miles per gallon)								
Aircraft	62.2	62.8	64.4	66.2	68.1	70.4	73.6	0.7%
(ton miles per thousand Btu)								
Rail	2.9	2.9	2.9	2.9	3.0	3.0	3.0	0.1%
Domestic Shipping	2.0	2.0	2.0	2.0	2.0	2.0	2.0	0.1%
Energy Use by Mode (quadrillion Btu)								
Light-Duty Vehicles	16.42	16.47	16.20	15.86	15.80	16.02	16.51	0.0%
Commercial Light Trucks[1]	0.62	0.62	0.57	0.61	0.61	0.62	0.67	0.3%
Bus Transportation	0.27	0.27	0.27	0.27	0.27	0.27	0.28	0.2%
Freight Trucks	5.07	5.15	4.81	5.55	5.79	6.19	6.90	1.3%
Rail, Passenger	0.04	0.05	0.05	0.05	0.05	0.06	0.06	1.3%
Rail, Freight	0.59	0.59	0.57	0.63	0.65	0.68	0.73	0.9%
Shipping, Domestic	0.34	0.34	0.32	0.35	0.37	0.40	0.42	0.9%
Shipping, International	0.84	0.88	0.80	0.89	0.90	0.90	0.91	0.1%
Recreational Boats	0.25	0.25	0.25	0.26	0.26	0.27	0.28	0.4%
Air	2.71	2.71	2.45	2.62	2.87	3.18	3.54	1.2%
Military Use	0.69	0.70	0.74	0.72	0.74	0.76	0.78	0.4%
Lubricants	0.15	0.14	0.14	0.14	0.15	0.15	0.15	0.4%
Pipeline Fuel	0.60	0.64	0.64	0.65	0.69	0.73	0.72	0.5%
Total	**28.60**	**28.82**	**27.81**	**28.60**	**29.15**	**30.23**	**31.94**	**0.4%**

Table A7. Transportation Sector Key Indicators and Delivered Energy Consumption (Continued)

Key Indicators and Consumption	Reference Case							Annual Growth 2007-2030 (percent)
	2006	2007	2010	2015	2020	2025	2030	
Energy Use by Mode								
(million barrels per day oil equivalent)								
Light-Duty Vehicles	8.61	8.74	8.72	8.61	8.69	9.00	9.35	0.3%
Commercial Light Trucks[1]	0.32	0.33	0.31	0.33	0.33	0.33	0.36	0.4%
Bus Transportation	0.13	0.13	0.13	0.13	0.13	0.13	0.14	0.2%
Freight Trucks	2.42	2.46	2.30	2.66	2.77	2.96	3.31	1.3%
Rail, Passenger	0.02	0.02	0.02	0.02	0.03	0.03	0.03	1.3%
Rail, Freight	0.28	0.28	0.27	0.30	0.31	0.32	0.35	0.9%
Shipping, Domestic	0.16	0.16	0.15	0.16	0.17	0.19	0.19	0.9%
Shipping, International	0.37	0.39	0.35	0.39	0.39	0.40	0.40	0.1%
Recreational Boats	0.13	0.13	0.14	0.14	0.14	0.15	0.15	0.5%
Air	1.31	1.31	1.19	1.27	1.39	1.54	1.71	1.2%
Military Use	0.33	0.34	0.36	0.35	0.36	0.37	0.37	0.4%
Lubricants	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.4%
Pipeline Fuel	0.30	0.32	0.32	0.33	0.35	0.37	0.36	0.5%
Total	**14.46**	**14.68**	**14.32**	**14.76**	**15.13**	**15.85**	**16.80**	**0.6%**

[1]Commercial trucks 8,500 to 10,000 pounds.
[2]Environmental Protection Agency rated miles per gallon.
[3]Tested new vehicle efficiency revised for on-road performance.
[4]Combined car and light truck "on-the-road" estimate.
Btu = British thermal unit.

Note: Totals may not equal sum of components due to independent rounding. Data for 2006 and 2007 are model results and may differ slightly from official EIA data reports.

Sources: 2006 and 2007: Energy Information Administration (EIA), *Natural Gas Annual 2006*, DOE/EIA-0131(2006) (Washington, DC, October 2007); EIA, *Annual Energy Review 2007*, DOE/EIA-0384(2007) (Washington, DC, June 2008); Federal Highway Administration, *Highway Statistics 2005* (Washington, DC, October 2006); Oak Ridge National Laboratory, *Transportation Energy Data Book: Edition 27 and Annual* (Oak Ridge, TN, 2008); National Highway Traffic and Safety Administration, *Summary of Fuel Economy Performance* (Washington, DC, March 2004); U.S. Department of Commerce, Bureau of the Census, "Vehicle Inventory and Use Survey," EC97TV (Washington, DC, October 1999); EIA, Alternatives to Traditional Transportation Fuels 2006 (Part II - User and Fuel Data), May 2008; EIA, *State Energy Data Report 2006*, DOE/EIA-0214(2006) (Washington, DC, October 2008); U.S. Department of Transportation, Research and Special Programs Administration, *Air Carrier Statistics Monthly, December 2007/2006* (Washington, DC, 2007); EIA, *Fuel Oil and Kerosene Sales 2006*, DOE/EIA-0535(2006) (Washington, DC, December 2007); and United States Department of Defense, Defense Fuel Supply Center. **Projections:** EIA, AEO2009 National Energy Modeling System run AEO2009.D120908A.

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

Supply, Disposition, and Prices	Reference Case							Annual Growth 2007-2030 (percent)
	2006	2007	2010	2015	2020	2025	2030	
Generation by Fuel Type								
Electric Power Sector[1]								
Power Only[2]								
Coal	1934	1965	2006	2065	2093	2120	2334	0.8%
Petroleum	55	57	43	44	44	45	46	-0.9%
Natural Gas[3]	618	685	629	617	687	824	772	0.5%
Nuclear Power	787	806	809	831	862	867	907	0.5%
Pumped Storage/Other[4]	1	0	1	1	1	1	1	8.8%
Renewable Sources[5]	348	314	411	473	543	581	610	2.9%
Distributed Generation (Natural Gas)	0	0	0	0	0	0	0	- -
Total	**3742**	**3827**	**3899**	**4030**	**4230**	**4438**	**4670**	**0.9%**
Combined Heat and Power[6]								
Coal	36	37	32	32	32	32	32	-0.6%
Petroleum	5	5	0	0	0	0	0	-10.0%
Natural Gas	116	129	107	112	114	114	109	-0.7%
Renewable Sources	4	4	4	4	5	5	5	0.6%
Total	**165**	**179**	**143**	**148**	**151**	**151**	**146**	**-0.9%**
Total Net Generation	**3908**	**4006**	**4042**	**4178**	**4381**	**4589**	**4816**	**0.8%**
Less Direct Use	33	34	34	33	34	34	33	-0.1%
Net Available to the Grid	**3875**	**3972**	**4009**	**4145**	**4348**	**4556**	**4783**	**0.8%**
End-Use Generation[7]								
Coal	22	19	19	25	31	39	48	4.1%
Petroleum	4	4	13	13	13	14	14	5.6%
Natural Gas	77	78	78	87	97	112	131	2.3%
Other Gaseous Fuels[8]	5	5	16	15	15	15	15	5.1%
Renewable Sources[9]	34	33	36	50	69	98	116	5.6%
Other[10]	13	13	12	12	12	12	12	-0.4%
Total	**155**	**153**	**174**	**203**	**237**	**289**	**337**	**3.5%**
Less Direct Use	124	122	142	164	188	223	261	3.4%
Total Sales to the Grid	**31**	**31**	**33**	**38**	**49**	**66**	**76**	**3.9%**
Total Electricity Generation by Fuel								
Coal	1992	2021	2057	2121	2156	2191	2415	0.8%
Petroleum	64	66	56	57	58	59	60	-0.3%
Natural Gas	812	892	814	815	898	1050	1012	0.6%
Nuclear Power	787	806	809	831	862	867	907	0.5%
Renewable Sources[5,9]	386	352	451	527	617	684	730	3.2%
Other[11]	23	22	29	28	28	28	28	1.1%
Total	**4063**	**4159**	**4217**	**4381**	**4618**	**4879**	**5153**	**0.9%**
Total Electricity Generation	**4063**	**4159**	**4217**	**4381**	**4618**	**4879**	**5153**	**0.9%**
Total Net Generation to the Grid	**3906**	**4004**	**4042**	**4183**	**4396**	**4622**	**4859**	**0.8%**
Net Imports	**18**	**31**	**24**	**17**	**18**	**14**	**28**	**-0.5%**
Electricity Sales by Sector								
Residential	1352	1392	1406	1423	1499	1581	1667	0.8%
Commercial	1300	1343	1393	1505	1632	1743	1850	1.4%
Industrial	1011	1006	979	1025	1021	1036	1077	0.3%
Transportation	6	6	7	8	10	12	15	3.7%
Total	**3669**	**3747**	**3785**	**3960**	**4162**	**4373**	**4609**	**0.9%**
Direct Use	157	156	175	198	222	257	294	2.8%
Total Electricity Use	**3826**	**3903**	**3960**	**4158**	**4384**	**4629**	**4903**	**1.0%**

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

Supply, Disposition, and Prices	Reference Case							Annual Growth 2007-2030 (percent)
	2006	2007	2010	2015	2020	2025	2030	
End-Use Prices								
(2007 cents per kilowatthour)								
Residential	10.6	10.6	10.5	10.8	11.2	11.6	12.2	0.6%
Commercial	9.7	9.6	9.3	9.3	9.6	10.0	10.6	0.4%
Industrial	6.3	6.4	6.4	6.3	6.5	6.9	7.4	0.6%
Transportation	10.4	10.5	10.4	10.3	10.1	10.8	11.7	0.5%
All Sectors Average	**9.1**	**9.1**	**9.0**	**9.1**	**9.4**	**9.8**	**10.4**	**0.6%**
(nominal cents per kilowatthour)								
Residential	10.4	10.6	11.1	12.5	14.4	16.0	17.7	2.2%
Commercial	9.4	9.6	9.8	10.7	12.4	13.8	15.3	2.1%
Industrial	6.1	6.4	6.7	7.2	8.4	9.5	10.7	2.3%
Transportation	10.1	10.5	10.9	11.9	13.0	14.9	16.9	2.1%
All Sectors Average	**8.9**	**9.1**	**9.5**	**10.5**	**12.2**	**13.6**	**15.1**	**2.2%**
Prices by Service Category								
(2007 cents per kilowatthour)								
Generation	6.0	6.0	6.0	5.9	6.2	6.6	7.3	0.8%
Transmission	0.7	0.7	0.7	0.8	0.8	0.9	0.9	1.3%
Distribution	2.4	2.4	2.4	2.4	2.4	2.4	2.3	-0.1%
(nominal cents per kilowatthour)								
Generation	5.9	6.0	6.3	6.8	8.1	9.2	10.5	2.4%
Transmission	0.7	0.7	0.8	0.9	1.1	1.2	1.3	3.0%
Distribution	2.3	2.4	2.5	2.8	3.1	3.3	3.4	1.5%
Electric Power Sector Emissions[1]								
Sulfur Dioxide (million tons)	9.40	8.95	7.51	4.17	3.86	3.78	3.74	-3.7%
Nitrogen Oxide (million tons)	3.41	3.29	2.37	2.10	2.10	2.10	2.12	-1.9%
Mercury (tons)	49.04	49.28	45.19	29.08	29.13	29.44	29.57	-2.2%

[1]Includes electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public.
[2]Includes plants that only produce electricity.
[3]Includes electricity generation from fuel cells.
[4]Includes non-biogenic municipal waste. The Energy Information Administration estimates approximately 7 billion kilowatthours of electricity were generated from a municipal waste stream containing petroleum-derived plastics and other non-renewable sources. See Energy Information Administration, *Methodology for Allocating Municipal Solid Waste to Biogenic and Non-Biogenic Energy*, (Washington, DC, May 2007).
[5]Includes conventional hydroelectric, geothermal, wood, wood waste, biogenic municipal waste, landfill gas, other biomass, solar, and wind power.
[6]Includes combined heat and power plants whose primary business is to sell electricity and heat to the public (i.e., those that report North American Industry Classification System code 22).
[7]Includes combined heat and power plants and electricity-only plants in the commercial and industrial sectors; and small on-site generating systems in the residential, commercial, and industrial sectors used primarily for own-use generation, but which may also sell some power to the grid.
[8]Includes refinery gas and still gas.
[9]Includes conventional hydroelectric, geothermal, wood, wood waste, all municipal waste, landfill gas, other biomass, solar, and wind power.
[10]Includes batteries, chemicals, hydrogen, pitch, purchased steam, sulfur, and miscellaneous technologies.
[11]Includes pumped storage, non-biogenic municipal waste, refinery gas, still gas, batteries, chemicals, hydrogen, pitch, purchased steam, sulfur, and miscellaneous technologies.
- - = Not applicable.
Note: Totals may not equal sum of components due to independent rounding. Data for 2006 and 2007 are model results and may differ slightly from official EIA data reports.
Sources: 2006 and 2007 electric power sector generation; sales to utilities; net imports; electricity sales; and emissions: Energy Information Administration (EIA), *Annual Energy Review 2007*, DOE/EIA-0384(2007) (Washington, DC, June 2008), and supporting databases. 2006 and 2007 prices: EIA, AEO2009 National Energy Modeling System run AEO2009.D120908A. **Projections**: EIA, AEO2009 National Energy Modeling System run AEO2009.D120908A.

Table A9. Electricity Generating Capacity
(Gigawatts)

Net Summer Capacity[1]	Reference Case 2006	2007	2010	2015	2020	2025	2030	Annual Growth 2007-2030 (percent)
Electric Power Sector[2]								
Power Only[3]								
Coal	305.2	306.7	316.4	321.5	322.4	323.8	347.9	0.6%
Oil and Natural Gas Steam[4]	119.3	118.4	118.0	101.4	101.4	101.4	100.1	-0.7%
Combined Cycle	144.7	149.2	163.0	163.9	170.3	197.5	205.2	1.4%
Combustion Turbine/Diesel	128.1	130.4	139.2	139.1	152.9	178.7	198.1	1.8%
Nuclear Power[5]	100.2	100.5	101.2	104.1	108.4	108.4	112.6	0.5%
Pumped Storage	21.5	21.5	21.5	21.5	21.5	21.5	21.5	0.0%
Fuel Cells	0.0	0.0	0.0	0.0	0.0	0.0	0.0	- -
Renewable Sources[6]	95.5	100.8	114.9	116.9	121.7	129.0	138.2	1.4%
Distributed Generation[7]	0.0	0.0	0.0	0.0	0.0	0.1	0.3	- -
Total	**914.5**	**927.5**	**974.2**	**968.4**	**998.5**	**1060.4**	**1123.8**	**0.8%**
Combined Heat and Power[8]								
Coal	4.6	4.6	4.6	4.6	4.6	4.6	4.6	0.0%
Oil and Natural Gas Steam[4]	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.0%
Combined Cycle	31.8	31.8	31.8	32.5	32.5	32.5	32.5	0.1%
Combustion Turbine/Diesel	2.9	2.9	2.9	2.9	2.9	2.9	2.9	0.0%
Renewable Sources[6]	0.6	0.7	0.7	0.7	0.7	0.7	0.7	0.0%
Total	**40.3**	**40.3**	**40.4**	**41.0**	**41.0**	**41.0**	**41.0**	**0.1%**
Cumulative Planned Additions[9]								
Coal	0.0	0.0	11.3	17.0	17.0	17.0	17.0	- -
Oil and Natural Gas Steam[4]	0.0	0.0	0.0	0.0	0.0	0.0	0.0	- -
Combined Cycle	0.0	0.0	13.8	15.3	15.3	15.3	15.3	- -
Combustion Turbine/Diesel	0.0	0.0	3.2	3.2	3.2	3.2	3.2	- -
Nuclear Power	0.0	0.0	0.0	1.2	1.2	1.2	1.2	- -
Pumped Storage	0.0	0.0	0.0	0.0	0.0	0.0	0.0	- -
Fuel Cells	0.0	0.0	0.0	0.0	0.0	0.0	0.0	- -
Renewable Sources[6]	0.0	0.0	9.7	9.8	9.9	10.0	10.1	- -
Distributed Generation[7]	0.0	0.0	0.0	0.0	0.0	0.0	0.0	- -
Total	**0.0**	**0.0**	**38.0**	**46.5**	**46.6**	**46.7**	**46.8**	**- -**
Cumulative Unplanned Additions[9]								
Coal	0.0	0.0	0.0	0.0	1.0	2.4	26.6	- -
Oil and Natural Gas Steam[4]	0.0	0.0	0.0	0.0	0.0	0.0	0.0	- -
Combined Cycle	0.0	0.0	0.0	0.0	6.4	33.6	41.3	- -
Combustion Turbine/Diesel	0.0	0.0	5.9	10.8	24.6	50.4	69.8	- -
Nuclear Power	0.0	0.0	0.0	0.0	3.3	3.3	11.9	- -
Pumped Storage	0.0	0.0	0.0	0.0	0.0	0.0	0.0	- -
Fuel Cells	0.0	0.0	0.0	0.0	0.0	0.0	0.0	- -
Renewable Sources[6]	0.0	0.0	4.4	6.4	11.0	18.3	27.3	- -
Distributed Generation[7]	0.0	0.0	0.0	0.0	0.0	0.1	0.3	- -
Total	**0.0**	**0.0**	**10.3**	**17.1**	**46.3**	**108.1**	**177.1**	**- -**
Cumulative Electric Power Sector Additions	**0.0**	**0.0**	**48.3**	**63.6**	**92.9**	**154.8**	**223.9**	**- -**
Cumulative Retirements[10]								
Coal	0.0	0.0	1.6	2.1	2.3	2.3	2.3	- -
Oil and Natural Gas Steam[4]	0.0	0.0	0.4	17.0	17.0	17.0	18.3	- -
Combined Cycle	0.0	0.0	0.0	0.0	0.0	0.0	0.0	- -
Combustion Turbine/Diesel	0.0	0.0	0.3	5.3	5.3	5.3	5.3	- -
Nuclear Power	0.0	0.0	0.0	0.0	0.0	0.0	4.4	- -
Pumped Storage	0.0	0.0	0.0	0.0	0.0	0.0	0.0	- -
Fuel Cells	0.0	0.0	0.0	0.0	0.0	0.0	0.0	- -
Renewable Sources[6]	0.0	0.0	0.0	0.0	0.0	0.0	0.0	- -
Total	**0.0**	**0.0**	**2.3**	**24.4**	**24.5**	**24.5**	**30.2**	**- -**
Total Electric Power Sector Capacity	**954.8**	**967.8**	**1014.5**	**1009.4**	**1039.5**	**1101.4**	**1164.9**	**0.8%**

Table A9. Electricity Generating Capacity (Continued)
(Gigawatts)

Net Summer Capacity[1]	Reference Case 2006	2007	2010	2015	2020	2025	2030	Annual Growth 2007-2030 (percent)
End-Use Generators[11]								
Coal	4.0	4.0	4.0	4.8	5.6	6.7	7.9	3.0%
Petroleum	1.2	1.3	2.6	2.6	2.6	2.6	2.7	3.3%
Natural Gas	14.1	14.0	13.8	15.1	16.4	18.3	21.0	1.8%
Other Gaseous Fuels	1.8	1.5	3.9	3.7	3.7	3.7	3.7	4.2%
Renewable Sources[6]	6.0	6.1	7.5	13.6	18.1	22.4	26.4	6.5%
Other	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.0%
Total	**27.9**	**27.8**	**32.6**	**40.6**	**47.3**	**54.5**	**62.6**	**3.6%**
Cumulative Capacity Additions[9]	**0.0**	**0.0**	**4.8**	**12.8**	**19.5**	**26.7**	**34.8**	**- -**

[1]Net summer capacity is the steady hourly output that generating equipment is expected to supply to system load (exclusive of auxiliary power), as demonstrated by tests during summer peak demand.
[2]Includes electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public.
[3]Includes plants that only produce electricity. Includes capacity increases (uprates) at existing units.
[4]Includes oil-, gas-, and dual-fired capacity.
[5]Nuclear capacity includes 3.4 gigawatts of uprates through 2030.
[6]Includes conventional hydroelectric, geothermal, wood, wood waste, all municipal waste, landfill gas, other biomass, solar, and wind power. Facilities co-firing biomass and coal are classified as coal.
[7]Primarily peak load capacity fueled by natural gas.
[8]Includes combined heat and power plants whose primary business is to sell electricity and heat to the public (i.e., those that report North American Industry Classification System code 22).
[9]Cumulative additions after December 31, 2007.
[10]Cumulative retirements after December 31, 2007.
[11]Includes combined heat and power plants and electricity-only plants in the commercial and industrial sectors; and small on-site generating systems in the residential, commercial, and industrial sectors used primarily for own-use generation, but which may also sell some power to the grid.
- - = Not applicable.
Note: Totals may not equal sum of components due to independent rounding. Data for 2006 and 2007 are model results and may differ slightly from official EIA data reports.
Sources: 2006 and 2007 capacity and projected planned additions: Energy Information Administration (EIA), Form EIA-860, "Annual Electric Generator Report" (preliminary). **Projections:** EIA, AEO2009 National Energy Modeling System run AEO2009.D120908A.

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

Electricity Trade	Reference Case							Annual Growth 2007-2030 (percent)
	2006	2007	2010	2015	2020	2025	2030	
Interregional Electricity Trade								
Gross Domestic Sales								
Firm Power	123.1	124.5	118.7	110.9	81.8	44.9	37.6	-5.1%
Economy	151.1	116.7	207.9	232.3	232.0	204.6	186.5	2.1%
Total	**274.2**	**241.3**	**326.6**	**343.2**	**313.8**	**249.5**	**224.0**	**-0.3%**
Gross Domestic Sales (million 2007 dollars)								
Firm Power	7051.4	7133.1	6799.0	6353.0	4683.5	2574.5	2152.7	-5.1%
Economy	8652.1	7235.0	11340.4	12499.1	12766.6	12674.0	12768.4	2.5%
Total	**15703.6**	**14368.1**	**18139.4**	**18852.1**	**17450.1**	**15248.5**	**14921.1**	**0.2%**
International Electricity Trade								
Imports from Canada and Mexico								
Firm Power	13.7	15.8	16.6	12.0	7.3	1.5	0.4	-14.9%
Economy	28.8	35.6	29.3	27.6	31.4	31.5	46.0	1.1%
Total	**42.4**	**51.4**	**45.9**	**39.6**	**38.7**	**33.1**	**46.4**	**-0.4%**
Exports to Canada and Mexico								
Firm Power	3.2	3.9	0.9	0.9	0.5	0.1	0.0	- -
Economy	21.4	16.2	20.6	21.3	20.4	18.5	18.5	0.6%
Total	**24.6**	**20.1**	**21.5**	**22.1**	**20.9**	**18.6**	**18.5**	**-0.4%**

- - = Not applicable.

Note: Totals may not equal sum of components due to independent rounding. Data for 2006 and 2007 are model results and may differ slightly from official EIA data reports. Firm Power Sales are capacity sales, meaning the delivery of the power is scheduled as part of the normal operating conditions of the affected electric systems. Economy Sales are subject to curtailment or cessation of delivery by the supplier in accordance with prior agreements or under specified conditions.

Sources: 2006 and 2007 interregional firm electricity trade data: North American Electric Reliability Council (NERC), Electricity Sales and Demand Database 2007. 2006 and 2007 Mexican electricity trade data: Energy Information Administration (EIA), *Electric Power Annual 2007* DOE/EIA-0348(2007) (Washington, DC, December 2008). 2006 Canadian international electricity trade data: National Energy Board, *Annual Report 2006*. 2007 Canadian electricity trade data: National Energy Board, *Annual Report 2007*. **Projections:** EIA, AEO2009 National Energy Modeling System run AEO2009.D120908A.

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

Supply and Disposition	Reference Case							Annual Growth 2007-2030 (percent)
	2006	2007	2010	2015	2020	2025	2030	
Crude Oil								
Domestic Crude Production[1]	5.10	5.07	5.62	5.72	6.48	7.21	7.37	1.6%
Alaska	0.74	0.72	0.69	0.51	0.72	0.77	0.57	-1.0%
Lower 48 States	4.36	4.35	4.93	5.21	5.76	6.44	6.80	2.0%
Net Imports	10.09	10.00	8.10	8.10	7.29	6.66	6.95	-1.6%
Gross Imports	10.12	10.03	8.13	8.13	7.33	6.70	6.99	-1.6%
Exports	0.03	0.03	0.03	0.03	0.03	0.04	0.04	1.6%
Other Crude Supply[2]	0.05	0.09	0.00	0.00	0.00	0.00	0.00	- -
Total Crude Supply	**15.24**	**15.16**	**13.72**	**13.83**	**13.77**	**13.87**	**14.32**	**-0.2%**
Other Supply								
Natural Gas Plant Liquids	1.74	1.78	1.91	1.89	1.91	1.93	1.92	0.3%
Net Product Imports	2.31	2.09	1.66	1.64	1.49	1.35	1.40	-1.7%
Gross Refined Product Imports[3]	2.17	1.94	1.64	1.53	1.60	1.51	1.54	-1.0%
Unfinished Oil Imports	0.69	0.72	0.58	0.59	0.58	0.60	0.65	-0.4%
Blending Component Imports	0.68	0.75	0.62	0.75	0.66	0.67	0.69	-0.4%
Exports	1.22	1.32	1.18	1.23	1.35	1.43	1.47	0.5%
Refinery Processing Gain[4]	0.99	1.00	0.97	0.96	0.93	0.89	0.86	-0.6%
Other Inputs	0.41	0.74	1.22	1.66	1.98	2.63	3.08	6.4%
Ethanol	0.36	0.45	0.84	1.07	1.28	1.68	1.91	6.5%
Domestic Production	0.32	0.43	0.84	1.06	1.24	1.43	1.43	5.4%
Net Imports	0.05	0.02	-0.00	0.01	0.04	0.25	0.49	14.5%
Biodiesel	0.02	0.03	0.06	0.10	0.10	0.12	0.13	6.2%
Domestic Production	0.02	0.03	0.06	0.10	0.10	0.12	0.13	6.2%
Net Imports	0.00	0.00	0.00	0.00	0.00	0.00	0.00	- -
Liquids from Gas	0.00	0.00	0.00	0.00	0.00	0.00	0.00	- -
Liquids from Coal	0.00	0.00	0.00	0.06	0.10	0.18	0.26	- -
Liquids from Biomass	0.00	0.00	0.00	0.01	0.07	0.24	0.33	- -
Other[5]	0.03	0.26	0.32	0.42	0.42	0.42	0.45	2.4%
Total Primary Supply[6]	**20.70**	**20.77**	**19.48**	**19.98**	**20.08**	**20.68**	**21.59**	**0.2%**
Liquid Fuels Consumption								
by Fuel								
Liquefied Petroleum Gases	2.05	2.09	1.99	1.95	1.82	1.78	1.74	-0.8%
E85[7]	0.00	0.00	0.00	0.24	0.58	1.17	1.50	37.1%
Motor Gasoline[8]	9.25	9.29	9.34	8.97	8.60	8.15	8.04	-0.6%
Jet Fuel[9]	1.63	1.62	1.45	1.52	1.65	1.81	1.99	0.9%
Distillate Fuel Oil[10]	4.17	4.20	4.08	4.46	4.62	4.91	5.42	1.1%
Diesel	3.21	3.47	3.47	3.89	4.06	4.38	4.91	1.5%
Residual Fuel Oil	0.69	0.72	0.63	0.69	0.70	0.71	0.72	-0.0%
Other[11]	2.86	2.74	2.19	2.31	2.24	2.22	2.25	-0.8%
by Sector								
Residential and Commercial	1.06	1.11	1.05	1.00	0.99	0.98	0.97	-0.6%
Industrial[12]	5.32	5.26	4.46	4.57	4.34	4.28	4.28	-0.9%
Transportation	14.21	14.25	13.96	14.36	14.65	15.27	16.18	0.6%
Electric Power[13]	0.29	0.30	0.22	0.22	0.23	0.23	0.23	-1.0%
Total	**20.65**	**20.65**	**19.69**	**20.16**	**20.21**	**20.76**	**21.67**	**0.2%**
Discrepancy[14]	**0.04**	**0.12**	**-0.20**	**-0.17**	**-0.13**	**-0.08**	**-0.08**	**- -**

Table A11. Liquid Fuels Supply and Disposition (Continued)
(Million Barrels per Day, Unless Otherwise Noted)

Supply and Disposition	Reference Case							Annual Growth 2007-2030 (percent)
	2006	2007	2010	2015	2020	2025	2030	
Domestic Refinery Distillation Capacity[15]	17.3	17.4	18.0	18.1	18.2	18.3	18.4	0.2%
Capacity Utilization Rate (percent)[16]	90.0	89.0	77.8	77.7	77.1	77.4	79.2	-0.5%
Net Import Share of Product Supplied (percent)	60.2	58.3	50.1	48.8	44.0	39.9	40.9	-1.5%
Net Expenditures for Imported Crude Oil and Petroleum Products (billion 2007 dollars)	272.80	280.13	261.60	360.62	344.32	329.89	376.65	1.3%

[1]Includes lease condensate.
[2]Strategic petroleum reserve stock additions plus unaccounted for crude oil and crude stock withdrawals minus crude product supplied.
[3]Includes other hydrocarbons and alcohols.
[4]The volumetric amount by which total output is greater than input due to the processing of crude oil into products which, in total, have a lower specific gravity than the crude oil processed.
[5]Includes petroleum product stock withdrawals; and domestic sources of other blending components, other hydrocarbons, ethers, and renewable feedstocks for the on-site production of diesel and gasoline.
[6]Total crude supply plus natural gas plant liquids, other inputs, refinery processing gain, and net product imports.
[7]E85 refers to a blend of 85 percent ethanol (renewable) and 15 percent motor gasoline (nonrenewable). To address cold starting issues, the percentage of ethanol varies seasonally. The annual average ethanol content of 74 percent is used for this forecast.
[8]Includes ethanol and ethers blended into gasoline.
[9]Includes only kerosene type.
[10]Includes distillate fuel oil and kerosene from petroleum and biomass feedstocks.
[11]Includes aviation gasoline, petrochemical feedstocks, lubricants, waxes, asphalt, road oil, still gas, special naphthas, petroleum coke, crude oil product supplied, methanol, liquid hydrogen,and miscellaneous petroleum products.
[12]Includes consumption for combined heat and power, which produces electricity and other useful thermal energy.
[13]Includes consumption of energy by electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public. Includes small power producers and exempt wholesale generators.
[14]Balancing item. Includes unaccounted for supply, losses, and gains.
[15]End-of-year operable capacity.
[16]Rate is calculated by dividing the gross annual input to atmospheric crude oil distillation units by their operable refining capacity in barrels per calendar day.
- - = Not applicable.
Note: Totals may not equal sum of components due to independent rounding. Data for 2006 and 2007 are model results and may differ slightly from official EIA data reports.
Sources: 2006 and 2007 petroleum product supplied based on: Energy Information Administration (EIA), *Annual Energy Review 2007*, DOE/EIA-0384(2007) (Washington, DC, June 2008). Other 2006 data: EIA, *Petroleum Supply Annual 2006,* DOE/EIA-0340(2006)/1 (Washington, DC, September 2007). Other 2007 data: EIA, *Petroleum Supply Annual 2007,* DOE/EIA-0340(2007)/1 (Washington, DC, July 2008). **Projections:** EIA, AEO2009 National Energy Modeling System run AEO2009.D120908A.

Table A12. Petroleum Product Prices
(2007 Cents per Gallon, Unless Otherwise Noted)

Sector and Fuel	Reference Case							Annual Growth 2007-2030 (percent)
	2006	2007	2010	2015	2020	2025	2030	
Crude Oil Prices (2007 dollars per barrel)								
Imported Low Sulfur Light Crude Oil[1]	67.82	72.33	80.16	110.49	115.45	121.94	130.43	2.6%
Imported Crude Oil[1]	60.70	63.83	77.56	108.52	112.05	115.33	124.60	3.0%
Delivered Sector Product Prices								
Residential								
Liquefied Petroleum Gases	205.0	213.6	221.1	275.6	281.1	285.9	300.2	1.5%
Distillate Fuel Oil	256.1	272.7	259.2	327.1	334.3	344.6	369.9	1.3%
Commercial								
Distillate Fuel Oil	207.7	221.7	222.8	298.3	304.9	318.0	340.4	1.9%
Residual Fuel Oil	132.9	152.9	164.2	241.3	249.7	255.6	269.1	2.5%
Residual Fuel Oil (2007 dollars per barrel)	55.84	64.22	68.96	101.34	104.88	107.34	113.04	2.5%
Industrial[2]								
Liquefied Petroleum Gases	180.6	199.9	186.7	241.1	246.0	250.9	265.0	1.2%
Distillate Fuel Oil	217.8	232.3	220.2	303.3	309.6	325.0	345.8	1.7%
Residual Fuel Oil	137.9	157.1	230.2	305.9	313.4	320.8	340.2	3.4%
Residual Fuel Oil (2007 dollars per barrel)	57.92	65.98	96.70	128.46	131.64	134.74	142.89	3.4%
Transportation								
Liquefied Petroleum Gases	191.4	213.8	219.5	273.9	278.9	283.2	297.3	1.4%
Ethanol (E85)[3]	242.1	253.0	241.7	242.0	278.0	282.2	285.5	0.5%
Ethanol Wholesale Price	257.0	212.4	192.8	210.8	201.1	189.8	193.8	-0.4%
Motor Gasoline[4]	270.7	282.2	283.9	347.7	359.9	371.1	388.4	1.4%
Jet Fuel[5]	205.8	217.3	216.5	290.0	299.1	310.2	332.4	1.9%
Diesel Fuel (distillate fuel oil)[6]	278.6	287.0	274.9	352.7	356.8	372.2	391.7	1.4%
Residual Fuel Oil	122.8	140.0	181.1	255.6	261.4	271.5	294.1	3.3%
Residual Fuel Oil (2007 dollars per barrel)	51.59	58.80	76.07	107.37	109.80	114.01	123.54	3.3%
Electric Power[7]								
Distillate Fuel Oil	191.0	204.9	209.2	276.0	283.6	295.2	320.5	2.0%
Residual Fuel Oil	125.4	125.4	197.7	272.3	277.7	288.3	309.5	4.0%
Residual Fuel Oil (2007 dollars per barrel)	52.67	52.67	83.03	114.35	116.64	121.08	129.98	4.0%
Refined Petroleum Product Prices[8]								
Liquefied Petroleum Gases	134.4	158.5	179.2	229.4	235.7	240.6	254.5	2.1%
Motor Gasoline[4]	269.0	280.2	283.9	347.7	359.9	371.1	388.4	1.4%
Jet Fuel[5]	205.8	217.3	216.5	290.0	299.1	310.2	332.4	1.9%
Distillate Fuel Oil	264.3	274.5	260.9	341.5	346.8	362.5	383.2	1.5%
Residual Fuel Oil	126.1	138.4	189.6	264.0	269.8	279.5	301.1	3.4%
Residual Fuel Oil (2007 dollars per barrel)	52.97	58.15	79.62	110.88	113.34	117.40	126.47	3.4%
Average	**235.1**	**249.1**	**254.9**	**321.6**	**331.1**	**342.4**	**361.4**	**1.6%**

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

Sector and Fuel	Reference Case							Annual Growth 2007-2030 (percent)
	2006	2007	2010	2015	2020	2025	2030	
Crude Oil Prices (nominal dollars per barrel)								
Imported Low Sulfur Light Crude Oil[1]	66.04	72.33	84.42	127.84	149.14	168.24	189.10	4.3%
Imported Crude Oil[1]	59.10	63.83	81.69	125.57	144.74	159.11	180.66	4.6%
Delivered Sector Product Prices								
Residential								
Liquefied Petroleum Gases	199.6	213.6	232.9	318.9	363.1	394.4	435.2	3.1%
Distillate Fuel Oil	249.4	272.7	273.0	378.5	431.8	475.4	536.3	3.0%
Commercial								
Distillate Fuel Oil	202.2	221.7	234.6	345.1	393.8	438.7	493.5	3.5%
Residual Fuel Oil	129.5	152.9	172.9	279.2	322.6	352.6	390.2	4.2%
Residual Fuel Oil (nominal dollars per barrel)	54.37	64.22	72.63	117.26	135.48	148.09	163.89	4.2%
Industrial[2]								
Liquefied Petroleum Gases	175.9	199.9	196.6	278.9	317.8	346.2	384.2	2.9%
Distillate Fuel Oil	212.1	232.3	231.9	351.0	400.0	448.4	501.4	3.4%
Residual Fuel Oil	134.3	157.1	242.5	353.9	404.9	442.6	493.3	5.1%
Residual Fuel Oil (nominal dollars per barrel)	56.40	65.98	101.84	148.64	170.06	185.89	207.17	5.1%
Transportation								
Liquefied Petroleum Gases	186.3	213.8	231.2	316.9	360.3	390.8	431.0	3.1%
Ethanol (E85)[3]	235.7	253.0	254.5	280.0	359.1	389.4	414.0	2.2%
Ethanol Wholesale Price	250.2	212.4	203.1	243.9	259.8	261.9	280.9	1.2%
Motor Gasoline[4]	263.6	282.2	299.0	402.4	464.9	512.0	563.1	3.0%
Jet Fuel[5]	200.4	217.3	228.0	335.6	386.4	428.0	482.0	3.5%
Diesel Fuel (distillate fuel oil)[6]	271.3	287.0	289.6	408.1	460.9	513.6	567.9	3.0%
Residual Fuel Oil	119.6	140.0	190.8	295.8	337.7	374.5	426.5	5.0%
Residual Fuel Oil (nominal dollars per barrel)	50.24	58.80	80.12	124.24	141.83	157.30	179.11	5.0%
Electric Power[7]								
Distillate Fuel Oil	186.0	204.9	220.4	319.3	366.4	407.3	464.7	3.6%
Residual Fuel Oil	122.1	125.4	208.2	315.0	358.8	397.7	448.7	5.7%
Residual Fuel Oil (nominal dollars per barrel)	51.29	52.67	87.45	132.32	150.68	167.04	188.44	5.7%
Refined Petroleum Product Prices[8]								
Liquefied Petroleum Gases	130.9	158.5	188.7	265.4	304.5	331.9	369.1	3.7%
Motor Gasoline[4]	261.9	280.2	299.0	402.3	464.9	512.0	563.1	3.1%
Jet Fuel[5]	200.4	217.3	228.0	335.6	386.4	428.0	482.0	3.5%
Distillate Fuel Oil	257.3	274.5	274.7	395.2	448.0	500.1	555.7	3.1%
Residual Fuel Oil	122.8	138.4	199.7	305.5	348.6	385.6	436.6	5.1%
Residual Fuel Oil (nominal dollars per barrel)	51.58	58.15	83.86	128.30	146.41	161.97	183.36	5.1%
Average	**228.9**	**249.1**	**268.5**	**372.1**	**427.7**	**472.4**	**524.0**	**3.3%**

[1]Weighted average price delivered to U.S. refiners.
[2]Includes energy for combined heat and power plants, except those whose primary business is to sell electricity, or electricity and heat, to the public.
[3]E85 refers to a blend of 85 percent ethanol (renewable) and 15 percent motor gasoline (nonrenewable). To address cold starting issues, the percentage of ethanol varies seasonally. The annual average ethanol content of 74 percent is used for this forecast.
[4]Sales weighted-average price for all grades. Includes Federal, State and local taxes.
[5]Includes only kerosene type.
[6]Diesel fuel for on-road use. Includes Federal and State taxes while excluding county and local taxes.
[7]Includes electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public. Includes small power producers and exempt wholesale generators.
[8]Weighted averages of end-use fuel prices are derived from the prices in each sector and the corresponding sectoral consumption.
Note: Data for 2006 and 2007 are model results and may differ slightly from official EIA data reports.
Sources: 2006 and 2007 imported low sulfur light crude oil price: Energy Information Administration (EIA), Form EIA-856, “Monthly Foreign Crude Oil Acquisition Report.” 2006 and 2007 imported crude oil price: EIA, *Annual Energy Review 2007*, DOE/EIA-0384(2007) (Washington, DC, June 2008). 2006 and 2007 prices for motor gasoline, distillate fuel oil, and jet fuel are based on: EIA, *Petroleum Marketing Annual 2007*, DOE/EIA-0487(2007) (Washington, DC, August 2008). 2006 and 2007 residential, commercial, industrial, and transportation sector petroleum product prices are derived from: EIA, Form EIA-782A, “Refiners’/Gas Plant Operators’ Monthly Petroleum Product Sales Report.” 2006 and 2007 electric power prices based on: Federal Energy Regulatory Commission, FERC Form 423, “Monthly Report of Cost and Quality of Fuels for Electric Plants.” 2006 and 2007 E85 prices derived from monthly prices in the Clean Cities Alternative Fuel Price Report. 2006 and 2007 wholesale ethanol prices derived from Bloomburg U.S. average rack price. **Projections:** EIA, AEO2009 National Energy Modeling System run AEO2009.D120908A.

Table A13. Natural Gas Supply, Disposition, and Prices
(Trillion Cubic Feet per Year, Unless Otherwise Noted)

Supply, Disposition, and Prices	Reference Case							Annual Growth 2007-2030 (percent)
	2006	2007	2010	2015	2020	2025	2030	
Production								
Dry Gas Production[1]	18.48	19.30	20.38	20.31	21.48	23.22	23.60	0.9%
Supplemental Natural Gas[2]	0.07	0.06	0.06	0.06	0.06	0.06	0.06	0.2%
Net Imports	**3.46**	**3.79**	**2.50**	**2.36**	**1.86**	**1.35**	**0.66**	**-7.3%**
Pipeline[3]	2.94	3.06	2.02	1.11	0.48	0.15	-0.18	- -
Liquefied Natural Gas	0.52	0.73	0.47	1.25	1.38	1.20	0.85	0.7%
Total Supply	**22.00**	**23.15**	**22.94**	**22.73**	**23.40**	**24.64**	**24.33**	**0.2%**
Consumption by Sector								
Residential	4.37	4.72	4.79	4.87	4.96	4.99	4.93	0.2%
Commercial	2.84	3.01	3.06	3.16	3.25	3.36	3.44	0.6%
Industrial[4]	6.49	6.63	6.59	6.80	6.65	6.76	6.85	0.1%
Natural-Gas-to-Liquids Heat and Power[5]	0.00	0.00	0.00	0.00	0.00	0.00	0.00	- -
Natural Gas to Liquids Production[6]	0.00	0.00	0.00	0.00	0.00	0.00	0.00	- -
Electric Power[7]	6.22	6.87	6.25	6.04	6.54	7.38	6.93	0.0%
Transportation[8]	0.02	0.02	0.03	0.05	0.07	0.08	0.09	6.0%
Pipeline Fuel	0.58	0.62	0.62	0.63	0.67	0.71	0.70	0.5%
Lease and Plant Fuel[9]	1.12	1.17	1.24	1.22	1.29	1.40	1.43	0.9%
Total	**21.65**	**23.05**	**22.57**	**22.77**	**23.43**	**24.67**	**24.36**	**0.2%**
Discrepancy[10]	**0.35**	**0.09**	**0.37**	**-0.03**	**-0.03**	**-0.03**	**-0.03**	**- -**
Natural Gas Prices								
(2007 dollars per million Btu)								
Henry Hub Spot Price	6.91	6.96	6.66	6.90	7.43	8.08	9.25	1.2%
Average Lower 48 Wellhead Price[11]	6.48	6.22	5.88	6.10	6.56	7.13	8.17	1.2%
(2007 dollars per thousand cubic feet)								
Average Lower 48 Wellhead Price[11]	6.66	6.39	6.05	6.27	6.75	7.33	8.40	1.2%
Delivered Prices								
(2007 dollars per thousand cubic feet)								
Residential	14.08	13.05	12.43	12.32	12.85	13.43	14.71	0.5%
Commercial	12.23	11.30	10.84	10.86	11.44	12.07	13.32	0.7%
Industrial[4]	8.18	7.73	7.10	7.21	7.69	8.22	9.33	0.8%
Electric Power[7]	7.25	7.22	6.77	6.90	7.35	7.95	8.94	0.9%
Transportation[12]	16.49	15.89	15.32	15.13	15.31	15.70	16.70	0.2%
Average[13]	**9.77**	**9.26**	**8.80**	**8.88**	**9.37**	**9.88**	**11.05**	**0.8%**

Table A13. Natural Gas Supply, Disposition, and Prices (Continued)
(Trillion Cubic Feet per Year, Unless Otherwise Noted)

Supply, Disposition, and Prices	Reference Case							Annual Growth 2007-2030 (percent)
	2006	2007	2010	2015	2020	2025	2030	
Natural Gas Prices								
(nominal dollars per million Btu)								
Henry Hub Spot Price	6.73	6.96	7.01	7.99	9.60	11.14	13.42	2.9%
Average Lower 48 Wellhead Price[11]	6.31	6.22	6.19	7.06	8.48	9.84	11.85	2.8%
(nominal dollars per thousand cubic feet)								
Average Lower 48 Wellhead Price[11]	6.49	6.39	6.37	7.26	8.72	10.12	12.18	2.8%
Delivered Prices								
(nominal dollars per thousand cubic feet)								
Residential	13.71	13.05	13.09	14.25	16.60	18.53	21.33	2.2%
Commercial	11.91	11.30	11.42	12.57	14.77	16.66	19.31	2.4%
Industrial[4]	7.96	7.73	7.48	8.34	9.93	11.33	13.52	2.5%
Electric Power[7]	7.06	7.22	7.13	7.99	9.49	10.97	12.96	2.6%
Transportation[12]	16.06	15.89	16.13	17.51	19.78	21.67	24.21	1.8%
Average[13]	**9.51**	**9.26**	**9.26**	**10.28**	**12.10**	**13.63**	**16.02**	**2.4%**

[1]Marketed production (wet) minus extraction losses.
[2]Synthetic natural gas, propane air, coke oven gas, refinery gas, biomass gas, air injected for Btu stabilization, and manufactured gas commingled and distributed with natural gas.
[3]Includes any natural gas regasified in the Bahamas and transported via pipeline to Florida, as well as gas from Canada and Mexico.
[4]Includes energy for combined heat and power plants, except those whose primary business is to sell electricity, or electricity and heat, to the public.
[5]Includes any natural gas used in the process of converting natural gas to liquid fuel that is not actually converted.
[6]Includes any natural gas that is converted into liquid fuel.
[7]Includes consumption of energy by electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public. Includes small power producers and exempt wholesale generators.
[8]Compressed natural gas used as vehicle fuel.
[9]Represents natural gas used in well, field, and lease operations, and in natural gas processing plant machinery.
[10]Balancing item. Natural gas lost as a result of converting flow data measured at varying temperatures and pressures to a standard temperature and pressure and the merger of different data reporting systems which vary in scope, format, definition, and respondent type. In addition, 2006 and 2007 values include net storage injections.
[11]Represents lower 48 onshore and offshore supplies.
[12]Compressed natural gas used as a vehicle fuel. Price includes estimated motor vehicle fuel taxes and estimated dispensing costs or charges.
[13]Weighted average prices. Weights used are the sectoral consumption values excluding lease, plant, and pipeline fuel.
- - = Not applicable.
Note: Totals may not equal sum of components due to independent rounding. Data for 2006 and 2007 are model results and may differ slightly from official EIA data reports.
Sources: 2006 supply values; and lease, plant, and pipeline fuel consumption: Energy Information Administration (EIA), *Natural Gas Annual 2006*, DOE/EIA-0131(2006) (Washington, DC, October 2007). 2007 supply values; and lease, plant, and pipeline fuel consumption; and wellhead price: EIA, *Natural Gas Monthly*, DOE/EIA-0130(2008/08) (Washington, DC, August 2008). Other 2006 and 2007 consumption based on: EIA, *Annual Energy Review 2007*, DOE/EIA-0384(2007) (Washington, DC, June 2008). 2006 wellhead price: Minerals Management Service and EIA, *Natural Gas Annual 2006*, DOE/EIA-0131(2006) (Washington, DC, October 2007). 2006 residential and commercial delivered prices: EIA, *Natural Gas Annual 2006*, DOE/EIA-0131(2006) (Washington, DC, October 2007). 2007 residential and commercial delivered prices: EIA, *Natural Gas Monthly*, DOE/EIA-0130(2008/08) (Washington, DC, August 2008). 2006 and 2007 electric power prices: EIA, *Electric Power Monthly*, DOE/EIA-0226, April 2007 and April 2008, Table 4.13.B. 2006 and 2007 industrial delivered prices are estimated based on: EIA, *Manufacturing Energy Consumption Survey 1994* and industrial and wellhead prices from the *Natural Gas Annual 2006*, DOE/EIA-0131(2006) (Washington, DC, October 2007) and the *Natural Gas Monthly*, DOE/EIA-0130(2008/08) (Washington, DC, August 2008). 2006 transportation sector delivered prices are based on: EIA, *Natural Gas Annual 2006*, DOE/EIA-0131(2006) (Washington, DC, October 2007) and estimated state taxes, federal taxes, and dispensing costs or charges. 2007 transportation sector delivered prices are model results. **Projections:** EIA, AEO2009 National Energy Modeling System run AEO2009.D120908A.

Table A14. Oil and Gas Supply

Production and Supply	Reference Case							Annual Growth 2007-2030 (percent)
	2006	2007	2010	2015	2020	2025	2030	
Crude Oil								
Lower 48 Average Wellhead Price[1]								
(2007 dollars per barrel)	**61.80**	**65.70**	**77.30**	**108.44**	**110.99**	**113.79**	**122.82**	**2.8%**
Production (million barrels per day)[2]								
United States Total	5.10	5.07	5.62	5.72	6.48	7.21	7.37	1.6%
Lower 48 Onshore	2.93	2.91	2.92	3.15	3.37	3.79	4.06	1.5%
Lower 48 Offshore	1.43	1.44	2.01	2.07	2.39	2.65	2.74	2.8%
Alaska	0.74	0.72	0.69	0.51	0.72	0.77	0.57	-1.0%
Lower 48 End of Year Reserves[2]								
(billion barrels)	**18.43**	**18.62**	**19.21**	**20.31**	**22.50**	**24.39**	**25.38**	**1.4%**
Natural Gas								
Lower 48 Average Wellhead Price[1]								
(2007 dollars per million Btu)								
Henry Hub Spot Price	6.91	6.96	6.66	6.90	7.43	8.08	9.25	1.2%
Average Lower 48 Wellhead Price[1]	6.48	6.22	5.88	6.10	6.56	7.13	8.17	1.2%
(2007 dollars per thousand cubic feet)								
Average Lower 48 Wellhead Price[1]	6.66	6.39	6.05	6.27	6.75	7.33	8.40	1.2%
Dry Production (trillion cubic feet)[3]								
United States Total	18.48	19.30	20.38	20.31	21.48	23.22	23.60	0.9%
Lower 48 Onshore	15.00	15.91	16.75	16.49	16.11	16.23	16.76	0.2%
Associated-Dissolved[4]	1.32	1.39	1.41	1.41	1.37	1.37	1.32	-0.2%
Non-Associated	13.69	14.51	15.34	15.08	14.74	14.86	15.44	0.3%
Conventional	5.06	5.36	4.70	4.13	3.36	2.65	2.18	-3.8%
Unconventional	8.62	9.15	10.64	10.95	11.38	12.20	13.26	1.6%
Gas Shale	1.07	1.17	2.31	2.64	2.97	3.45	4.15	5.7%
Coalbed Methane	1.84	1.84	1.79	1.76	1.78	1.90	2.01	0.4%
Tight Gas	5.71	6.15	6.54	6.55	6.62	6.85	7.10	0.6%
Lower 48 Offshore	3.05	2.97	3.26	3.49	4.23	5.04	4.88	2.2%
Associated-Dissolved[4]	0.63	0.62	0.72	0.89	1.00	1.10	1.16	2.8%
Non-Associated	2.42	2.35	2.55	2.59	3.23	3.94	3.72	2.0%
Alaska	0.42	0.42	0.37	0.33	1.14	1.96	1.96	6.9%
Lower 48 End of Year Dry Reserves[3]								
(trillion cubic feet)	**200.84**	**225.18**	**230.11**	**218.51**	**213.14**	**211.99**	**211.98**	**-0.3%**
Supplemental Gas Supplies (trillion cubic feet)[5]	**0.07**	**0.06**	**0.06**	**0.06**	**0.06**	**0.06**	**0.06**	**0.2%**
Total Lower 48 Wells Drilled (thousands)	**49.47**	**53.51**	**45.17**	**45.37**	**48.20**	**49.14**	**53.76**	**0.0%**

[1]Represents lower 48 onshore and offshore supplies.
[2]Includes lease condensate.
[3]Marketed production (wet) minus extraction losses.
[4]Gas which occurs in crude oil reservoirs either as free gas (associated) or as gas in solution with crude oil (dissolved).
[5]Synthetic natural gas, propane air, coke oven gas, refinery gas, biomass gas, air injected for Btu stabilization, and manufactured gas commingled and distributed with natural gas.

Note: Totals may not equal sum of components due to independent rounding. Data for 2006 and 2007 are model results and may differ slightly from official EIA data reports.

Sources: 2006 and 2007 crude oil lower 48 average wellhead price: Energy Information Administration (EIA), *Petroleum Marketing Annual 2007*, DOE/EIA-0487(2007) (Washington, DC, August 2008). 2006 and 2007 lower 48 onshore, lower 48 offshore, and Alaska crude oil production: EIA, *Petroleum Supply Annual 2007,* DOE/EIA-0340(2007)/1 (Washington, DC, July 2008). 2006 U.S. crude oil and natural gas reserves: EIA, *U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves*, DOE/EIA-0216(2006) (Washington, DC, December 2007). 2006 Alaska and total natural gas production, and supplemental gas supplies: EIA, *Natural Gas Annual 2006*, DOE/EIA-0131(2006) (Washington, DC, October 2007). 2006 natural gas lower 48 average wellhead price: Minerals Management Service and EIA, *Natural Gas Annual 2006*, DOE/EIA-0131(2006) (Washington, DC, October 2007). 2007 natural gas lower 48 average wellhead price, Alaska and total natural gas production, and supplemental gas supplies: EIA, *Natural Gas Monthly*, DOE/EIA-0130(2008/08) (Washington, DC, August 2008). Other 2006 and 2007 values: EIA, Office of Integrated Analysis and Forecasting. **Projections:** EIA, AEO2009 National Energy Modeling System run AEO2009.D120908A.

Table A15. Coal Supply, Disposition, and Prices
(Million Short Tons per Year, Unless Otherwise Noted)

Supply, Disposition, and Prices	Reference Case							Annual Growth 2007-2030 (percent)
	2006	2007	2010	2015	2020	2025	2030	
Production[1]								
Appalachia	392	378	383	343	333	339	353	-0.3%
Interior	151	147	163	192	206	220	252	2.4%
West	619	621	632	671	671	690	735	0.7%
East of the Mississippi	491	478	500	476	478	491	529	0.4%
West of the Mississippi	672	668	677	730	732	757	812	0.8%
Total	**1163**	**1147**	**1177**	**1206**	**1210**	**1248**	**1341**	**0.7%**
Waste Coal Supplied[2]	**14**	**14**	**11**	**13**	**12**	**12**	**13**	**-0.4%**
Net Imports								
Imports[3]	34	34	34	38	48	45	53	1.9%
Exports	50	59	82	65	53	53	44	-1.3%
Total	**-15**	**-25**	**-48**	**-28**	**-5**	**-8**	**10**	**- -**
Total Supply[4]	**1162**	**1136**	**1140**	**1192**	**1217**	**1252**	**1363**	**0.8%**
Consumption by Sector								
Residential and Commercial	3	4	3	3	3	3	3	-0.4%
Coke Plants	23	23	21	20	19	18	18	-1.0%
Other Industrial[5]	59	57	60	56	56	56	57	-0.0%
Coal-to-Liquids Heat and Power	0	0	0	9	16	26	38	- -
Coal to Liquids Production	0	0	0	8	14	22	32	- -
Electric Power[6]	1027	1046	1056	1096	1110	1126	1215	0.7%
Total	**1112**	**1129**	**1140**	**1192**	**1218**	**1252**	**1363**	**0.8%**
Discrepancy and Stock Change[7]	**50**	**7**	**0**	**-0**	**-0**	**-0**	**-0**	**- -**
Average Minemouth Price[8]								
(2007 dollars per short ton)	25.29	25.82	29.45	28.71	27.90	28.45	29.10	0.5%
(2007 dollars per million Btu)	1.25	1.27	1.44	1.42	1.39	1.42	1.46	0.6%
Delivered Prices (2007 dollars per short ton)[9]								
Coke Plants	95.37	94.97	114.53	115.38	115.37	119.22	115.57	0.9%
Other Industrial[5]	53.06	54.42	54.81	55.54	54.65	55.51	57.22	0.2%
Coal to Liquids	- -	- -	- -	17.14	17.89	19.89	20.96	- -
Electric Power								
(2007 dollars per short ton)	34.86	35.45	37.71	38.47	38.04	38.83	40.61	0.6%
(2007 dollars per million Btu)	1.74	1.78	1.89	1.94	1.92	1.96	2.04	0.6%
Average	**37.11**	**37.60**	**40.03**	**40.30**	**39.50**	**40.03**	**41.30**	**0.4%**
Exports[10]	72.84	70.25	83.77	88.70	89.48	89.86	80.02	0.6%

Table A15. Coal Supply, Disposition, and Prices (Continued)
(Million Short Tons per Year, Unless Otherwise Noted)

Supply, Disposition, and Prices	Reference Case							Annual Growth 2007-2030 (percent)
	2006	2007	2010	2015	2020	2025	2030	
Average Minemouth Price[8]								
(nominal dollars per short ton)	24.63	25.82	31.02	33.22	36.04	39.26	42.20	2.2%
(nominal dollars per million Btu)	1.21	1.27	1.52	1.65	1.80	1.96	2.11	2.2%
Delivered Prices (nominal dollars per short ton)[9]								
Coke Plants	92.87	94.97	120.62	133.51	149.04	164.48	167.56	2.5%
Other Industrial[5]	51.67	54.42	57.73	64.27	70.59	76.59	82.96	1.9%
Coal to Liquids	0.00	0.00	0.00	19.83	23.11	27.45	30.39	- -
Electric Power								
(nominal dollars per short ton)	33.95	35.45	39.72	44.51	49.14	53.57	58.88	2.2%
(nominal dollars per million Btu)	1.69	1.78	1.99	2.25	2.48	2.70	2.95	2.2%
Average	**36.14**	**37.60**	**42.16**	**46.63**	**51.03**	**55.22**	**59.88**	**2.0%**
Exports[10]	70.93	70.25	88.23	102.64	115.59	123.97	116.02	2.2%

[1]Includes anthracite, bituminous coal, subbituminous coal, and lignite.
[2]Includes waste coal consumed by the electric power and industrial sectors. Waste coal supplied is counted as a supply-side item to balance the same amount of waste coal included in the consumption data.
[3]Excludes imports to Puerto Rico and the U.S. Virgin Islands.
[4]Production plus waste coal supplied plus net imports.
[5]Includes consumption for combined heat and power plants, except those plants whose primary business is to sell electricity, or electricity and heat, to the public. Excludes all coal use in the coal-to-liquids process.
[6]Includes all electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public.
[7]Balancing item: the sum of production, net imports, and waste coal supplied minus total consumption.
[8]Includes reported prices for both open market and captive mines.
[9]Prices weighted by consumption; weighted average excludes residential and commercial prices, and export free-alongside-ship (f.a.s.) prices.
[10]F.a.s. price at U.S. port of exit.
- - = Not applicable.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Data for 2006 and 2007 are model results and may differ slightly from official EIA data reports.
Sources: 2006 and 2007 data based on: Energy Information Administration (EIA), *Annual Coal Report 2007*, DOE/EIA-0584(2007) (Washington, DC, September 2008); EIA, *Quarterly Coal Report, October-December 2007*, DOE/EIA-0121(2007/4Q) (Washington, DC, March 2008); and EIA, AEO2009 National Energy Modeling System run AEO2009.D120908A. **Projections:** EIA, AEO2009 National Energy Modeling System run AEO2009.D120908A.

Table A16. Renewable Energy Generating Capacity and Generation
(Gigawatts, Unless Otherwise Noted)

Capacity and Generation	Reference Case							Annual Growth 2007-2030 (percent)
	2006	2007	2010	2015	2020	2025	2030	
Electric Power Sector[1]								
Net Summer Capacity								
Conventional Hydropower	76.72	76.72	76.73	76.89	77.02	77.31	77.58	0.0%
Geothermal[2]	2.29	2.36	2.53	2.60	2.66	2.73	3.00	1.1%
Municipal Waste[3]	3.39	3.43	4.04	4.08	4.12	4.14	4.15	0.8%
Wood and Other Biomass[4,5]	2.01	2.18	2.20	2.20	4.22	5.20	8.86	6.3%
Solar Thermal	0.40	0.53	0.54	0.79	0.81	0.84	0.86	2.1%
Solar Photovoltaic[6]	0.03	0.04	0.06	0.13	0.21	0.29	0.38	10.4%
Wind	11.29	16.19	29.46	30.68	33.07	39.00	43.80	4.4%
Offshore Wind	0.00	0.00	0.00	0.20	0.20	0.20	0.20	- -
Total	**96.13**	**101.46**	**115.57**	**117.58**	**122.32**	**129.71**	**138.83**	**1.4%**
Generation (billion kilowatthours)								
Conventional Hydropower	286.11	245.86	268.05	295.33	296.29	297.94	298.97	0.9%
Geothermal[2]	14.57	14.84	17.78	18.62	19.11	19.63	21.80	1.7%
Biogenic Municipal Waste[7]	13.71	14.42	19.30	19.61	19.95	20.11	20.17	1.5%
Wood and Other Biomass[5]	10.33	10.38	28.07	56.22	117.82	133.50	140.44	12.0%
Dedicated Plants	8.42	8.41	12.85	13.11	28.74	36.19	62.27	9.1%
Cofiring	1.91	1.97	15.22	43.11	89.08	97.30	78.17	17.4%
Solar Thermal	0.49	0.60	0.99	1.81	1.88	1.95	2.02	5.5%
Solar Photovoltaic[6]	0.01	0.01	0.14	0.30	0.49	0.72	0.94	21.3%
Wind	26.59	32.14	80.50	84.48	92.45	112.13	129.38	6.2%
Offshore Wind	0.00	0.00	0.00	0.75	0.75	0.75	0.75	- -
Total	**351.82**	**318.25**	**414.82**	**477.12**	**548.75**	**586.72**	**614.47**	**2.9%**
End-Use Generators[8]								
Net Summer Capacity								
Conventional Hydropower[9]	0.70	0.70	0.70	0.70	0.70	0.70	0.70	0.0%
Geothermal	0.00	0.00	0.00	0.00	0.00	0.00	0.00	- -
Municipal Waste[10]	0.33	0.34	0.34	0.34	0.34	0.34	0.34	0.0%
Biomass	4.64	4.64	4.65	5.44	7.28	11.03	13.23	4.7%
Solar Photovoltaic[6]	0.28	0.43	1.73	7.05	9.72	10.14	11.78	15.5%
Wind	0.04	0.04	0.04	0.04	0.09	0.17	0.31	9.2%
Total	**5.99**	**6.15**	**7.45**	**13.57**	**18.12**	**22.37**	**26.35**	**6.5%**
Generation (billion kilowatthours)								
Conventional Hydropower[9]	2.99	2.45	2.45	2.45	2.45	2.45	2.45	0.0%
Geothermal	0.00	0.00	0.00	0.00	0.00	0.00	0.00	- -
Municipal Waste[10]	1.98	2.01	2.75	2.75	2.75	2.75	2.75	1.4%
Biomass	28.32	28.13	28.20	33.41	47.17	75.54	90.81	5.2%
Solar Photovoltaic[6]	0.44	0.68	2.78	11.55	16.02	16.69	19.49	15.7%
Wind	0.06	0.06	0.06	0.06	0.12	0.25	0.45	9.5%
Total	**33.78**	**33.33**	**36.24**	**50.23**	**68.51**	**97.69**	**115.95**	**5.6%**

Table A16. Renewable Energy Generating Capacity and Generation (Continued)
(Gigawatts, Unless Otherwise Noted)

Capacity and Generation	Reference Case							Annual Growth 2007-2030 (percent)
	2006	2007	2010	2015	2020	2025	2030	
Total, All Sectors								
Net Summer Capacity								
Conventional Hydropower	77.42	77.42	77.43	77.59	77.72	78.01	78.28	0.0%
Geothermal	2.29	2.36	2.53	2.60	2.66	2.73	3.00	1.1%
Municipal Waste	3.72	3.77	4.38	4.42	4.46	4.48	4.49	0.8%
Wood and Other Biomass[4,5]	6.65	6.82	6.85	7.64	11.50	16.23	22.08	5.2%
Solar[6]	0.71	1.00	2.33	7.97	10.74	11.27	13.02	11.8%
Wind	11.33	16.23	29.50	30.92	33.35	39.37	44.31	4.5%
Total	**102.12**	**107.60**	**123.02**	**131.15**	**140.44**	**152.08**	**165.18**	**1.9%**
Generation (billion kilowatthours)								
Conventional Hydropower	289.11	248.31	270.50	297.78	298.75	300.39	301.42	0.8%
Geothermal	14.57	14.84	17.78	18.62	19.11	19.63	21.80	1.7%
Municipal Waste	15.69	16.43	22.05	22.37	22.70	22.86	22.93	1.5%
Wood and Other Biomass[5]	38.65	38.51	56.26	89.63	164.99	209.04	231.25	8.1%
Solar[6]	0.95	1.29	3.91	13.66	18.39	19.36	22.45	13.2%
Wind	26.64	32.20	80.55	85.29	93.32	113.12	130.57	6.3%
Total	**385.61**	**351.58**	**451.06**	**527.36**	**617.26**	**684.41**	**730.42**	**3.2%**

[1]Includes electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public.
[2]Includes hydrothermal resources only (hot water and steam).
[3]Includes municipal waste, landfill gas, and municipal sewage sludge. Incremental growth is assumed to be for landfill gas facilities. All municipal waste is included, although a portion of the municipal waste stream contains petroleum-derived plastics and other non-renewable sources.
[4]Facilities co-firing biomass and coal are classified as coal.
[5]Includes projections for energy crops after 2012.
[6]Does not include off-grid photovoltaics (PV). Based on annual PV shipments from 1989 through 2006, EIA estimates that as much as 210 megawatts of remote electricity generation PV applications (i.e., off-grid power systems) were in service in 2006, plus an additional 526 megawatts in communications, transportation, and assorted other non-grid-connected, specialized applications. See Energy Information Administration, *Annual Energy Review 2007*, DOE/EIA-0384(2007) (Washington, DC, June 2008), Table 10.8 (annual PV shipments, 1989-2006). The approach used to develop the estimate, based on shipment data, provides an upper estimate of the size of the PV stock, including both grid-based and off-grid PV. It will overestimate the size of the stock, because shipments include a substantial number of units that are exported, and each year some of the PV units installed earlier will be retired from service or abandoned.
[7]Includes biogenic municipal waste, landfill gas, and municipal sewage sludge. Incremental growth is assumed to be for landfill gas facilities. Only biogenic municipal waste is included. The Energy Information Administration estimates that in 2007 approximately 6 billion kilowatthours of electricity were generated from a municipal waste stream containing petroleum-derived plastics and other non-renewable sources. See Energy Information Administration, *Methodology for Allocating Municipal Solid Waste to Biogenic and Non-Biogenic Energy* (Washington, DC, May 2007).
[8]Includes combined heat and power plants and electricity-only plants in the commercial and industrial sectors; and small on-site generating systems in the residential, commercial, and industrial sectors used primarily for own-use generation, but which may also sell some power to the grid.
[9]Represents own-use industrial hydroelectric power.
[10]Includes municipal waste, landfill gas, and municipal sewage sludge. All municipal waste is included, although a portion of the municipal waste stream contains petroleum-derived plastics and other non-renewable sources.
- - = Not applicable.
Note: Totals may not equal sum of components due to independent rounding. Data for 2006 and 2007 are model results and may differ slightly from official EIA data reports.
Sources: 2006 and 2007 capacity: Energy Information Administration (EIA), Form EIA-860, "Annual Electric Generator Report" (preliminary). 2006 and 2007 generation: EIA, *Annual Energy Review 2007*, DOE/EIA-0384(2007) (Washington, DC, June 2008). **Projections:** EIA, AEO2009 National Energy Modeling System run AEO2009.D120908A.

Table A17. Renewable Energy, Consumption by Sector and Source[1]
(Quadrillion Btu per Year)

Sector and Source	Reference Case							Annual Growth 2007-2030 (percent)
	2006	2007	2010	2015	2020	2025	2030	
Marketed Renewable Energy[2]								
Residential (wood)	**0.39**	**0.43**	**0.43**	**0.46**	**0.48**	**0.49**	**0.50**	**0.7%**
Commercial (biomass)	**0.12**	**0.12**	**0.12**	**0.12**	**0.12**	**0.12**	**0.12**	**0.0%**
Industrial[3]	**2.00**	**2.04**	**2.23**	**2.51**	**2.87**	**3.41**	**3.62**	**2.5%**
Conventional Hydroelectric	0.03	0.02	0.02	0.02	0.02	0.02	0.02	0.0%
Municipal Waste[4]	0.15	0.16	0.12	0.12	0.12	0.12	0.12	-1.2%
Biomass	1.52	1.46	1.34	1.41	1.49	1.64	1.81	0.9%
Biofuels Heat and Coproducts	0.30	0.40	0.75	0.95	1.23	1.62	1.66	6.4%
Transportation	**0.50**	**0.64**	**1.23**	**1.68**	**2.06**	**2.93**	**3.43**	**7.6%**
Ethanol used in E85[5]	0.00	0.00	0.00	0.23	0.56	1.12	1.44	37.1%
Ethanol used in Gasoline Blending	0.47	0.58	1.08	1.15	1.10	1.04	1.04	2.6%
Biodiesel used in Distillate Blending	0.03	0.06	0.12	0.20	0.20	0.24	0.25	6.2%
Liquids from Biomass	0.00	0.00	0.00	0.02	0.15	0.47	0.65	- -
Green Liquids	0.00	0.00	0.02	0.08	0.06	0.06	0.06	- -
Electric Power[6]	**3.76**	**3.45**	**4.42**	**5.07**	**5.79**	**6.17**	**6.43**	**2.7%**
Conventional Hydroelectric	2.84	2.44	2.65	2.92	2.92	2.94	2.95	0.8%
Geothermal	0.31	0.31	0.38	0.41	0.43	0.44	0.51	2.1%
Biogenic Municipal Waste[7]	0.15	0.17	0.23	0.24	0.24	0.24	0.24	1.7%
Biomass	0.19	0.21	0.35	0.64	1.25	1.40	1.41	8.6%
Dedicated Plants	0.15	0.16	0.15	0.13	0.28	0.35	0.61	5.9%
Cofiring	0.04	0.05	0.21	0.51	0.98	1.05	0.80	12.9%
Solar Thermal	0.00	0.01	0.01	0.02	0.02	0.02	0.02	5.5%
Solar Photovoltaic	0.00	0.00	0.00	0.00	0.00	0.01	0.01	21.3%
Wind	0.26	0.32	0.80	0.84	0.92	1.12	1.29	6.3%
Total Marketed Renewable Energy	**6.77**	**6.69**	**8.43**	**9.84**	**11.32**	**13.12**	**14.10**	**3.3%**
Sources of Ethanol								
From Corn	0.41	0.55	1.08	1.34	1.42	1.42	1.41	4.2%
From Cellulose	0.00	0.00	0.00	0.03	0.18	0.42	0.43	- -
Imports	0.06	0.03	-0.00	0.01	0.06	0.32	0.63	14.5%
Total	**0.47**	**0.58**	**1.08**	**1.39**	**1.66**	**2.16**	**2.47**	**6.5%**

Table A17. Renewable Energy, Consumption by Sector and Source[1] (Continued)
(Quadrillion Btu per Year)

Sector and Source	Reference Case							Annual Growth 2007-2030 (percent)
	2006	2007	2010	2015	2020	2025	2030	
Nonmarketed Renewable Energy[8] Selected Consumption								
Residential	**0.01**	**0.01**	**0.01**	**0.05**	**0.07**	**0.07**	**0.08**	**11.5%**
Solar Hot Water Heating	0.00	0.00	0.00	0.00	0.00	0.01	0.01	2.6%
Geothermal Heat Pumps	0.00	0.00	0.00	0.01	0.01	0.02	0.02	9.1%
Solar Photovoltaic	0.00	0.00	0.01	0.03	0.05	0.05	0.05	25.2%
Wind	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.0%
Commercial	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**	**0.04**	**0.04**	**2.0%**
Solar Thermal	0.02	0.02	0.03	0.03	0.03	0.03	0.03	0.5%
Solar Photovoltaic	0.00	0.00	0.00	0.01	0.01	0.01	0.01	8.4%
Wind	0.00	0.00	0.00	0.00	0.00	0.00	0.00	13.3%

[1]Actual heat rates used to determine fuel consumption for all renewable fuels except hydropower, solar, and wind. Consumption at hydroelectric, solar, and wind facilities determined by using the fossil fuel equivalent of 10,022 Btu per kilowatthour.
[2]Includes nonelectric renewable energy groups for which the energy source is bought and sold in the marketplace, although all transactions may not necessarily be marketed, and marketed renewable energy inputs for electricity entering the marketplace on the electric power grid. Excludes electricity imports; see Table A2.
[3]Includes all electricity production by industrial and other combined heat and power for the grid and for own use.
[4]Includes municipal waste, landfill gas, and municipal sewage sludge. All municipal waste is included, although a portion of the municipal waste stream contains petroleum-derived plastics and other non-renewable sources.
[5]Excludes motor gasoline component of E85.
[6]Includes consumption of energy by electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public. Includes small power producers and exempt wholesale generators.
[7]Includes biogenic municipal waste, landfill gas, and municipal sewage sludge. Incremental growth is assumed to be for landfill gas facilities. Only biogenic municipal waste is included. The Energy Information Administration estimates that in 2007 approximately 0.3 quadrillion Btus were consumed from a municipal waste stream containing petroleum-derived plastics and other non-renewable sources. See Energy Information Administration, *Methodology for Allocating Municipal Solid Waste to Biogenic and Non-Biogenic Energy* (Washington, DC, May 2007).
[8]Includes selected renewable energy consumption data for which the energy is not bought or sold, either directly or indirectly as an input to marketed energy. The Energy Information Administration does not estimate or project total consumption of nonmarketed renewable energy.
- - = Not applicable.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Data for 2006 and 2007 are model results and may differ slightly from official EIA data reports.
Sources: 2006 and 2007 ethanol: Energy Information Administration (EIA), *Annual Energy Review 2007*, DOE/EIA-0384(2007) (Washington, DC, June 2008). 2006 and 2007 electric power sector: EIA, Form EIA-860, "Annual Electric Generator Report" (preliminary). Other 2006 and 2007 values: EIA, Office of Integrated Analysis and Forecasting. **Projections:** EIA, AEO2009 National Energy Modeling System run AEO2009.D120908A.

Table A18. Carbon Dioxide Emissions by Sector and Source
(Million Metric Tons, Unless Otherwise Noted)

Sector and Source	Reference Case							Annual Growth 2007-2030 (percent)
	2006	2007	2010	2015	2020	2025	2030	
Residential								
Petroleum	89	88	89	82	80	77	75	-0.7%
Natural Gas	237	257	261	266	270	272	269	0.2%
Coal	1	1	1	1	1	1	1	1.1%
Electricity[1]	871	904	886	876	899	930	987	0.4%
Total	**1198**	**1250**	**1237**	**1224**	**1250**	**1280**	**1332**	**0.3%**
Commercial								
Petroleum	45	45	41	42	42	42	42	-0.3%
Natural Gas	154	163	167	172	177	183	188	0.6%
Coal	6	7	6	6	6	6	6	-0.4%
Electricity[1]	837	872	878	926	979	1026	1096	1.0%
Total	**1043**	**1088**	**1092**	**1147**	**1205**	**1257**	**1332**	**0.9%**
Industrial[2]								
Petroleum	420	406	377	378	369	367	375	-0.4%
Natural Gas[3]	395	405	414	424	421	433	440	0.4%
Coal	186	175	174	178	183	198	215	0.9%
Electricity[1]	652	653	617	631	612	610	638	-0.1%
Total	**1653**	**1640**	**1582**	**1610**	**1585**	**1607**	**1667**	**0.1%**
Transportation								
Petroleum[4]	1975	1974	1851	1880	1896	1931	2032	0.1%
Natural Gas[5]	33	35	36	37	40	43	43	0.8%
Electricity[1]	4	4	4	5	6	7	9	3.3%
Total	**2013**	**2014**	**1891**	**1922**	**1942**	**1982**	**2084**	**0.1%**
Electric Power[6]								
Petroleum	66	66	38	39	40	40	41	-2.0%
Natural Gas	339	376	341	329	357	403	378	0.0%
Coal	1947	1980	1995	2058	2089	2118	2299	0.7%
Other[7]	12	12	12	12	12	12	12	0.1%
Total	**2364**	**2433**	**2385**	**2437**	**2497**	**2572**	**2729**	**0.5%**
Total by Fuel								
Petroleum[3]	2596	2580	2396	2421	2427	2458	2564	-0.0%
Natural Gas	1159	1237	1218	1228	1265	1333	1318	0.3%
Coal	2140	2162	2176	2242	2278	2322	2521	0.7%
Other[7]	12	12	12	12	12	12	12	0.1%
Total	**5907**	**5991**	**5801**	**5904**	**5982**	**6125**	**6414**	**0.3%**
Carbon Dioxide Emissions (tons per person)	**19.7**	**19.8**	**18.6**	**18.1**	**17.5**	**17.1**	**17.1**	**-0.6%**

[1]Emissions from the electric power sector are distributed to the end-use sectors.
[2]Fuel consumption includes energy for combined heat and power plants, except those plants whose primary business is to sell electricity, or electricity and heat, to the public.
[3]Includes lease and plant fuel.
[4]This includes carbon dioxide from international bunker fuels, both civilian and military, which are excluded from the accounting of carbon dioxide emissions under the United Nations convention. From 1990 through 2007, international bunker fuels accounted for 84 to 131 million metric tons annually.
[5]Includes pipeline fuel natural gas and compressed natural gas used as vehicle fuel.
[6]Includes electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public.
[7]Includes emissions from geothermal power and nonbiogenic emissions from municipal waste.
Note: Totals may not equal sum of components due to independent rounding. Data for 2006 and 2007 are model results and may differ slightly from official EIA data reports.
Sources: 2006 and 2007 emissions and emission factors: Energy Information Administration (EIA), *Emissions of Greenhouse Gases in the United States 2007,* DOE/EIA-0573(2007) (Washington, DC, December 2008). **Projections:** EIA, AEO2009 National Energy Modeling System run AEO2009.D120908A.

Table A19. Energy-Related Carbon Dioxide Emissions by End Use
(Million Metric Tons)

Sector and Source	Reference Case							Annual Growth 2007-2030 (percent)
	2006	2007	2010	2015	2020	2025	2030	
Residential								
Space Heating	262.44	292.79	291.82	290.68	291.30	289.27	286.17	-0.1%
Space Cooling	157.96	168.73	158.68	162.58	169.72	177.92	190.05	0.5%
Water Heating	165.56	165.97	161.74	161.39	166.79	168.00	165.41	-0.0%
Refrigeration	73.73	73.53	68.88	67.07	67.93	69.20	73.42	-0.0%
Cooking	33.18	33.74	34.00	35.62	37.37	38.57	40.30	0.8%
Clothes Dryers	54.20	54.72	53.38	53.66	53.99	54.92	58.11	0.3%
Freezers	15.59	15.54	14.64	14.43	14.66	14.91	15.66	0.0%
Lighting	140.12	139.35	132.07	106.42	97.54	91.23	90.61	-1.9%
Clothes Washers[1]	6.70	6.65	5.99	5.39	4.74	4.65	4.93	-1.3%
Dishwashers[1]	18.04	18.13	17.32	17.27	17.81	18.61	20.07	0.4%
Color Televisions and Set-Top Boxes	64.02	68.64	74.30	74.34	77.16	85.02	97.19	1.5%
Personal Computers and Related Equipment	27.08	29.19	33.47	33.48	34.62	36.41	39.39	1.3%
Furnace Fans and Boiler Circulation Pumps	21.51	24.35	24.21	25.57	26.76	27.36	28.42	0.7%
Other Uses	157.49	165.08	166.42	176.29	189.62	203.60	222.05	1.3%
Discrepancy[2]	0.57	-6.59	0.00	-0.00	0.00	-0.00	0.00	- -
Total Residential	**1198.19**	**1249.82**	**1236.92**	**1224.19**	**1250.00**	**1279.66**	**1331.78**	**0.3%**
Commercial								
Space Heating[3]	112.77	121.65	122.71	124.04	125.18	124.75	123.26	0.1%
Space Cooling[3]	102.77	107.73	102.62	104.73	106.83	109.55	115.01	0.3%
Water Heating[3]	43.27	43.32	42.19	44.11	45.75	47.13	47.99	0.4%
Ventilation	90.03	93.93	97.80	106.84	113.27	117.77	123.43	1.2%
Cooking	13.01	13.26	13.67	14.19	14.70	15.23	15.65	0.7%
Lighting	203.06	204.00	195.55	198.02	202.04	204.53	210.90	0.1%
Refrigeration	74.86	76.78	73.02	68.19	66.80	66.88	69.59	-0.4%
Office Equipment (PC)	40.50	46.08	46.77	48.70	51.55	55.00	58.63	1.1%
Office Equipment (non-PC)	36.39	40.08	47.47	57.87	66.68	70.90	75.05	2.8%
Other Uses[4]	326.54	340.75	350.49	380.06	411.93	445.25	492.05	1.6%
Total Commercial	**1043.20**	**1087.58**	**1092.29**	**1146.73**	**1204.72**	**1256.98**	**1331.56**	**0.9%**
Industrial								
Manufacturing								
Refining	250.67	251.30	258.31	279.74	291.74	304.37	327.84	1.2%
Food Products	95.58	98.58	103.37	103.68	107.57	112.37	119.68	0.8%
Paper Products	97.37	93.56	87.16	86.97	85.70	85.71	88.86	-0.2%
Bulk Chemicals	313.24	313.68	279.94	272.61	247.77	236.18	221.91	-1.5%
Glass	17.09	17.18	16.88	20.35	21.25	21.53	21.37	1.0%
Cement Manufacturing	42.36	41.73	32.97	39.81	40.16	40.76	40.58	-0.1%
Iron and Steel	141.17	137.15	117.98	122.20	113.43	113.69	116.17	-0.7%
Aluminum	46.43	44.83	42.50	40.07	36.66	34.18	32.23	-1.4%
Fabricated Metal Products	42.57	42.78	36.15	40.05	36.82	36.73	36.51	-0.7%
Machinery	21.55	21.37	18.40	21.20	20.66	21.09	21.97	0.1%
Computers and Electronics	28.11	29.59	24.66	28.68	32.37	38.09	53.58	2.6%
Transportation Equipment	43.21	42.05	39.29	41.73	40.09	41.11	41.69	-0.0%
Electrical Equipment	16.99	17.30	13.91	16.23	16.85	18.65	22.37	1.1%
Wood Products	18.37	17.78	17.80	22.20	20.10	19.42	19.59	0.4%
Plastics	40.88	40.78	37.60	38.42	38.84	39.57	43.38	0.3%
Balance of Manufacturing	174.80	170.54	150.34	153.92	154.38	154.34	160.37	-0.3%
Total Manufacturing	1390.40	1380.18	1277.28	1327.87	1304.41	1317.79	1368.09	-0.0%
Nonmanufacturing								
Agriculture	82.05	96.37	86.33	87.23	85.70	86.14	88.95	-0.3%
Mining	81.75	76.75	59.38	76.15	72.43	72.49	76.07	-0.0%
Construction	83.77	80.59	77.18	77.98	76.44	78.28	79.62	-0.1%
Total Nonmanufacturing	247.57	253.71	222.89	241.36	234.56	236.91	244.63	-0.2%
Discrepancy[2]	14.59	5.93	81.53	40.91	46.14	52.42	54.56	10.1%
Total Industrial	**1652.56**	**1639.83**	**1581.70**	**1610.14**	**1585.11**	**1607.12**	**1667.28**	**0.1%**

Table A19. Energy-Related Carbon Dioxide Emissions by End Use (Continued)
(Million Metric Tons)

Sector and Source	Reference Case							Annual Growth 2007-2030 (percent)
	2006	2007	2010	2015	2020	2025	2030	
Transportation								
Light-Duty Vehicles	1146.29	1137.83	1076.13	1030.99	1007.98	988.58	1002.45	-0.5%
Commercial Light Trucks[5]	43.12	43.08	37.81	40.32	39.85	40.72	44.04	0.1%
Bus Transportation	19.95	19.57	19.11	18.99	19.08	19.42	20.06	0.1%
Freight Trucks	368.22	371.85	343.12	392.59	409.93	436.61	488.21	1.2%
Rail, Passenger	5.69	5.82	5.84	6.29	6.60	6.88	7.30	1.0%
Rail, Freight	42.89	43.01	40.74	44.59	46.39	48.30	52.19	0.8%
Shipping, Domestic	25.02	25.11	23.52	25.88	27.51	29.30	30.69	0.9%
Shipping, International	66.06	69.31	62.74	69.81	70.25	70.69	71.23	0.1%
Recreational Boats	17.26	17.48	16.86	17.28	17.63	18.07	18.55	0.3%
Air	192.25	192.03	173.66	185.56	203.42	225.45	250.83	1.2%
Military Use	49.63	50.27	52.93	51.51	52.83	54.13	55.40	0.4%
Lubricants	5.45	5.19	5.17	5.32	5.41	5.52	5.67	0.4%
Pipeline Fuel	0.03	0.03	0.03	0.03	0.04	0.04	0.04	0.5%
Discrepancy[2]	30.97	33.02	32.85	33.30	35.50	37.89	37.16	0.5%
Total Transportation	**2012.83**	**2013.59**	**1890.52**	**1922.48**	**1942.43**	**1981.59**	**2083.81**	**0.1%**

[1]Does not include water heating portion of load.
[2]Represents differences between total emissions by end-use and total emissions by fuel as reported in Table A18. Emissions by fuel may reflect benchmarking and other modeling adjustments to energy use and the associated emissions that are not assigned to specific end uses.
[3]Includes emissions related to fuel consumption for district services.
[4]Includes miscellaneous uses, such as service station equipment, automated teller machines, telecommunications equipment, medical equipment, pumps, emergency generators, combined heat and power in commercial buildings, manufacturing performed in commercial buildings, and cooking (distillate), plus emissions from residual fuel oil, liquefied petroleum gases, coal, motor gasoline, and kerosene.
[5]Commercial trucks 8,500 to 10,000 pounds.
- - = Not applicable.
Note: Totals may not equal sum of components due to independent rounding. Data for 2006 and 2007 are model results and may differ slightly from official EIA data reports.
Sources: 2006 and 2007 emissions and emission factors: Energy Information Administration (EIA), *Emissions of Greenhouse Gases in the United States 2007,* DOE/EIA-0573(2007) (Washington, DC, December 2008). **Projections:** EIA, AEO2009 National Energy Modeling System run AEO2009.D120908A.

Table A20. Macroeconomic Indicators
(Billion 2000 Chain-Weighted Dollars, Unless Otherwise Noted)

Indicators	Reference Case 2006	2007	2010	2015	2020	2025	2030	Annual Growth 2007-2030 (percent)
Real Gross Domestic Product	**11295**	**11524**	**11779**	**13745**	**15524**	**17591**	**20114**	**2.5%**
Components of Real Gross Domestic Product								
Real Consumption	8029	8253	8435	9626	10876	12144	13439	2.1%
Real Investment	1912	1810	1581	2265	2565	3067	3756	3.2%
Real Government Spending	1971	2012	2065	2094	2194	2296	2427	0.8%
Real Exports	1315	1426	1585	2291	3061	4122	5820	6.3%
Real Imports	1931	1972	1899	2446	3007	3722	4717	3.9%
Energy Intensity (thousand Btu per 2000 dollar of GDP)								
Delivered Energy	6.45	6.42	6.09	5.39	4.86	4.44	4.04	-2.0%
Total Energy	8.86	8.84	8.48	7.48	6.79	6.20	5.65	-1.9%
Price Indices								
GDP Chain-type Price Index (2000=1.000)	1.167	1.198	1.262	1.386	1.548	1.653	1.737	1.6%
Consumer Price Index (1982-4=1.00)								
All-urban	2.02	2.07	2.20	2.49	2.83	3.08	3.31	2.1%
Energy Commodities and Services	1.97	2.08	2.18	2.75	3.16	3.48	3.87	2.7%
Wholesale Price Index (1982=1.00)								
All Commodities	1.65	1.73	1.80	2.01	2.19	2.27	2.36	1.4%
Fuel and Power	1.67	1.77	1.91	2.37	2.74	3.04	3.45	2.9%
Metals and Metal Products	1.82	1.93	1.82	2.08	2.21	2.17	2.22	0.6%
Interest Rates (percent, nominal)								
Federal Funds Rate	4.96	5.02	1.30	5.43	5.20	5.17	4.04	- -
10-Year Treasury Note	4.79	4.63	3.67	5.74	5.86	5.64	4.67	- -
AA Utility Bond Rate	5.84	5.94	6.39	7.71	7.49	7.12	5.79	- -
Value of Shipments (billion 2000 dollars)								
Total Industrial	5763	5750	5240	6276	6753	7402	8451	1.7%
Nonmanufacturing	1503	1490	1277	1581	1603	1671	1780	0.8%
Manufacturing	4260	4261	3963	4694	5150	5732	6671	2.0%
Energy-Intensive	1218	1239	1238	1321	1374	1441	1525	0.9%
Non-energy Intensive	3042	3022	2725	3373	3776	4290	5145	2.3%
Population and Employment (millions)								
Population, with Armed Forces Overseas	299.6	302.4	311.4	326.7	342.6	358.9	375.1	0.9%
Population, aged 16 and over	234.5	237.2	245.2	257.4	270.4	283.9	297.6	1.0%
Population, over age 65	37.4	38.0	40.4	47.0	55.0	64.2	72.3	2.8%
Employment, Nonfarm	135.7	137.2	135.6	147.2	152.6	159.2	168.3	0.9%
Employment, Manufacturing	14.2	13.9	12.2	12.6	12.3	12.1	11.7	-0.7%
Key Labor Indicators								
Labor Force (millions)	151.4	153.1	155.9	163.2	168.4	174.0	181.5	0.7%
Nonfarm Labor Productivity (1992=1.00)	1.35	1.37	1.45	1.57	1.74	1.93	2.14	2.0%
Unemployment Rate (percent)	4.61	4.64	8.26	5.68	5.53	5.41	4.78	- -
Key Indicators for Energy Demand								
Real Disposable Personal Income	8407	8644	9017	10468	12035	13715	15450	2.6%
Housing Starts (millions)	1.93	1.44	1.18	2.00	1.77	1.74	1.74	0.8%
Commercial Floorspace (billion square feet)	75.8	77.3	81.2	86.1	92.3	97.5	103.3	1.3%
Unit Sales of Light-Duty Vehicles (millions)	16.50	16.09	14.18	17.07	17.41	18.86	20.99	1.2%

GDP = Gross domestic product.
Btu = British thermal unit.
- - = Not applicable.
Sources: 2006 and 2007: IHS Global Insight Industry and Employment models, November 2008. **Projections:** Energy Information Administration, AEO2009 National Energy Modeling System run AEO2009.D120908A.

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

Supply and Disposition	Reference Case							Annual Growth 2007-2030 (percent)
	2006	2007	2010	2015	2020	2025	2030	
Crude Oil Prices (2007 dollars per barrel)[1]								
Imported Low Sulfur Light Crude Oil	67.82	72.33	80.16	110.49	115.45	121.94	130.43	2.6%
Imported Crude Oil	60.70	63.83	77.56	108.52	112.05	115.33	124.60	3.0%
Crude Oil Prices (nominal dollars per barrel)[1]								
Imported Low Sulfur Light Crude Oil	66.04	72.33	84.42	127.84	149.14	168.24	189.10	4.3%
Imported Crude Oil	59.10	63.83	81.69	125.57	144.74	159.11	180.66	4.6%
Conventional Production (Conventional)[2]								
OPEC[3]								
Middle East	23.50	22.97	22.77	23.62	25.22	26.59	28.34	0.9%
North Africa	3.93	4.02	4.25	4.54	4.61	4.81	5.19	1.1%
West Africa	3.88	4.12	4.81	5.19	5.23	5.48	5.92	1.6%
South America	2.68	2.58	2.26	2.14	2.42	2.66	2.73	0.2%
Total OPEC	**33.99**	**33.68**	**34.09**	**35.49**	**37.48**	**39.53**	**42.18**	**1.0%**
Non-OPEC								
OECD								
United States (50 states)	7.86	8.11	8.81	8.96	9.71	10.38	10.44	1.1%
Canada	2.06	2.05	1.90	1.50	1.25	1.11	1.02	-3.0%
Mexico	3.71	3.50	2.87	2.53	2.24	2.29	2.45	-1.5%
OECD Europe[4]	5.48	5.23	4.27	3.61	3.18	3.01	2.94	-2.5%
Japan	0.13	0.13	0.14	0.15	0.16	0.17	0.18	1.3%
Australia and New Zealand	0.58	0.64	0.82	0.79	0.78	0.78	0.77	0.8%
Total OECD	**19.82**	**19.66**	**18.80**	**17.54**	**17.32**	**17.73**	**17.81**	**-0.4%**
Non-OECD								
Russia	9.68	9.88	9.50	9.73	10.24	10.28	10.50	0.3%
Other Europe and Eurasia[5]	2.63	2.88	3.58	4.15	4.50	4.60	4.86	2.3%
China	3.84	3.90	3.75	3.53	3.52	3.32	3.19	-0.9%
Other Asia[6]	3.88	3.75	3.88	3.73	3.85	3.85	3.68	-0.1%
Middle East	1.62	1.52	1.42	1.40	1.40	1.37	1.36	-0.5%
Africa	2.41	2.41	2.65	2.60	2.72	2.85	2.98	0.9%
Brazil	1.86	1.88	2.48	2.90	3.45	3.82	4.19	3.5%
Other Central and South America	1.83	1.79	1.70	1.51	1.56	1.76	2.05	0.6%
Total Non-OECD	**27.75**	**28.01**	**28.96**	**29.56**	**31.25**	**31.83**	**32.81**	**0.7%**
Total Conventional Production	**81.56**	**81.35**	**81.85**	**82.58**	**86.04**	**89.10**	**92.80**	**0.6%**
Unconventional Production[7]								
United States (50 states)	0.34	0.46	0.91	1.27	1.55	2.04	2.31	7.3%
Other North America	1.23	1.38	1.92	2.83	3.34	3.86	4.31	5.1%
OECD Europe[4]	0.09	0.11	0.13	0.15	0.19	0.23	0.27	4.1%
Middle East	0.09	0.09	0.01	0.12	0.17	0.21	0.22	3.7%
Africa.	0.17	0.23	0.27	0.42	0.50	0.61	0.72	5.2%
Central and South America	0.91	1.02	1.15	1.51	2.04	2.61	3.16	5.0%
Other	0.24	0.30	0.47	0.60	0.78	1.23	1.63	7.7%
Total Unconventional Production	**3.06**	**3.58**	**4.85**	**6.89**	**8.56**	**10.78**	**12.61**	**5.6%**
Total Production	**84.62**	**84.93**	**86.71**	**89.47**	**94.60**	**99.88**	**105.41**	**0.9%**

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

Supply and Disposition	Reference Case							Annual Growth 2007-2030 (percent)
	2006	2007	2010	2015	2020	2025	2030	
Consumption[8]								
OECD								
United States (50 states)	20.65	20.65	19.69	20.16	20.21	20.76	21.67	0.2%
United States Territories	0.38	0.39	0.44	0.49	0.53	0.57	0.62	2.0%
Canada	2.31	2.41	2.28	2.24	2.29	2.34	2.39	-0.0%
Mexico	2.06	2.10	2.06	2.13	2.28	2.46	2.67	1.0%
OECD Europe[3]	15.75	15.36	14.74	14.24	14.24	14.28	14.27	-0.3%
Japan	5.22	5.02	4.68	4.37	4.27	4.16	4.02	-1.0%
South Korea	2.29	2.34	2.31	2.46	2.58	2.71	2.81	0.8%
Australia and New Zealand	1.06	1.08	1.04	1.05	1.09	1.14	1.20	0.5%
Total OECD	**49.73**	**49.35**	**47.24**	**47.14**	**47.50**	**48.43**	**49.64**	**0.0%**
Non-OECD								
Russia	2.83	2.88	2.97	3.02	3.18	3.29	3.35	0.7%
Other Europe and Eurasia[5]	2.18	2.24	2.34	2.46	2.64	2.81	2.96	1.2%
China	7.22	7.63	8.50	9.34	11.29	13.16	15.08	3.0%
India	2.42	2.46	2.60	3.00	3.51	3.99	4.52	2.7%
Other Asia[6]	6.21	6.28	6.39	7.08	7.75	8.38	9.03	1.6%
Middle East	6.11	6.42	7.02	7.59	8.26	8.87	9.45	1.7%
Africa	3.08	3.22	3.49	3.65	3.90	3.99	4.02	1.0%
Brazil	2.27	2.37	2.55	2.63	2.84	3.06	3.32	1.5%
Other Central and South America	3.20	3.35	3.60	3.58	3.73	3.90	4.04	0.8%
Total Non-OECD	**35.54**	**36.85**	**39.46**	**42.34**	**47.10**	**51.45**	**55.77**	**1.8%**
Total Consumption	**85.26**	**86.20**	**86.70**	**89.47**	**94.60**	**99.88**	**105.41**	**0.9%**
OPEC Production[9]	34.67	34.38	34.75	36.35	38.51	40.76	43.63	1.0%
Non-OPEC Production[9]	49.94	50.55	51.96	53.13	56.09	59.11	61.78	0.9%
Net Eurasia Exports	9.15	9.52	10.24	11.30	12.37	12.60	13.25	1.5%
OPEC Market Share (percent)	41.0	40.5	40.1	40.6	40.7	40.8	41.4	- -

[1]Weighted average price delivered to U.S. refiners.
[2]Includes production of crude oil (including lease condensate), natural gas plant liquids, other hydrogen and hydrocarbons for refinery feedstocks, alcohol and other sources, and refinery gains.
[3]OPEC = Organization of Petroleum Exporting Countries - Algeria, Angola, Ecuador, Iran, Iraq, Kuwait, Libya, Nigeria, Qatar, Saudi Arabia, the United Arab Emirates, and Venezuela.
[4]OECD Europe = Organization for Economic Cooperation and Development - Austria, Belgium, Czech Republic, Denmark, Finland, France, Germany, Greece, Hungary, Iceland, Ireland, Italy, Luxembourg, the Netherlands, Norway, Poland, Portugal, Slovakia, Spain, Sweden, Switzerland, Turkey, and the United Kingdom.
[5]Other Europe and Eurasia = Albania, Armenia, Azerbaijan, Belarus, Bosnia and Herzegovina, Bulgaria, Croatia, Estonia, Georgia, Kazakhstan, Kyrgyzstan, Latvia, Lithuania, Macedonia, Malta, Moldova, Montenegro, Romania, Serbia, Slovenia, Tajikistan, Turkmenistan, Ukraine, and Uzbekistan.
[6]Other Asia = Afghanistan, Bangladesh, Bhutan, Brunei, Cambodia (Kampuchea), Fiji, French Polynesia, Guam, Hong Kong, Indonesia, Kiribati, Laos, Malaysia, Macau, Maldives, Mongolia, Myanmar (Burma), Nauru, Nepal, New Caledonia, Niue, North Korea, Pakistan, Papua New Guinea, Philippines, Samoa, Singapore, Solomon Islands, Sri Lanka, Taiwan, Thailand, Tonga, Vanuatu, and Vietnam.
[7]Includes liquids produced from energy crops, natural gas, coal, extra-heavy oil, oil sands, and shale. Includes both OPEC and non-OPEC producers in the regional breakdown.
[8]Includes both OPEC and non-OPEC consumers in the regional breakdown.
[9]Includes both conventional and unconventional liquids production.
- - = Not applicable.
Note: Totals may not equal sum of components due to independent rounding. Data for 2006 and 2007 are model results and may differ slightly from official EIA data reports.
Sources: 2006 and 2007 low sulfur light crude oil price: Energy Information Administration (EIA), Form EIA-856, “Monthly Foreign Crude Oil Acquisition Report.” 2006 and 2007 imported crude oil price: EIA, *Annual Energy Review 2007*, DOE/EIA-0384(2007) (Washington, DC, June 2008). 2006 quantities derived from: EIA, *International Energy Annual 2006*, DOE/EIA-0219(2006) (Washington, DC, June-October 2008). **2007 quantities and projections:** EIA, AEO2009 National Energy Modeling System run AEO2009.D120908A and EIA, Generate World Oil Balance Model.

Economic Growth Case Comparisons

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

Supply, Disposition, and Prices	2007	Projections 2010			2020			2030		
		Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth
Production										
Crude Oil and Lease Condensate	10.73	12.19	12.19	12.19	13.81	14.06	14.14	15.51	15.96	16.30
Natural Gas Plant Liquids	2.41	2.55	2.58	2.60	2.46	2.57	2.66	2.45	2.61	2.74
Dry Natural Gas	19.84	20.71	20.95	21.11	21.09	22.08	22.86	22.96	24.26	25.41
Coal[1]	23.50	24.20	24.21	24.22	23.92	24.43	24.81	25.21	26.93	28.52
Nuclear Power	8.41	8.45	8.45	8.45	8.77	8.99	9.27	8.53	9.47	10.67
Hydropower	2.46	2.67	2.67	2.67	2.94	2.95	2.97	2.96	2.97	2.98
Biomass[2]	3.23	4.15	4.20	4.23	6.30	6.52	6.70	7.85	8.25	9.16
Other Renewable Energy[3]	0.97	1.52	1.54	1.81	1.65	1.74	2.05	2.04	2.19	2.71
Other[4]	0.94	0.84	0.85	0.84	0.99	1.07	1.20	1.00	1.15	1.37
Total	**72.49**	**77.27**	**77.64**	**78.10**	**81.93**	**84.41**	**86.67**	**88.52**	**93.79**	**99.85**
Imports										
Crude Oil	21.90	17.49	17.76	18.11	15.20	16.09	17.61	13.05	15.39	17.65
Liquid Fuels and Other Petroleum[5]	6.97	5.51	5.59	5.68	5.07	5.67	6.10	5.40	6.33	7.05
Natural Gas	4.72	3.22	3.27	3.32	3.18	3.37	3.63	2.30	2.58	3.03
Other Imports[6]	0.99	0.89	0.89	0.89	1.09	1.19	1.20	1.14	1.35	1.45
Total	**34.59**	**27.11**	**27.51**	**28.00**	**24.54**	**26.31**	**28.55**	**21.89**	**25.65**	**29.18**
Exports										
Petroleum[7]	2.84	2.51	2.56	2.56	2.86	2.90	2.93	3.12	3.17	3.19
Natural Gas	0.83	0.70	0.70	0.70	1.47	1.44	1.41	1.98	1.87	1.79
Coal	1.51	2.05	2.05	2.05	1.35	1.33	1.33	1.16	1.08	1.07
Total	**5.17**	**5.26**	**5.31**	**5.31**	**5.68**	**5.66**	**5.68**	**6.27**	**6.12**	**6.06**
Discrepancy[8]	**0.01**	**-0.03**	**-0.02**	**0.09**	**-0.28**	**-0.39**	**-0.51**	**-0.06**	**-0.25**	**-0.41**
Consumption										
Liquid Fuels and Other Petroleum[9]	40.75	37.55	37.89	38.36	36.94	38.93	41.27	37.42	41.60	45.63
Natural Gas	23.70	22.90	23.20	23.28	22.88	24.09	25.16	23.35	25.04	26.71
Coal[10]	22.74	22.90	22.91	22.92	23.37	23.98	24.35	24.63	26.56	28.23
Nuclear Power	8.41	8.45	8.45	8.45	8.77	8.99	9.27	8.53	9.47	10.67
Hydropower	2.46	2.67	2.67	2.67	2.94	2.95	2.97	2.96	2.97	2.98
Biomass[11]	2.62	2.95	2.99	3.01	4.35	4.58	4.77	5.12	5.51	6.20
Other Renewable Energy[3]	0.97	1.52	1.54	1.81	1.65	1.74	2.05	2.04	2.19	2.71
Other[12]	0.23	0.21	0.21	0.21	0.17	0.19	0.21	0.15	0.22	0.25
Total	**101.89**	**99.15**	**99.85**	**100.70**	**101.07**	**105.44**	**110.06**	**104.20**	**113.56**	**123.38**
Prices (2007 dollars per unit)										
Petroleum (dollars per barrel)										
Imported Low Sulfur Light Crude Oil Price[13]	72.33	77.68	80.16	78.55	113.36	115.45	116.49	127.30	130.43	135.72
Imported Crude Oil Price[13]	63.83	74.76	77.56	75.89	106.41	112.05	113.50	116.58	124.60	131.46
Natural Gas (dollars per million Btu)										
Price at Henry Hub	6.96	6.47	6.66	6.71	6.84	7.43	7.84	8.72	9.25	9.58
Wellhead Price[14]	6.22	5.72	5.88	5.93	6.04	6.56	6.93	7.70	8.17	8.46
Natural Gas (dollars per thousand cubic feet)										
Wellhead Price[14]	6.39	5.88	6.05	6.10	6.21	6.75	7.12	7.92	8.40	8.70
Coal (dollars per ton)										
Minemouth Price[15]	25.82	29.40	29.45	29.61	27.56	27.90	28.25	27.73	29.10	30.12
Coal (dollars per million Btu)										
Minemouth Price[15]	1.27	1.44	1.44	1.45	1.37	1.39	1.41	1.39	1.46	1.51
Average Delivered Price[16]	1.86	1.98	1.99	1.99	1.96	1.99	2.02	2.01	2.08	2.15
Average Electricity Price (cents per kilowatthour)	9.1	8.9	9.0	9.1	8.9	9.4	9.9	9.7	10.4	10.8

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

Supply, Disposition, and Prices	2007	Projections								
		2010			2020			2030		
		Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth
Prices (nominal dollars per unit)										
Petroleum (dollars per barrel)										
Imported Low Sulfur Light Crude Oil Price[13]	72.33	82.74	84.42	81.67	158.08	149.14	138.14	209.06	189.10	170.81
Imported Crude Oil Price[13]	63.83	79.63	81.69	78.91	148.39	144.74	134.60	191.46	180.66	165.45
Natural Gas (dollars per million Btu)										
Price at Henry Hub	6.96	6.89	7.01	6.98	9.54	9.60	9.30	14.32	13.42	12.06
Wellhead Price[14]	6.22	6.09	6.19	6.17	8.43	8.48	8.21	12.65	11.85	10.65
Natural Gas (dollars per thousand cubic feet)										
Wellhead Price[14]	6.39	6.26	6.37	6.34	8.66	8.72	8.44	13.00	12.18	10.95
Coal (dollars per ton)										
Minemouth Price[15]	25.82	31.31	31.02	30.79	38.44	36.04	33.50	45.55	42.20	37.91
Coal (dollars per million Btu)										
Minemouth Price[15]	1.27	1.53	1.52	1.51	1.91	1.80	1.67	2.28	2.11	1.90
Average Delivered Price[16]	1.86	2.11	2.10	2.07	2.73	2.57	2.39	3.31	3.01	2.71
Average Electricity Price (cents per kilowatthour)	9.1	9.5	9.5	9.4	12.4	12.2	11.8	16.0	15.1	13.7

[1]Includes waste coal.
[2]Includes grid-connected electricity from wood and waste; biomass, such as corn, used for liquid fuels production; and non-electric energy demand from wood. Refer to Table A17 for details.
[3]Includes grid-connected electricity from landfill gas; biogenic municipal waste; wind; photovoltaic and solar thermal sources; and non-electric energy from renewable sources, such as active and passive solar systems. Excludes electricity imports using renewable sources and nonmarketed renewable energy. See Table A17 for selected nonmarketed residential and commercial renewable energy.
[4]Includes non-biogenic municipal waste, liquid hydrogen, methanol, and some domestic inputs to refineries.
[5]Includes imports of finished petroleum products, unfinished oils, alcohols, ethers, blending components, and renewable fuels such as ethanol.
[6]Includes coal, coal coke (net), and electricity (net).
[7]Includes crude oil and petroleum products.
[8]Balancing item. Includes unaccounted for supply, losses, gains, and net storage withdrawals.
[9]Includes petroleum-derived fuels and non-petroleum derived fuels, such as ethanol and biodiesel, and coal-based synthetic liquids. Petroleum coke, which is a solid, is included. Also included are natural gas plant liquids, crude oil consumed as a fuel, and liquid hydrogen. Refer to Table A17 for detailed renewable liquid fuels consumption.
[10]Excludes coal converted to coal-based synthetic liquids.
[11]Includes grid-connected electricity from wood and wood waste, non-electric energy from wood, and biofuels heat and coproducts used in the production of liquid fuels, but excludes the energy content of the liquid fuels.
[12]Includes non-biogenic municipal waste and net electricity imports.
[13]Weighted average price delivered to U.S. refiners.
[14]Represents lower 48 onshore and offshore supplies.
[15]Includes reported prices for both open market and captive mines.
[16]Prices weighted by consumption; weighted average excludes residential and commercial prices, and export free-alongside-ship (f.a.s.) prices.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Data for 2007 are model results and may differ slightly from official EIA data reports.
Sources: 2007 natural gas supply values and natural gas wellhead price: EIA, *Natural Gas Monthly*, DOE/EIA-0130(2008/08) (Washington, DC, August 2008). 2007 coal minemouth and delivered coal prices: EIA, *Annual Coal Report 2007*, DOE/EIA-0584(2007) (Washington, DC, September 2008). 2007 petroleum supply values: EIA, *Petroleum Supply Annual 2007,* DOE/EIA-0340(2007)/1 (Washington, DC, July 2008). 2007 low sulfur light crude oil price: EIA, Form EIA-856, “Monthly Foreign Crude Oil Acquisition Report.” Other 2007 coal values: *Quarterly Coal Report, October-December 2007*, DOE/EIA-0121(2007/4Q) (Washington, DC, March 2008). Other 2007 values: EIA, *Annual Energy Review 2007*, DOE/EIA-0384(2007) (Washington, DC, June 2008). **Projections:** EIA, AEO2009 National Energy Modeling System runs LM2009.D120908A, AEO2009.D120908A, and HM2009.D120908A.

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

Sector and Source	2007	Projections								
		2010			2020			2030		
		Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth
Energy Consumption										
Residential										
Liquefied Petroleum Gases	0.50	0.49	0.49	0.49	0.48	0.49	0.51	0.49	0.52	0.54
Kerosene	0.08	0.08	0.08	0.08	0.07	0.07	0.07	0.07	0.07	0.07
Distillate Fuel Oil	0.78	0.72	0.72	0.72	0.60	0.60	0.60	0.51	0.51	0.51
Liquid Fuels and Other Petroleum Subtotal	1.35	1.29	1.29	1.29	1.15	1.16	1.18	1.07	1.10	1.13
Natural Gas	4.86	4.92	4.92	4.92	5.03	5.10	5.18	4.86	5.07	5.30
Coal	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Renewable Energy[1]	0.43	0.43	0.43	0.43	0.47	0.48	0.49	0.48	0.50	0.53
Electricity	4.75	4.78	4.80	4.81	4.98	5.12	5.25	5.34	5.69	6.07
Delivered Energy	**11.40**	**11.43**	**11.44**	**11.46**	**11.63**	**11.86**	**12.11**	**11.75**	**12.36**	**13.03**
Electricity Related Losses	10.36	10.42	10.44	10.49	10.57	10.81	11.04	11.10	11.69	12.29
Total	**21.76**	**21.85**	**21.88**	**21.95**	**22.20**	**22.67**	**23.15**	**22.85**	**24.05**	**25.32**
Commercial										
Liquefied Petroleum Gases	0.09	0.09	0.09	0.09	0.10	0.10	0.10	0.10	0.10	0.10
Motor Gasoline[2]	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05
Kerosene	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Distillate Fuel Oil	0.41	0.36	0.36	0.36	0.34	0.34	0.35	0.34	0.34	0.35
Residual Fuel Oil	0.08	0.07	0.07	0.07	0.08	0.08	0.08	0.08	0.08	0.08
Liquid Fuels and Other Petroleum Subtotal	0.63	0.58	0.58	0.58	0.58	0.58	0.59	0.58	0.59	0.60
Natural Gas	3.10	3.14	3.14	3.14	3.30	3.34	3.40	3.40	3.54	3.70
Coal	0.07	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06
Renewable Energy[3]	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12
Electricity	4.58	4.74	4.75	4.76	5.42	5.57	5.72	6.01	6.31	6.66
Delivered Energy	**8.50**	**8.65**	**8.66**	**8.67**	**9.48**	**9.69**	**9.90**	**10.18**	**10.62**	**11.14**
Electricity Related Losses	9.99	10.34	10.35	10.38	11.50	11.77	12.02	12.51	12.96	13.49
Total	**18.49**	**18.99**	**19.01**	**19.05**	**20.99**	**21.46**	**21.92**	**22.69**	**23.59**	**24.64**
Industrial[4]										
Liquefied Petroleum Gases	2.35	1.93	2.02	2.12	1.57	1.79	2.03	1.32	1.66	2.04
Motor Gasoline[2]	0.36	0.34	0.34	0.35	0.31	0.34	0.37	0.31	0.36	0.40
Distillate Fuel Oil	1.28	1.15	1.17	1.19	1.08	1.18	1.28	1.08	1.23	1.39
Residual Fuel Oil	0.25	0.15	0.15	0.15	0.15	0.16	0.17	0.14	0.16	0.18
Petrochemical Feedstocks	1.30	0.98	1.01	1.03	0.98	1.13	1.29	0.81	1.05	1.33
Other Petroleum[5]	4.42	3.75	3.74	3.78	3.57	3.72	4.06	3.46	3.84	4.21
Liquid Fuels and Other Petroleum Subtotal	9.96	8.30	8.42	8.62	7.66	8.32	9.21	7.12	8.30	9.55
Natural Gas	6.82	6.59	6.77	6.88	6.32	6.84	7.27	6.05	7.04	8.16
Natural-Gas-to-Liquids Heat and Power	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Lease and Plant Fuel[6]	1.20	1.26	1.27	1.28	1.29	1.33	1.37	1.41	1.47	1.51
Natural Gas Subtotal	8.02	7.85	8.05	8.16	7.61	8.17	8.64	7.45	8.51	9.67
Metallurgical Coal	0.60	0.55	0.55	0.56	0.45	0.49	0.53	0.38	0.48	0.57
Other Industrial Coal	1.21	1.23	1.24	1.24	1.11	1.15	1.19	1.08	1.16	1.23
Coal-to-Liquids Heat and Power	0.00	0.00	0.00	0.00	0.24	0.24	0.24	0.58	0.58	0.59
Net Coal Coke Imports	0.03	0.01	0.01	0.01	0.00	0.01	0.01	0.00	0.01	0.02
Coal Subtotal	1.83	1.79	1.80	1.81	1.81	1.89	1.98	2.05	2.23	2.42
Biofuels Heat and Coproducts	0.40	0.74	0.75	0.75	1.24	1.23	1.22	1.66	1.66	1.92
Renewable Energy[7]	1.64	1.46	1.48	1.50	1.52	1.64	1.76	1.69	1.96	2.24
Electricity	3.43	3.31	3.34	3.37	3.26	3.48	3.71	3.13	3.67	4.23
Delivered Energy	**25.29**	**23.46**	**23.83**	**24.23**	**23.09**	**24.73**	**26.52**	**23.10**	**26.33**	**30.03**
Electricity Related Losses	7.49	7.22	7.27	7.35	6.92	7.36	7.80	6.51	7.55	8.57
Total	**32.77**	**30.68**	**31.10**	**31.58**	**30.01**	**32.09**	**34.33**	**29.61**	**33.87**	**38.60**

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

Sector and Source	2007	Projections								
		2010			2020			2030		
		Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth
Transportation										
Liquefied Petroleum Gases	0.02	0.01	0.01	0.01	0.01	0.01	0.02	0.01	0.02	0.02
E85[8]	0.00	0.00	0.00	0.00	0.94	0.85	0.75	2.11	2.18	2.38
Motor Gasoline[2]	17.29	16.85	16.93	17.05	14.86	15.56	16.35	13.30	14.49	15.33
Jet Fuel[9]	3.23	2.96	3.00	3.05	3.28	3.42	3.57	3.78	4.12	4.40
Distillate Fuel Oil[10]	6.48	6.04	6.13	6.23	6.82	7.36	7.94	7.78	9.09	10.47
Residual Fuel Oil	0.95	0.85	0.86	0.86	0.97	0.98	0.98	0.98	1.00	1.02
Liquid Hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Other Petroleum[11]	0.17	0.17	0.17	0.17	0.17	0.18	0.18	0.18	0.18	0.19
Liquid Fuels and Other Petroleum Subtotal	28.14	26.90	27.11	27.38	27.05	28.36	29.78	28.15	31.09	33.81
Pipeline Fuel Natural Gas	0.64	0.63	0.64	0.65	0.67	0.69	0.71	0.69	0.72	0.75
Compressed Natural Gas	0.02	0.03	0.03	0.03	0.06	0.07	0.07	0.07	0.09	0.10
Electricity	0.02	0.02	0.02	0.02	0.03	0.03	0.03	0.05	0.05	0.05
Delivered Energy	**28.82**	**27.59**	**27.81**	**28.08**	**27.81**	**29.15**	**30.59**	**28.95**	**31.94**	**34.72**
Electricity Related Losses	0.05	0.05	0.05	0.05	0.07	0.07	0.07	0.10	0.10	0.11
Total	**28.87**	**27.64**	**27.86**	**28.13**	**27.88**	**29.22**	**30.67**	**29.05**	**32.05**	**34.83**
Delivered Energy Consumption for All Sectors										
Liquefied Petroleum Gases	2.95	2.52	2.61	2.72	2.16	2.39	2.65	1.92	2.29	2.70
E85[8]	0.00	0.00	0.00	0.00	0.94	0.85	0.75	2.11	2.18	2.38
Motor Gasoline[2]	17.70	17.24	17.33	17.44	15.22	15.95	16.77	13.66	14.90	15.79
Jet Fuel[9]	3.23	2.96	3.00	3.05	3.28	3.42	3.57	3.78	4.12	4.40
Kerosene	0.11	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10
Distillate Fuel Oil	8.94	8.27	8.38	8.50	8.84	9.49	10.17	9.70	11.17	12.71
Residual Fuel Oil	1.28	1.07	1.07	1.08	1.20	1.22	1.24	1.21	1.25	1.28
Petrochemical Feedstocks	1.30	0.98	1.01	1.03	0.98	1.13	1.29	0.81	1.05	1.33
Liquid Hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Other Petroleum[12]	4.57	3.90	3.89	3.93	3.73	3.89	4.23	3.62	4.01	4.38
Liquid Fuels and Other Petroleum Subtotal	40.08	37.06	37.40	37.87	36.44	38.42	40.76	36.91	41.07	45.09
Natural Gas	14.79	14.69	14.86	14.98	14.70	15.34	15.92	14.38	15.73	17.25
Natural-Gas-to-Liquids Heat and Power	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Lease and Plant Fuel[6]	1.20	1.26	1.27	1.28	1.29	1.33	1.37	1.41	1.47	1.51
Pipeline Natural Gas	0.64	0.63	0.64	0.65	0.67	0.69	0.71	0.69	0.72	0.75
Natural Gas Subtotal	16.64	16.58	16.78	16.90	16.66	17.36	18.00	16.47	17.92	19.52
Metallurgical Coal	0.60	0.55	0.55	0.56	0.45	0.49	0.53	0.38	0.48	0.57
Other Coal	1.28	1.30	1.31	1.32	1.18	1.22	1.27	1.15	1.23	1.31
Coal-to-Liquids Heat and Power	0.00	0.00	0.00	0.00	0.24	0.24	0.24	0.58	0.58	0.59
Net Coal Coke Imports	0.03	0.01	0.01	0.01	0.00	0.01	0.01	0.00	0.01	0.02
Coal Subtotal	1.91	1.86	1.87	1.89	1.88	1.97	2.05	2.12	2.30	2.49
Biofuels Heat and Coproducts	0.40	0.74	0.75	0.75	1.24	1.23	1.22	1.66	1.66	1.92
Renewable Energy[13]	2.19	2.01	2.03	2.05	2.12	2.24	2.38	2.30	2.58	2.89
Electricity	12.79	12.86	12.91	12.98	13.68	14.20	14.72	14.53	15.73	17.01
Delivered Energy	**74.01**	**71.13**	**71.74**	**72.44**	**72.01**	**75.42**	**79.12**	**73.99**	**81.26**	**88.92**
Electricity Related Losses	27.88	28.03	28.11	28.26	29.06	30.02	30.93	30.21	32.30	34.47
Total	**101.89**	**99.15**	**99.85**	**100.70**	**101.07**	**105.44**	**110.06**	**104.20**	**113.56**	**123.38**
Electric Power[14]										
Distillate Fuel Oil	0.11	0.11	0.11	0.11	0.12	0.12	0.12	0.12	0.13	0.13
Residual Fuel Oil	0.56	0.38	0.38	0.38	0.38	0.39	0.39	0.39	0.40	0.41
Liquid Fuels and Other Petroleum Subtotal	0.67	0.49	0.49	0.49	0.50	0.51	0.51	0.51	0.53	0.54
Natural Gas	7.06	6.32	6.42	6.38	6.22	6.73	7.16	6.87	7.12	7.20
Steam Coal	20.84	21.04	21.03	21.03	21.49	22.01	22.30	22.51	24.25	25.74
Nuclear Power	8.41	8.45	8.45	8.45	8.77	8.99	9.27	8.53	9.47	10.67
Renewable Energy[15]	3.45	4.38	4.42	4.68	5.59	5.79	6.20	6.17	6.43	7.08
Electricity Imports	0.11	0.08	0.08	0.08	0.04	0.06	0.08	0.02	0.10	0.13
Total[16]	**40.67**	**40.89**	**41.02**	**41.24**	**42.74**	**44.22**	**45.65**	**44.74**	**48.03**	**51.48**

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

Sector and Source	2007	2010 Low Economic Growth	2010 Reference	2010 High Economic Growth	2020 Low Economic Growth	2020 Reference	2020 High Economic Growth	2030 Low Economic Growth	2030 Reference	2030 High Economic Growth
Total Energy Consumption										
Liquefied Petroleum Gases	2.95	2.52	2.61	2.72	2.16	2.39	2.65	1.92	2.29	2.70
E85[8]	0.00	0.00	0.00	0.00	0.94	0.85	0.75	2.11	2.18	2.38
Motor Gasoline[2]	17.70	17.24	17.33	17.44	15.22	15.95	16.77	13.66	14.90	15.79
Jet Fuel[9]	3.23	2.96	3.00	3.05	3.28	3.42	3.57	3.78	4.12	4.40
Kerosene	0.11	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10
Distillate Fuel Oil	9.05	8.39	8.49	8.62	8.96	9.61	10.29	9.83	11.31	12.85
Residual Fuel Oil	1.84	1.45	1.45	1.46	1.58	1.60	1.63	1.60	1.64	1.69
Petrochemical Feedstocks	1.30	0.98	1.01	1.03	0.98	1.13	1.29	0.81	1.05	1.33
Liquid Hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Other Petroleum[12]	4.57	3.90	3.89	3.93	3.73	3.89	4.23	3.62	4.01	4.38
Liquid Fuels and Other Petroleum Subtotal	40.75	37.55	37.89	38.36	36.94	38.93	41.27	37.42	41.60	45.63
Natural Gas	21.86	21.01	21.29	21.36	20.92	22.07	23.09	21.25	22.86	24.45
Natural-Gas-to-Liquids Heat and Power	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Lease and Plant Fuel[6]	1.20	1.26	1.27	1.28	1.29	1.33	1.37	1.41	1.47	1.51
Pipeline Natural Gas	0.64	0.63	0.64	0.65	0.67	0.69	0.71	0.69	0.72	0.75
Natural Gas Subtotal	23.70	22.90	23.20	23.28	22.88	24.09	25.16	23.35	25.04	26.71
Metallurgical Coal	0.60	0.55	0.55	0.56	0.45	0.49	0.53	0.38	0.48	0.57
Other Coal	22.12	22.35	22.34	22.35	22.67	23.24	23.57	23.66	25.49	27.04
Coal-to-Liquids Heat and Power	0.00	0.00	0.00	0.00	0.24	0.24	0.24	0.58	0.58	0.59
Net Coal Coke Imports	0.03	0.01	0.01	0.01	0.00	0.01	0.01	0.00	0.01	0.02
Coal Subtotal	22.74	22.90	22.91	22.92	23.37	23.98	24.35	24.63	26.56	28.23
Nuclear Power	8.41	8.45	8.45	8.45	8.77	8.99	9.27	8.53	9.47	10.67
Biofuels Heat and Coproducts	0.40	0.74	0.75	0.75	1.24	1.23	1.22	1.66	1.66	1.92
Renewable Energy[17]	5.65	6.40	6.45	6.74	7.71	8.03	8.57	8.47	9.01	9.97
Electricity Imports	0.11	0.08	0.08	0.08	0.04	0.06	0.08	0.02	0.10	0.13
Total	**101.89**	**99.15**	**99.85**	**100.70**	**101.07**	**105.44**	**110.06**	**104.20**	**113.56**	**123.38**
Energy Use and Related Statistics										
Delivered Energy Use	74.01	71.13	71.74	72.44	72.01	75.42	79.12	73.99	81.26	88.92
Total Energy Use	101.89	99.15	99.85	100.70	101.07	105.44	110.06	104.20	113.56	123.38
Ethanol Consumed in Motor Gasoline and E85	0.56	1.08	1.08	1.09	1.67	1.66	1.65	2.34	2.47	2.67
Population (millions)	302.41	309.98	311.37	313.17	330.15	342.61	356.39	345.43	375.12	406.67
Gross Domestic Product (billion 2000 dollars)	11524	11453	11779	12114	14327	15524	16726	17351	20114	22875
Carbon Dioxide Emissions (million metric tons)	5990.8	5769.9	5801.4	5831.1	5745.9	5982.3	6209.9	5897.9	6414.4	6885.9

[1]Includes wood used for residential heating. See Table A4 and/or Table A17 for estimates of nonmarketed renewable energy consumption for geothermal heat pumps, solar thermal hot water heating, and solar photovoltaic electricity generation.
[2]Includes ethanol (blends of 10 percent or less) and ethers blended into gasoline.
[3]Excludes ethanol. Includes commercial sector consumption of wood and wood waste, landfill gas, municipal waste, and other biomass for combined heat and power. See Table A5 and/or Table A17 for estimates of nonmarketed renewable energy consumption for solar thermal hot water heating and solar photovoltaic electricity generation.
[4]Includes energy for combined heat and power plants, except those whose primary business is to sell electricity, or electricity and heat, to the public.
[5]Includes petroleum coke, asphalt, road oil, lubricants, still gas, and miscellaneous petroleum products.
[6]Represents natural gas used in well, field, and lease operations, and in natural gas processing plant machinery.
[7]Includes consumption of energy produced from hydroelectric, wood and wood waste, municipal waste, and other biomass sources. Excludes ethanol blends (10 percent or less) in motor gasoline.
[8]E85 refers to a blend of 85 percent ethanol (renewable) and 15 percent motor gasoline (nonrenewable). To address cold starting issues, the percentage of ethanol varies seasonally. The annual average ethanol content of 74 percent is used for this forecast.
[9]Includes only kerosene type.
[10]Diesel fuel for on- and off- road use.
[11]Includes aviation gasoline and lubricants.
[12]Includes unfinished oils, natural gasoline, motor gasoline blending components, aviation gasoline, lubricants, still gas, asphalt, road oil, petroleum coke, and miscellaneous petroleum products.
[13]Includes electricity generated for sale to the grid and for own use from renewable sources, and non-electric energy from renewable sources. Excludes ethanol and nonmarketed renewable energy consumption for geothermal heat pumps, buildings photovoltaic systems, and solar thermal hot water heaters.
[14]Includes consumption of energy by electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public. Includes small power producers and exempt wholesale generators.
[15]Includes conventional hydroelectric, geothermal, wood and wood waste, biogenic municipal waste, other biomass, wind, photovoltaic, and solar thermal sources. Excludes net electricity imports.
[16]Includes non-biogenic municipal waste not included above.
[17]Includes conventional hydroelectric, geothermal, wood and wood waste, biogenic municipal waste, other biomass, wind, photovoltaic, and solar thermal sources. Excludes ethanol, net electricity imports, and nonmarketed renewable energy consumption for geothermal heat pumps, buildings photovoltaic systems, and solar thermal hot water heaters.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Data for 2007 are model results and may differ slightly from official EIA data reports.
Sources: 2007 consumption based on: Energy Information Administration (EIA), *Annual Energy Review 2007*, DOE/EIA-0384(2007) (Washington, DC, June 2008). 2007 population and gross domestic product: IHS Global Insight Industry and Employment models, November 2008. 2007 carbon dioxide emissions: EIA, *Emissions of Greenhouse Gases in the United States 2007,* DOE/EIA-0573(2007) (Washington, DC, December 2008). **Projections:** EIA, AEO2009 National Energy Modeling System runs LM2009.D120908A, AEO2009.D120908A, and HM2009.D120908A.

Table B3. Energy Prices by Sector and Source
(2007 Dollars per Million Btu, Unless Otherwise Noted)

Sector and Source	2007	Projections								
		2010			2020			2030		
		Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth
Residential										
Liquefied Petroleum Gases	24.98	25.33	25.86	25.52	31.79	32.88	33.08	33.52	35.11	36.58
Distillate Fuel Oil	19.66	18.23	18.69	18.38	22.98	24.10	24.43	25.16	26.67	28.13
Natural Gas	12.69	11.90	12.09	12.18	11.89	12.50	12.91	13.72	14.31	14.69
Electricity	31.19	30.65	30.89	31.07	31.22	32.72	34.31	33.52	35.84	37.37
Commercial										
Liquefied Petroleum Gases	23.04	22.15	22.69	22.34	28.54	29.60	29.79	30.22	31.77	33.21
Distillate Fuel Oil	16.05	15.68	16.15	15.83	21.04	22.11	22.45	23.07	24.69	26.13
Residual Fuel Oil	10.21	10.52	10.97	10.67	16.20	16.68	16.81	17.64	17.98	18.38
Natural Gas	10.99	10.36	10.55	10.63	10.47	11.13	11.60	12.27	12.96	13.42
Electricity	28.07	27.00	27.29	27.52	26.41	28.15	29.82	28.68	31.01	32.54
Industrial[1]										
Liquefied Petroleum Gases	23.38	21.29	21.84	21.48	27.76	28.78	28.95	29.31	30.99	32.44
Distillate Fuel Oil	16.82	15.54	16.01	15.69	21.53	22.56	22.92	23.51	25.19	26.62
Residual Fuel Oil	10.49	14.92	15.38	15.09	20.08	20.94	21.19	21.64	22.73	23.87
Natural Gas[2]	7.52	6.76	6.91	6.95	6.95	7.48	7.83	8.62	9.07	9.39
Metallurgical Coal	3.61	4.37	4.37	4.39	4.33	4.40	4.44	4.36	4.41	4.48
Other Industrial Coal	2.43	2.53	2.54	2.54	2.50	2.53	2.57	2.56	2.67	2.76
Coal to Liquids	- -	- -	- -	- -	1.23	1.23	1.26	1.48	1.36	1.39
Electricity	18.63	18.51	18.72	18.88	17.78	19.06	20.50	19.62	21.59	22.60
Transportation										
Liquefied Petroleum Gases[3]	25.01	25.13	25.67	25.33	31.53	32.62	32.83	33.20	34.77	36.24
E85[4]	26.67	24.93	25.47	25.14	28.24	29.30	29.62	28.65	30.10	30.94
Motor Gasoline[5]	22.98	22.99	23.47	23.17	28.68	29.75	30.14	30.42	32.10	33.71
Jet Fuel[6]	16.10	15.54	16.03	15.71	21.27	22.15	22.50	23.23	24.63	25.95
Diesel Fuel (distillate fuel oil)[7]	20.92	19.55	20.05	19.74	24.96	26.04	26.53	26.75	28.59	30.20
Residual Fuel Oil	9.35	11.65	12.10	11.86	16.66	17.46	17.68	18.70	19.65	20.87
Natural Gas[8]	15.46	14.71	14.90	14.99	14.20	14.90	15.46	15.53	16.24	16.82
Electricity	30.64	29.99	30.34	30.56	27.79	29.48	31.35	31.10	34.15	35.68
Electric Power[9]										
Distillate Fuel Oil	14.77	14.64	15.09	14.79	19.42	20.45	20.78	21.69	23.11	24.53
Residual Fuel Oil	8.38	12.75	13.21	12.94	17.77	18.55	18.79	19.71	20.67	21.81
Natural Gas	7.02	6.40	6.59	6.65	6.59	7.15	7.53	8.23	8.70	9.02
Steam Coal	1.78	1.89	1.89	1.89	1.89	1.92	1.94	1.97	2.04	2.11
Average Price to All Users[10]										
Liquefied Petroleum Gases	18.53	20.52	20.96	20.60	26.70	27.56	27.64	28.53	29.77	30.85
E85[4]	26.67	24.93	25.47	25.14	28.24	29.30	29.62	28.65	30.10	30.94
Motor Gasoline[5]	22.82	22.99	23.47	23.17	28.68	29.75	30.14	30.42	32.10	33.70
Jet Fuel	16.10	15.54	16.03	15.71	21.27	22.15	22.50	23.23	24.63	25.95
Distillate Fuel Oil	19.94	18.49	18.98	18.68	24.18	25.28	25.74	26.12	27.94	29.55
Residual Fuel Oil	9.25	12.21	12.66	12.41	17.22	18.03	18.26	19.16	20.12	21.29
Natural Gas	9.01	8.40	8.56	8.62	8.61	9.11	9.46	10.27	10.75	11.07
Metallurgical Coal	3.61	4.37	4.37	4.39	4.33	4.40	4.44	4.36	4.41	4.48
Other Coal	1.82	1.93	1.93	1.93	1.93	1.95	1.98	2.00	2.07	2.14
Coal to Liquids	- -	- -	- -	- -	1.23	1.23	1.26	1.48	1.36	1.39
Electricity	26.70	26.18	26.42	26.60	26.11	27.57	29.07	28.52	30.56	31.80
Non-Renewable Energy Expenditures by Sector (billion 2007 dollars)										
Residential	238.38	232.16	235.27	236.76	245.77	263.30	280.31	276.47	310.03	340.96
Commercial	173.09	170.43	172.88	174.43	190.63	207.76	224.08	228.34	256.75	282.60
Industrial	226.84	195.79	204.25	208.24	209.85	242.68	274.85	217.46	276.26	339.95
Transportation	596.75	563.59	580.97	578.11	687.05	752.82	806.73	724.88	853.25	976.29
Total Non-Renewable Expenditures	1235.06	1161.96	1193.36	1197.55	1333.29	1466.55	1585.97	1447.15	1696.29	1939.79
Transportation Renewable Expenditures	0.04	0.06	0.07	0.07	26.65	24.83	22.10	60.50	65.71	73.63
Total Expenditures	**1235.10**	**1162.03**	**1193.43**	**1197.61**	**1359.95**	**1491.38**	**1608.07**	**1507.65**	**1762.00**	**2013.43**

Table B3. Energy Prices by Sector and Source (Continued)
(Nominal Dollars per Million Btu, Unless Otherwise Noted)

Sector and Source	2007	Projections								
		2010			2020			2030		
		Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth
Residential										
Liquefied Petroleum Gases	24.98	26.98	27.24	26.53	44.34	42.47	39.23	55.06	50.90	46.04
Distillate Fuel Oil	19.66	19.42	19.68	19.11	32.05	31.14	28.97	41.32	38.67	35.40
Natural Gas	12.69	12.67	12.74	12.66	16.58	16.14	15.31	22.53	20.75	18.49
Electricity	31.19	32.65	32.53	32.31	43.54	42.26	40.69	55.05	51.96	47.03
Commercial										
Liquefied Petroleum Gases	23.04	23.59	23.89	23.23	39.80	38.24	35.32	49.63	46.06	41.79
Distillate Fuel Oil	16.05	16.70	17.01	16.46	29.35	28.56	26.62	37.88	35.80	32.89
Residual Fuel Oil	10.21	11.20	11.55	11.10	22.59	21.55	19.94	28.97	26.07	23.13
Natural Gas	10.99	11.03	11.11	11.05	14.60	14.37	13.75	20.16	18.78	16.89
Electricity	28.07	28.76	28.74	28.62	36.83	36.37	35.37	47.10	44.96	40.95
Industrial[1]										
Liquefied Petroleum Gases	23.38	22.68	23.00	22.34	38.71	37.17	34.32	48.13	44.93	40.82
Distillate Fuel Oil	16.82	16.55	16.86	16.32	30.03	29.14	27.18	38.61	36.52	33.50
Residual Fuel Oil	10.49	15.89	16.20	15.69	28.00	27.05	25.13	35.54	32.95	30.04
Natural Gas[2]	7.52	7.20	7.27	7.23	9.70	9.66	9.29	14.15	13.16	11.82
Metallurgical Coal	3.61	4.65	4.60	4.57	6.04	5.69	5.27	7.17	6.40	5.64
Other Industrial Coal	2.43	2.69	2.67	2.64	3.49	3.27	3.04	4.20	3.88	3.47
Coal to Liquids	- -	- -	- -	- -	1.72	1.59	1.49	2.44	1.98	1.75
Electricity	18.63	19.72	19.72	19.63	24.79	24.63	24.30	32.22	31.30	28.44
Transportation										
Liquefied Petroleum Gases[3]	25.01	26.77	27.04	26.34	43.98	42.13	38.93	54.52	50.41	45.61
E85[4]	26.67	26.55	26.83	26.14	39.38	37.85	35.12	47.06	43.63	38.94
Motor Gasoline[5]	22.98	24.49	24.72	24.09	40.00	38.43	35.75	49.96	46.54	42.42
Jet Fuel[6]	16.10	16.55	16.89	16.34	29.66	28.62	26.68	38.15	35.70	32.66
Diesel Fuel (distillate fuel oil)[7]	20.92	20.82	21.12	20.52	34.81	33.63	31.47	43.93	41.44	38.00
Residual Fuel Oil	9.35	12.41	12.74	12.33	23.23	22.56	20.96	30.72	28.49	26.27
Natural Gas[8]	15.46	15.67	15.69	15.59	19.80	19.24	18.33	25.50	23.55	21.17
Electricity	30.64	31.94	31.95	31.78	38.75	38.09	37.18	51.07	49.51	44.90
Electric Power[9]										
Distillate Fuel Oil	14.77	15.59	15.89	15.38	27.07	26.42	24.64	35.62	33.51	30.87
Residual Fuel Oil	8.38	13.58	13.91	13.46	24.78	23.97	22.28	32.36	29.97	27.44
Natural Gas	7.02	6.82	6.94	6.92	9.19	9.24	8.94	13.51	12.61	11.35
Steam Coal	1.78	2.01	1.99	1.97	2.64	2.48	2.30	3.24	2.95	2.65

Table B3. Energy Prices by Sector and Source (Continued)
(Nominal Dollars per Million Btu, Unless Otherwise Noted)

Sector and Source	2007	Projections								
		2010			2020			2030		
		Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth
Average Price to All Users[10]										
Liquefied Petroleum Gases	18.53	21.85	22.07	21.42	37.24	35.61	32.78	46.86	43.16	38.83
E85[4]	26.67	26.55	26.83	26.14	39.38	37.85	35.12	47.06	43.63	38.94
Motor Gasoline[5]	22.82	24.49	24.71	24.09	40.00	38.43	35.74	49.95	46.54	42.42
Jet Fuel	16.10	16.55	16.89	16.34	29.66	28.62	26.68	38.15	35.70	32.66
Distillate Fuel Oil	19.94	19.69	19.99	19.42	33.72	32.65	30.53	42.89	40.51	37.19
Residual Fuel Oil	9.25	13.00	13.34	12.91	24.02	23.29	21.66	31.46	29.16	26.80
Natural Gas	9.01	8.95	9.01	8.96	12.00	11.77	11.22	16.86	15.58	13.93
Metallurgical Coal	3.61	4.65	4.60	4.57	6.04	5.69	5.27	7.17	6.40	5.64
Other Coal	1.82	2.05	2.04	2.01	2.69	2.52	2.34	3.29	3.00	2.69
Coal to Liquids	- -	- -	- -	- -	1.72	1.59	1.49	2.44	1.98	1.75
Electricity	26.70	27.88	27.82	27.66	36.41	35.62	34.48	46.83	44.31	40.02
Non-Renewable Energy Expenditures by Sector (billion nominal dollars)										
Residential	238.38	247.28	247.78	246.19	342.73	340.12	332.40	454.04	449.49	429.11
Commercial	173.09	181.52	182.07	181.38	265.84	268.38	265.72	375.00	372.25	355.66
Industrial	226.84	208.54	215.12	216.54	292.64	313.49	325.93	357.14	400.54	427.84
Transportation	596.75	600.28	611.87	601.14	958.10	972.48	956.66	1190.47	1237.08	1228.71
Total Non-Renewable Expenditures	1235.06	1237.62	1256.84	1245.25	1859.30	1894.47	1880.71	2376.64	2459.36	2441.32
Transportation Renewable Expenditures	0.04	0.07	0.07	0.07	37.17	32.08	26.21	99.35	95.27	92.67
Total Expenditures	**1235.10**	**1237.69**	**1256.91**	**1245.32**	**1896.47**	**1926.55**	**1906.92**	**2476.00**	**2554.63**	**2533.99**

[1]Includes energy for combined heat and power plants, except those whose primary business is to sell electricity, or electricity and heat, to the public.
[2]Excludes use for lease and plant fuel.
[3]Includes Federal and State taxes while excluding county and local taxes.
[4]E85 refers to a blend of 85 percent ethanol (renewable) and 15 percent motor gasoline (nonrenewable). To address cold starting issues, the percentage of ethanol varies seasonally. The annual average ethanol content of 74 percent is used for this forecast.
[5]Sales weighted-average price for all grades. Includes Federal, State and local taxes.
[6]Kerosene-type jet fuel. Includes Federal and State taxes while excluding county and local taxes.
[7]Diesel fuel for on-road use. Includes Federal and State taxes while excluding county and local taxes.
[8]Compressed natural gas used as a vehicle fuel. Includes estimated motor vehicle fuel taxes and estimated dispensing costs or charges.
[9]Includes electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public.
[10]Weighted averages of end-use fuel prices are derived from the prices shown in each sector and the corresponding sectoral consumption.
Btu = British thermal unit.
- - = Not applicable.
Note: Data for 2007 are model results and may differ slightly from official EIA data reports.
Sources: 2007 prices for motor gasoline, distillate fuel oil, and jet fuel are based on prices in the Energy Information Administration (EIA), *Petroleum Marketing Annual 2007*, DOE/EIA-0487(2007) (Washington, DC, August 2008). 2007 residential and commercial natural gas delivered prices: EIA, *Natural Gas Monthly*, DOE/EIA-0130(2008/08) (Washington, DC, August 2008). 2007 industrial natural gas delivered prices are estimated based on: EIA, *Manufacturing Energy Consumption Survey 1994* and industrial and wellhead prices from the *Natural Gas Annual 2006*, DOE/EIA-0131(2006) (Washington, DC, October 2007) and the *Natural Gas Monthly*, DOE/EIA-0130(2008/08) (Washington, DC, August 2008). 2007 transportation sector natural gas delivered prices are model results. 2007 electric power sector natural gas prices: EIA, *Electric Power Monthly*, DOE/EIA-0226, April 2007 and April 2008, Table 4.13.B. 2007 coal prices based on: EIA, *Quarterly Coal Report, October-December 2007*, DOE/EIA-0121(2007/4Q) (Washington, DC, March 2008) and EIA, AEO2009 National Energy Modeling System run AEO2009.D120908A. 2007 electricity prices: EIA, *Annual Energy Review 2007*, DOE/EIA-0384(2007) (Washington, DC, June 2008). 2007 E85 prices derived from monthly prices in the Clean Cities Alternative Fuel Price Report.
Projections: EIA, AEO2009 National Energy Modeling System runs LM2009.D120908A, AEO2009.D120908A, and HM2009.D120908A.

Table B4. Macroeconomic Indicators
(Billion 2000 Chain-Weighted Dollars, Unless Otherwise Noted)

Indicators	2007	2010 Low Economic Growth	2010 Reference	2010 High Economic Growth	2020 Low Economic Growth	2020 Reference	2020 High Economic Growth	2030 Low Economic Growth	2030 Reference	2030 High Economic Growth
Real Gross Domestic Product	**11524**	**11453**	**11779**	**12114**	**14327**	**15524**	**16726**	**17351**	**20114**	**22875**
Components of Real Gross Domestic Product										
Real Consumption	8253	8270	8435	8607	10121	10876	11639	11826	13439	15054
Real Investment	1810	1438	1581	1728	2270	2565	2856	3004	3756	4478
Real Government Spending	2012	2033	2065	2096	2058	2194	2329	2129	2427	2722
Real Exports	1426	1574	1585	1597	2765	3061	3365	4906	5820	6757
Real Imports	1972	1861	1899	1947	2874	3007	3111	4413	4717	4961
Energy Intensity (thousand Btu per 2000 dollar of GDP)										
Delivered Energy	6.42	6.21	6.09	5.98	5.03	4.86	4.73	4.26	4.04	3.89
Total Energy	8.84	8.66	8.48	8.31	7.05	6.79	6.58	6.01	5.65	5.39
Price Indices										
GDP Chain-Type Price Index (2000=1.000)	1.198	1.276	1.262	1.246	1.671	1.548	1.421	1.968	1.737	1.508
Consumer Price Index (1982-4=1)										
All-Urban	2.07	2.22	2.20	2.17	3.05	2.83	2.60	3.74	3.31	2.88
Energy Commodities and Services	2.08	2.17	2.18	2.15	3.28	3.16	2.97	4.14	3.87	3.51
Wholesale Price Index (1982=1.00)										
All Commodities	1.73	1.82	1.80	1.76	2.39	2.19	1.98	2.75	2.36	1.99
Fuel and Power	1.77	1.90	1.91	1.88	2.82	2.74	2.60	3.70	3.45	3.14
Metals and Metal Products	1.93	1.84	1.82	1.80	2.37	2.21	2.05	2.50	2.22	1.97
Interest Rates (percent, nominal)										
Federal Funds Rate	5.02	1.36	1.30	1.15	5.72	5.20	4.63	4.49	4.04	3.60
10-Year Treasury Note	4.63	3.89	3.67	3.36	6.43	5.86	5.24	5.19	4.67	4.18
AA Utility Bond Rate	5.94	6.56	6.39	6.12	8.06	7.49	6.86	6.35	5.79	5.24
Value of Shipments (billion 2000 dollars)										
Total Industrial	5750	5069	5240	5418	6132	6753	7383	6923	8451	10032
Non-manufacturing	1490	1196	1277	1361	1411	1603	1795	1498	1780	2057
Manufacturing	4261	3873	3963	4058	4721	5150	5588	5425	6671	7975
Energy-Intensive	1239	1215	1238	1265	1277	1374	1481	1319	1525	1743
Non-Energy Intensive	3022	2658	2725	2793	3444	3776	4106	4106	5145	6232
Population and Employment (millions)										
Population with Armed Forces Overseas	302.4	310.0	311.4	313.2	330.2	342.6	356.4	345.4	375.1	406.7
Population (aged 16 and over)	237.2	243.8	245.2	247.0	261.8	270.4	279.7	278.2	297.6	318.3
Population, over age 65	38.0	40.2	40.4	40.5	54.2	55.0	56.0	69.9	72.3	74.8
Employment, Nonfarm	137.2	130.7	135.6	140.6	141.7	152.6	163.5	153.1	168.3	183.5
Employment, Manufacturing	13.9	12.0	12.2	12.4	11.8	12.3	12.6	10.7	11.7	12.6
Key Labor Indicators										
Labor Force (millions)	153.1	154.2	155.9	157.4	162.9	168.4	174.5	171.9	181.5	191.4
Non-farm Labor Productivity (1992=1.00)	1.37	1.43	1.45	1.47	1.65	1.74	1.84	1.92	2.14	2.36
Unemployment Rate (percent)	4.64	8.42	8.26	8.08	5.72	5.53	5.30	4.98	4.78	4.58
Key Indicators for Energy Demand										
Real Disposable Personal Income	8644	8837	9017	9209	11317	12035	12757	13927	15450	16980
Housing Starts (millions)	1.44	1.01	1.18	1.37	1.40	1.77	2.16	1.18	1.74	2.31
Commercial Floorspace (billion square feet)	77.3	80.9	81.2	81.4	88.3	92.3	96.2	96.2	103.3	110.6
Unit Sales of Light-Duty Vehicles (millions)	16.09	13.90	14.18	14.89	16.30	17.41	18.88	18.52	20.99	23.77

GDP = Gross domestic product.
Btu = British thermal unit.
Sources: 2007: IHS Global Insight Industry and Employment models, November 2008. **Projections:** Energy Information Administration, AEO2009 National Energy Modeling System runs LM2009.D120908A, AEO2009.D120908A, and HM2009.D120908A.

Price Case Comparisons

Table C1. Total Energy Supply and Disposition Summary
(Quadrillion Btu per Year, Unless Otherwise Noted)

Supply, Disposition, and Prices	2007	Projections								
		2010			2020			2030		
		Low Oil Price	Reference	High Oil Price	Low Oil Price	Reference	High Oil Price	Low Oil Price	Reference	High Oil Price
Production										
Crude Oil and Lease Condensate	10.73	12.19	12.19	12.20	11.60	14.06	15.54	11.60	15.96	18.31
Natural Gas Plant Liquids	2.41	2.60	2.58	2.57	2.55	2.57	2.59	2.42	2.61	2.67
Dry Natural Gas	19.84	21.09	20.95	20.88	21.20	22.08	22.47	22.86	24.26	26.04
Coal[1]	23.50	24.22	24.21	24.18	24.89	24.43	24.03	26.18	26.93	26.40
Nuclear Power	8.41	8.45	8.45	8.45	8.89	8.99	9.10	9.14	9.47	9.57
Hydropower	2.46	2.67	2.67	2.67	2.97	2.95	2.95	2.98	2.97	2.98
Biomass[2]	3.23	4.20	4.20	4.23	6.28	6.52	7.50	7.81	8.25	8.63
Other Renewable Energy[3]	0.97	1.50	1.54	1.59	1.71	1.74	1.77	2.22	2.19	2.20
Other[4]	0.94	0.85	0.85	0.89	1.07	1.07	1.28	1.15	1.15	1.21
Total	**72.49**	**77.77**	**77.64**	**77.66**	**81.15**	**84.41**	**87.24**	**86.37**	**93.79**	**98.02**
Imports										
Crude Oil	21.90	18.05	17.76	17.59	21.51	16.09	12.08	24.99	15.39	9.64
Liquid Fuels and Other Petroleum[5]	6.97	6.07	5.59	5.53	7.07	5.67	5.33	7.58	6.33	5.74
Natural Gas	4.72	3.27	3.27	3.27	3.90	3.37	3.21	3.27	2.58	2.15
Other Imports[6]	0.99	0.89	0.89	0.89	0.57	1.19	1.43	1.12	1.35	1.67
Total	**34.59**	**28.28**	**27.51**	**27.28**	**33.06**	**26.31**	**22.05**	**36.96**	**25.65**	**19.19**
Exports										
Petroleum[7]	2.84	2.58	2.56	2.55	2.81	2.90	2.90	3.18	3.17	2.96
Natural Gas	0.83	0.70	0.70	0.70	1.48	1.44	1.41	1.97	1.87	1.80
Coal	1.51	2.05	2.05	2.05	1.34	1.33	1.23	1.09	1.08	0.82
Total	**5.17**	**5.33**	**5.31**	**5.30**	**5.64**	**5.66**	**5.54**	**6.24**	**6.12**	**5.57**
Discrepancy[8]	**0.01**	**-0.09**	**-0.02**	**0.01**	**-0.52**	**-0.39**	**-0.25**	**-0.52**	**-0.25**	**-0.16**
Consumption										
Liquid Fuels and Other Petroleum[9]	40.75	38.73	37.89	37.72	43.21	38.93	36.87	47.48	41.60	38.83
Natural Gas	23.70	23.34	23.20	23.10	23.70	24.09	24.18	24.23	25.04	25.72
Coal[10]	22.74	22.92	22.91	22.88	23.93	23.98	23.86	25.99	26.56	26.53
Nuclear Power	8.41	8.45	8.45	8.45	8.89	8.99	9.10	9.14	9.47	9.57
Hydropower	2.46	2.67	2.67	2.67	2.97	2.95	2.95	2.98	2.97	2.98
Biomass[11]	2.62	2.99	2.99	3.00	4.51	4.58	5.04	5.35	5.51	5.72
Other Renewable Energy[3]	0.97	1.50	1.54	1.59	1.71	1.74	1.77	2.22	2.19	2.20
Other[12]	0.23	0.21	0.21	0.22	0.17	0.19	0.22	0.21	0.22	0.25
Total	**101.89**	**100.80**	**99.85**	**99.62**	**109.09**	**105.44**	**104.00**	**117.61**	**113.56**	**111.80**
Prices (2007 dollars per unit)										
Petroleum (dollars per barrel)										
Imported Low Sulfur Light Crude Oil Price[13]	72.33	58.61	80.16	91.08	50.43	115.45	184.60	50.23	130.43	200.42
Imported Crude Oil Price[13]	63.83	55.45	77.56	88.31	46.77	112.05	181.18	46.44	124.60	197.72
Natural Gas (dollars per million Btu)										
Price at Henry Hub	6.96	6.08	6.66	6.89	6.93	7.43	7.80	8.70	9.25	9.62
Wellhead Price[14]	6.22	5.37	5.88	6.09	6.12	6.56	6.89	7.68	8.17	8.49
Natural Gas (dollars per thousand cubic feet)										
Wellhead Price[14]	6.39	5.52	6.05	6.26	6.29	6.75	7.09	7.90	8.40	8.73
Coal (dollars per ton)										
Minemouth Price[15]	25.82	28.93	29.45	29.75	26.97	27.90	29.13	27.41	29.10	29.85
Coal (dollars per million Btu)										
Minemouth Price[15]	1.27	1.42	1.44	1.46	1.34	1.39	1.45	1.37	1.46	1.50
Average Delivered Price[16]	1.86	1.94	1.99	2.02	1.89	1.99	2.10	1.96	2.08	2.18
Average Electricity Price (cents per kilowatthour)	9.1	8.8	9.0	9.1	9.1	9.4	9.7	10.1	10.4	10.6

Table C1. Total Energy Supply and Disposition Summary (Continued)
(Quadrillion Btu per Year, Unless Otherwise Noted)

Supply, Disposition, and Prices	2007	Projections								
		2010			2020			2030		
		Low Oil Price	Reference	High Oil Price	Low Oil Price	Reference	High Oil Price	Low Oil Price	Reference	High Oil Price
Prices (nominal dollars per unit)										
Petroleum (dollars per barrel)										
Imported Low Sulfur Light Crude Oil Price[13]	72.33	61.54	84.42	95.98	65.49	149.14	237.86	72.62	189.10	289.12
Imported Crude Oil Price[13]	63.83	58.23	81.69	93.06	60.74	144.74	233.45	67.13	180.66	285.22
Natural Gas (dollars per million Btu)										
Price at Henry Hub	6.96	6.38	7.01	7.26	8.99	9.60	10.05	12.58	13.42	13.87
Wellhead Price[14]	6.22	5.64	6.19	6.41	7.95	8.48	8.88	11.11	11.85	12.25
Natural Gas (dollars per thousand cubic feet)										
Wellhead Price[14]	6.39	5.80	6.37	6.59	8.17	8.72	9.13	11.42	12.18	12.60
Coal (dollars per ton)										
Minemouth Price[15]	25.82	30.38	31.02	31.35	35.03	36.04	37.53	39.62	42.20	43.06
Coal (dollars per million Btu)										
Minemouth Price[15]	1.27	1.49	1.52	1.53	1.74	1.80	1.87	1.97	2.11	2.16
Average Delivered Price[16]	1.86	2.04	2.10	2.13	2.45	2.57	2.70	2.83	3.01	3.14
Average Electricity Price (cents per kilowatthour)	9.1	9.3	9.5	9.6	11.8	12.2	12.6	14.6	15.1	15.3

[1]Includes waste coal.
[2]Includes grid-connected electricity from wood and waste; biomass, such as corn, used for liquid fuels production; and non-electric energy demand from wood. Refer to Table A17 for details.
[3]Includes grid-connected electricity from landfill gas; biogenic municipal waste; wind; photovoltaic and solar thermal sources; and non-electric energy from renewable sources, such as active and passive solar systems. Excludes electricity imports using renewable sources and nonmarketed renewable energy. See Table A17 for selected nonmarketed residential and commercial renewable energy.
[4]Includes non-biogenic municipal waste, liquid hydrogen, methanol, and some domestic inputs to refineries.
[5]Includes imports of finished petroleum products, unfinished oils, alcohols, ethers, blending components, and renewable fuels such as ethanol.
[6]Includes coal, coal coke (net), and electricity (net).
[7]Includes crude oil and petroleum products.
[8]Balancing item. Includes unaccounted for supply, losses, gains, and net storage withdrawals.
[9]Includes petroleum-derived fuels and non-petroleum derived fuels, such as ethanol and biodiesel, and coal-based synthetic liquids. Petroleum coke, which is a solid, is included. Also included are natural gas plant liquids, crude oil consumed as a fuel, and liquid hydrogen. Refer to Table A17 for detailed renewable liquid fuels consumption.
[10]Excludes coal converted to coal-based synthetic liquids.
[11]Includes grid-connected electricity from wood and wood waste, non-electric energy from wood, and biofuels heat and coproducts used in the production of liquid fuels, but excludes the energy content of the liquid fuels.
[12]Includes non-biogenic municipal waste and net electricity imports.
[13]Weighted average price delivered to U.S. refiners.
[14]Represents lower 48 onshore and offshore supplies.
[15]Includes reported prices for both open market and captive mines.
[16]Prices weighted by consumption; weighted average excludes residential and commercial prices, and export free-alongside-ship (f.a.s.) prices.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Data for 2007 are model results and may differ slightly from official EIA data reports.
Sources: 2007 natural gas supply values and natural gas wellhead price: EIA, *Natural Gas Monthly*, DOE/EIA-0130(2008/08) (Washington, DC, August 2008). 2007 coal minemouth and delivered coal prices: EIA, *Annual Energy Review 2007*, DOE/EIA-0384(2007) (Washington, DC, June 2008). 2007 petroleum supply values: EIA, *Petroleum Supply Annual 2007,* DOE/EIA-0340(2007)/1 (Washington, DC, July 2008). 2007 low sulfur light crude oil price: EIA, Form EIA-856, "Monthly Foreign Crude Oil Acquisition Report." Other 2007 coal values: *Quarterly Coal Report, October-December 2007*, DOE/EIA-0121(2007/4Q) (Washington, DC, March 2008). Other 2007 values: EIA, *Annual Energy Review 2007*, DOE/EIA-0384(2007) (Washington, DC, June 2008). **Projections:** EIA, AEO2009 National Energy Modeling System runs LP2009.D122308A, AEO2009.D120908A, and HP2009.D121108A.

Table C2. Energy Consumption by Sector and Source
(Quadrillion Btu per Year, Unless Otherwise Noted)

Sector and Source	2007	Projections								
		2010			2020			2030		
		Low Oil Price	Reference	High Oil Price	Low Oil Price	Reference	High Oil Price	Low Oil Price	Reference	High Oil Price
Energy Consumption										
Residential										
Liquefied Petroleum Gases	0.50	0.50	0.49	0.49	0.56	0.49	0.45	0.62	0.52	0.46
Kerosene	0.08	0.08	0.08	0.07	0.08	0.07	0.07	0.08	0.07	0.07
Distillate Fuel Oil	0.78	0.73	0.72	0.71	0.68	0.60	0.54	0.61	0.51	0.46
Liquid Fuels and Other Petroleum Subtotal	1.35	1.31	1.29	1.27	1.32	1.16	1.06	1.31	1.10	0.99
Natural Gas	4.86	4.94	4.92	4.91	5.15	5.10	5.06	5.08	5.07	5.06
Coal	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Renewable Energy[1]	0.43	0.42	0.43	0.44	0.40	0.48	0.55	0.40	0.50	0.57
Electricity	4.75	4.81	4.80	4.79	5.16	5.12	5.07	5.74	5.69	5.65
Delivered Energy	**11.40**	**11.49**	**11.44**	**11.42**	**12.05**	**11.86**	**11.75**	**12.53**	**12.36**	**12.29**
Electricity Related Losses	10.36	10.44	10.44	10.44	10.87	10.81	10.72	11.72	11.69	11.59
Total	**21.76**	**21.93**	**21.88**	**21.86**	**22.92**	**22.67**	**22.46**	**24.25**	**24.05**	**23.88**
Commercial										
Liquefied Petroleum Gases	0.09	0.09	0.09	0.09	0.10	0.10	0.10	0.10	0.10	0.10
Motor Gasoline[2]	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05
Kerosene	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Distillate Fuel Oil	0.41	0.37	0.36	0.35	0.41	0.34	0.30	0.44	0.34	0.30
Residual Fuel Oil	0.08	0.08	0.07	0.07	0.09	0.08	0.08	0.09	0.08	0.08
Liquid Fuels and Other Petroleum Subtotal	0.63	0.60	0.58	0.56	0.66	0.58	0.54	0.70	0.59	0.54
Natural Gas	3.10	3.16	3.14	3.13	3.41	3.34	3.30	3.53	3.54	3.54
Coal	0.07	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06
Renewable Energy[3]	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12
Electricity	4.58	4.76	4.75	4.75	5.65	5.57	5.51	6.36	6.31	6.29
Delivered Energy	**8.50**	**8.72**	**8.66**	**8.64**	**9.90**	**9.69**	**9.54**	**10.77**	**10.62**	**10.56**
Electricity Related Losses	9.99	10.33	10.35	10.35	11.89	11.77	11.65	12.99	12.96	12.89
Total	**18.49**	**19.05**	**19.01**	**18.99**	**21.79**	**21.46**	**21.19**	**23.76**	**23.59**	**23.45**
Industrial[4]										
Liquefied Petroleum Gases	2.35	2.06	2.02	1.99	1.82	1.79	1.76	1.68	1.66	1.66
Motor Gasoline[2]	0.36	0.35	0.34	0.34	0.34	0.34	0.34	0.37	0.36	0.36
Distillate Fuel Oil	1.28	1.18	1.17	1.16	1.21	1.18	1.18	1.29	1.23	1.23
Residual Fuel Oil	0.25	0.16	0.15	0.14	0.22	0.16	0.14	0.32	0.16	0.15
Petrochemical Feedstocks	1.30	1.03	1.01	1.00	1.14	1.13	1.12	1.08	1.05	1.06
Other Petroleum[5]	4.42	4.04	3.74	3.66	4.83	3.72	3.03	5.41	3.84	3.01
Liquid Fuels and Other Petroleum Subtotal	9.96	8.82	8.42	8.29	9.57	8.32	7.57	10.16	8.30	7.46
Natural Gas	6.82	6.64	6.77	6.80	6.17	6.84	7.28	6.06	7.04	7.45
Natural-Gas-to-Liquids Heat and Power	0.00	0.00	0.00	0.00	0.00	0.00	0.12	0.00	0.00	0.49
Lease and Plant Fuel[6]	1.20	1.28	1.27	1.27	1.27	1.33	1.37	1.39	1.47	1.57
Natural Gas Subtotal	8.02	7.92	8.05	8.07	7.44	8.17	8.77	7.45	8.51	9.51
Metallurgical Coal	0.60	0.57	0.55	0.54	0.52	0.49	0.47	0.51	0.48	0.46
Other Industrial Coal	1.21	1.25	1.24	1.23	1.16	1.15	1.14	1.17	1.16	1.15
Coal-to-Liquids Heat and Power	0.00	0.00	0.00	0.00	0.10	0.24	0.26	0.10	0.58	0.65
Net Coal Coke Imports	0.03	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Coal Subtotal	1.83	1.83	1.80	1.79	1.79	1.89	1.88	1.79	2.23	2.27
Biofuels Heat and Coproducts	0.40	0.75	0.75	0.75	1.23	1.23	1.69	1.64	1.66	1.81
Renewable Energy[7]	1.64	1.50	1.48	1.48	1.66	1.64	1.62	1.99	1.96	1.93
Electricity	3.43	3.39	3.34	3.32	3.55	3.48	3.46	3.73	3.67	3.66
Delivered Energy	**25.29**	**24.21**	**23.83**	**23.70**	**25.24**	**24.73**	**24.99**	**26.75**	**26.33**	**26.65**
Electricity Related Losses	7.49	7.37	7.27	7.24	7.46	7.36	7.30	7.61	7.55	7.50
Total	**32.77**	**31.58**	**31.10**	**30.94**	**32.70**	**32.09**	**32.29**	**34.37**	**33.87**	**34.15**

Table C2. Energy Consumption by Sector and Source (Continued)
(Quadrillion Btu per Year, Unless Otherwise Noted)

Sector and Source	2007	Projections								
		2010			2020			2030		
		Low Oil Price	Reference	High Oil Price	Low Oil Price	Reference	High Oil Price	Low Oil Price	Reference	High Oil Price
Transportation										
Liquefied Petroleum Gases	0.02	0.01	0.01	0.01	0.01	0.01	0.01	0.02	0.02	0.01
E85[8]	0.00	0.00	0.00	0.00	0.60	0.85	1.74	0.58	2.18	2.73
Motor Gasoline[2]	17.29	17.21	16.93	16.96	18.07	15.56	13.68	19.09	14.49	12.41
Jet Fuel[9]	3.23	3.04	3.00	2.98	3.51	3.42	3.33	4.23	4.12	3.96
Distillate Fuel Oil[10]	6.48	6.20	6.13	6.10	7.53	7.36	7.26	9.21	9.09	9.00
Residual Fuel Oil	0.95	0.86	0.86	0.86	0.97	0.98	0.98	1.00	1.00	1.01
Liquid Hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Other Petroleum[11]	0.17	0.17	0.17	0.17	0.18	0.18	0.18	0.18	0.18	0.18
Liquid Fuels and Other Petroleum Subtotal	28.14	27.50	27.11	27.09	30.88	28.36	27.18	34.32	31.09	29.31
Pipeline Fuel Natural Gas	0.64	0.65	0.64	0.64	0.66	0.69	0.69	0.71	0.72	0.72
Compressed Natural Gas	0.02	0.03	0.03	0.03	0.06	0.07	0.07	0.07	0.09	0.10
Electricity	0.02	0.02	0.02	0.02	0.03	0.03	0.04	0.04	0.05	0.06
Delivered Energy	**28.82**	**28.20**	**27.81**	**27.78**	**31.62**	**29.15**	**27.98**	**35.14**	**31.94**	**30.19**
Electricity Related Losses	0.05	0.05	0.05	0.05	0.06	0.07	0.07	0.09	0.10	0.12
Total	**28.87**	**28.25**	**27.86**	**27.83**	**31.68**	**29.22**	**28.05**	**35.23**	**32.05**	**30.32**
Delivered Energy Consumption for All Sectors										
Liquefied Petroleum Gases	2.95	2.67	2.61	2.58	2.49	2.39	2.32	2.42	2.29	2.24
E85[8]	0.00	0.00	0.00	0.00	0.60	0.85	1.74	0.58	2.18	2.73
Motor Gasoline[2]	17.70	17.60	17.33	17.35	18.46	15.95	14.08	19.51	14.90	12.82
Jet Fuel[9]	3.23	3.04	3.00	2.98	3.51	3.42	3.33	4.23	4.12	3.96
Kerosene	0.11	0.11	0.10	0.10	0.11	0.10	0.10	0.11	0.10	0.10
Distillate Fuel Oil	8.94	8.49	8.38	8.33	9.84	9.49	9.28	11.55	11.17	10.99
Residual Fuel Oil	1.28	1.11	1.07	1.06	1.29	1.22	1.20	1.41	1.25	1.23
Petrochemical Feedstocks	1.30	1.03	1.01	1.00	1.14	1.13	1.12	1.08	1.05	1.06
Liquid Hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Other Petroleum[12]	4.57	4.19	3.89	3.81	4.99	3.89	3.19	5.58	4.01	3.18
Liquid Fuels and Other Petroleum Subtotal	40.08	38.23	37.40	37.23	42.43	38.42	36.36	46.48	41.07	38.30
Natural Gas	14.79	14.77	14.86	14.88	14.78	15.34	15.72	14.74	15.73	16.16
Natural-Gas-to-Liquids Heat and Power	0.00	0.00	0.00	0.00	0.00	0.00	0.12	0.00	0.00	0.49
Lease and Plant Fuel[6]	1.20	1.28	1.27	1.27	1.27	1.33	1.37	1.39	1.47	1.57
Pipeline Natural Gas	0.64	0.65	0.64	0.64	0.66	0.69	0.69	0.71	0.72	0.72
Natural Gas Subtotal	16.64	16.70	16.78	16.78	16.71	17.36	17.89	16.84	17.92	18.94
Metallurgical Coal	0.60	0.57	0.55	0.54	0.52	0.49	0.47	0.51	0.48	0.46
Other Coal	1.28	1.32	1.31	1.31	1.23	1.22	1.22	1.24	1.23	1.22
Coal-to-Liquids Heat and Power	0.00	0.00	0.00	0.00	0.10	0.24	0.26	0.10	0.58	0.65
Net Coal Coke Imports	0.03	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Coal Subtotal	1.91	1.90	1.87	1.86	1.86	1.97	1.96	1.86	2.30	2.35
Biofuels Heat and Coproducts	0.40	0.75	0.75	0.75	1.23	1.23	1.69	1.64	1.66	1.81
Renewable Energy[13]	2.19	2.04	2.03	2.03	2.19	2.24	2.29	2.51	2.58	2.63
Electricity	12.79	12.99	12.91	12.89	14.39	14.20	14.07	15.86	15.73	15.66
Delivered Energy	**74.01**	**72.61**	**71.74**	**71.54**	**78.81**	**75.42**	**74.25**	**85.19**	**81.26**	**79.69**
Electricity Related Losses	27.88	28.20	28.11	28.08	30.28	30.02	29.74	32.41	32.30	32.11
Total	**101.89**	**100.80**	**99.85**	**99.62**	**109.09**	**105.44**	**104.00**	**117.61**	**113.56**	**111.80**
Electric Power[14]										
Distillate Fuel Oil	0.11	0.11	0.11	0.11	0.13	0.12	0.12	0.14	0.13	0.13
Residual Fuel Oil	0.56	0.39	0.38	0.38	0.65	0.39	0.39	0.86	0.40	0.40
Liquid Fuels and Other Petroleum Subtotal	0.67	0.50	0.49	0.49	0.78	0.51	0.51	1.00	0.53	0.53
Natural Gas	7.06	6.64	6.42	6.31	6.98	6.73	6.29	7.39	7.12	6.78
Steam Coal	20.84	21.02	21.03	21.02	22.07	22.01	21.91	24.12	24.25	24.18
Nuclear Power	8.41	8.45	8.45	8.45	8.89	8.99	9.10	9.14	9.47	9.57
Renewable Energy[15]	3.45	4.37	4.42	4.49	5.78	5.79	5.79	6.41	6.43	6.46
Electricity Imports	0.11	0.08	0.08	0.09	0.04	0.06	0.09	0.09	0.10	0.12
Total[16]	**40.67**	**41.19**	**41.02**	**40.97**	**44.67**	**44.22**	**43.82**	**48.27**	**48.03**	**47.77**

Table C2. Energy Consumption by Sector and Source (Continued)

(Quadrillion Btu per Year, Unless Otherwise Noted)

Sector and Source	2007	Projections								
		2010			2020			2030		
		Low Oil Price	Reference	High Oil Price	Low Oil Price	Reference	High Oil Price	Low Oil Price	Reference	High Oil Price
Total Energy Consumption										
Liquefied Petroleum Gases	2.95	2.67	2.61	2.58	2.49	2.39	2.32	2.42	2.29	2.24
E85[8]	0.00	0.00	0.00	0.00	0.60	0.85	1.74	0.58	2.18	2.73
Motor Gasoline[2]	17.70	17.60	17.33	17.35	18.46	15.95	14.08	19.51	14.90	12.82
Jet Fuel[9]	3.23	3.04	3.00	2.98	3.51	3.42	3.33	4.23	4.12	3.96
Kerosene	0.11	0.11	0.10	0.10	0.11	0.10	0.10	0.11	0.10	0.10
Distillate Fuel Oil	9.05	8.61	8.49	8.44	9.97	9.61	9.41	11.68	11.31	11.12
Residual Fuel Oil	1.84	1.50	1.45	1.44	1.93	1.60	1.59	2.27	1.64	1.63
Petrochemical Feedstocks	1.30	1.03	1.01	1.00	1.14	1.13	1.12	1.08	1.05	1.06
Liquid Hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Other Petroleum[12]	4.57	4.19	3.89	3.81	4.99	3.89	3.19	5.58	4.01	3.18
Liquid Fuels and Other Petroleum Subtotal	40.75	38.73	37.89	37.72	43.21	38.93	36.87	47.48	41.60	38.83
Natural Gas	21.86	21.41	21.29	21.19	21.77	22.07	22.01	22.13	22.86	22.93
Natural-Gas-to-Liquids Heat and Power	0.00	0.00	0.00	0.00	0.00	0.00	0.12	0.00	0.00	0.49
Lease and Plant Fuel[6]	1.20	1.28	1.27	1.27	1.27	1.33	1.37	1.39	1.47	1.57
Pipeline Natural Gas	0.64	0.65	0.64	0.64	0.66	0.69	0.69	0.71	0.72	0.72
Natural Gas Subtotal	23.70	23.34	23.20	23.10	23.70	24.09	24.18	24.23	25.04	25.72
Metallurgical Coal	0.60	0.57	0.55	0.54	0.52	0.49	0.47	0.51	0.48	0.46
Other Coal	22.12	22.34	22.34	22.33	23.30	23.24	23.12	25.37	25.49	25.41
Coal-to-Liquids Heat and Power	0.00	0.00	0.00	0.00	0.10	0.24	0.26	0.10	0.58	0.65
Net Coal Coke Imports	0.03	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Coal Subtotal	22.74	22.92	22.91	22.88	23.93	23.98	23.86	25.99	26.56	26.53
Nuclear Power	8.41	8.45	8.45	8.45	8.89	8.99	9.10	9.14	9.47	9.57
Biofuels Heat and Coproducts	0.40	0.75	0.75	0.75	1.23	1.23	1.69	1.64	1.66	1.81
Renewable Energy[17]	5.65	6.40	6.45	6.52	7.97	8.03	8.08	8.92	9.01	9.09
Electricity Imports	0.11	0.08	0.08	0.09	0.04	0.06	0.09	0.09	0.10	0.12
Total	**101.89**	**100.80**	**99.85**	**99.62**	**109.09**	**105.44**	**104.00**	**117.61**	**113.56**	**111.80**
Energy Use and Related Statistics										
Delivered Energy Use	74.01	72.61	71.74	71.54	78.81	75.42	74.25	85.19	81.26	79.69
Total Energy Use	101.89	100.80	99.85	99.62	109.09	105.44	104.00	117.61	113.56	111.80
Ethanol Consumed in Motor Gasoline and E85	0.56	1.10	1.08	1.09	1.66	1.66	2.14	1.73	2.47	2.71
Population (millions)	302.41	311.37	311.37	311.37	342.61	342.61	342.61	375.12	375.12	375.12
Gross Domestic Product (billion 2000 dollars)	11524	11842	11779	11751	15486	15524	15572	20044	20114	20293
Carbon Dioxide Emissions (million metric tons)	5990.8	5865.7	5801.4	5781.7	6262.4	5982.3	5784.8	6792.3	6414.4	6202.6

[1]Includes wood used for residential heating. See Table A4 and/or Table A17 for estimates of nonmarketed renewable energy consumption for geothermal heat pumps, solar thermal hot water heating, and solar photovoltaic electricity generation.
[2]Includes ethanol (blends of 10 percent or less) and ethers blended into gasoline.
[3]Excludes ethanol. Includes commercial sector consumption of wood and wood waste, landfill gas, municipal waste, and other biomass for combined heat and power. See Table A5 and/or Table A17 for estimates of nonmarketed renewable energy consumption for solar thermal hot water heating and solar photovoltaic electricity generation.
[4]Includes energy for combined heat and power plants, except those whose primary business is to sell electricity, or electricity and heat, to the public.
[5]Includes petroleum coke, asphalt, road oil, lubricants, still gas, and miscellaneous petroleum products.
[6]Represents natural gas used in well, field, and lease operations, and in natural gas processing plant machinery.
[7]Includes consumption of energy produced from hydroelectric, wood and wood waste, municipal waste, and other biomass sources. Excludes ethanol blends (10 percent or less) in motor gasoline.
[8]E85 refers to a blend of 85 percent ethanol (renewable) and 15 percent motor gasoline (nonrenewable). To address cold starting issues, the percentage of ethanol varies seasonally. The annual average ethanol content of 74 percent is used for this forecast.
[9]Includes only kerosene type.
[10]Diesel fuel for on- and off- road use.
[11]Includes aviation gasoline and lubricants.
[12]Includes unfinished oils, natural gasoline, motor gasoline blending components, aviation gasoline, lubricants, still gas, asphalt, road oil, petroleum coke, and miscellaneous petroleum products.
[13]Includes electricity generated for sale to the grid and for own use from renewable sources, and non-electric energy from renewable sources. Excludes ethanol and nonmarketed renewable energy consumption for geothermal heat pumps, buildings photovoltaic systems, and solar thermal hot water heaters.
[14]Includes consumption of energy by electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public. Includes small power producers and exempt wholesale generators.
[15]Includes conventional hydroelectric, geothermal, wood and wood waste, biogenic municipal waste, other biomass, wind, photovoltaic, and solar thermal sources. Excludes net electricity imports.
[16]Includes non-biogenic municipal waste not included above.
[17]Includes conventional hydroelectric, geothermal, wood and wood waste, biogenic municipal waste, other biomass, wind, photovoltaic, and solar thermal sources. Excludes ethanol, net electricity imports, and nonmarketed renewable energy consumption for geothermal heat pumps, buildings photovoltaic systems, and solar thermal hot water heaters.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Data for 2007 are model results and may differ slightly from official EIA data reports.
Sources: 2007 consumption based on: Energy Information Administration (EIA), *Annual Energy Review 2007*, DOE/EIA-0384(2007) (Washington, DC, June 2008). 2007 population and gross domestic product: IHS Global Insight Industry and Employment models, November 2008. 2007 carbon dioxide emissions: EIA, *Emissions of Greenhouse Gases in the United States 2007,* DOE/EIA-0573(2007) (Washington, DC, December 2008). **Projections:** EIA, AEO2009 National Energy Modeling System runs LP2009.D122308A, AEO2009.D120908A, and HP2009.D121108A.

Table C3. Energy Prices by Sector and Source
(2007 Dollars per Million Btu, Unless Otherwise Noted)

Sector and Source	2007	Projections								
		2010			2020			2030		
		Low Oil Price	Reference	High Oil Price	Low Oil Price	Reference	High Oil Price	Low Oil Price	Reference	High Oil Price
Residential										
Liquefied Petroleum Gases	24.98	21.82	25.86	27.93	20.47	32.88	47.65	20.53	35.11	50.76
Distillate Fuel Oil	19.66	15.29	18.69	20.69	13.48	24.10	36.51	13.39	26.67	39.19
Natural Gas	12.69	11.53	12.09	12.33	11.93	12.50	12.91	13.85	14.31	14.61
Electricity	31.19	30.40	30.89	31.14	31.68	32.72	33.78	34.81	35.84	36.49
Commercial										
Liquefied Petroleum Gases	23.04	18.65	22.69	24.75	17.25	29.60	44.35	17.27	31.77	47.40
Distillate Fuel Oil	16.05	12.74	16.15	18.14	11.59	22.11	34.23	11.67	24.69	36.99
Residual Fuel Oil	10.21	7.04	10.97	12.82	5.86	16.68	27.02	5.99	17.98	29.99
Natural Gas	10.99	9.99	10.55	10.78	10.57	11.13	11.53	12.46	12.96	13.24
Electricity	28.07	26.81	27.29	27.53	26.92	28.15	29.30	29.99	31.01	31.70
Industrial[1]										
Liquefied Petroleum Gases	23.38	17.79	21.84	23.92	16.39	28.78	43.57	16.51	30.99	46.62
Distillate Fuel Oil	16.82	12.62	16.01	17.99	12.16	22.56	34.48	12.47	25.19	37.30
Residual Fuel Oil	10.49	11.72	15.38	17.26	10.68	20.94	32.04	11.10	22.73	34.48
Natural Gas[2]	7.52	6.39	6.91	7.12	7.05	7.48	7.86	8.73	9.07	9.42
Metallurgical Coal	3.61	4.34	4.37	4.39	4.32	4.40	4.49	4.29	4.41	4.49
Other Industrial Coal	2.43	2.47	2.54	2.57	2.43	2.53	2.63	2.52	2.67	2.75
Coal to Liquids	- -	- -	- -	- -	1.10	1.23	1.29	1.02	1.36	1.47
Electricity	18.63	18.36	18.72	18.90	18.45	19.06	19.70	21.05	21.59	21.76
Transportation										
Liquefied Petroleum Gases[3]	25.01	21.65	25.67	27.74	20.26	32.62	47.38	20.27	34.77	50.41
E85[4]	26.67	19.51	25.47	27.69	16.21	29.30	36.17	16.61	30.10	38.91
Motor Gasoline[5]	22.98	18.29	23.47	25.44	16.73	29.75	41.68	16.82	32.10	45.23
Jet Fuel[6]	16.10	12.60	16.03	18.12	11.05	22.15	33.99	11.03	24.63	36.94
Diesel Fuel (distillate fuel oil)[7]	20.92	16.62	20.05	22.03	15.67	26.04	37.95	15.91	28.59	40.68
Residual Fuel Oil	9.35	9.08	12.10	14.00	7.56	17.46	29.23	7.29	19.65	32.46
Natural Gas[8]	15.46	14.36	14.90	15.12	14.33	14.90	15.30	15.68	16.24	16.57
Electricity	30.64	29.96	30.34	30.53	29.27	29.48	30.56	32.61	34.15	34.98
Electric Power[9]										
Distillate Fuel Oil	14.77	11.71	15.09	17.08	9.89	20.45	32.76	9.84	23.11	35.54
Residual Fuel Oil	8.38	9.76	13.21	15.15	7.38	18.55	30.13	6.88	20.67	33.04
Natural Gas	7.02	6.09	6.59	6.79	6.69	7.15	7.47	8.22	8.70	9.01
Steam Coal	1.78	1.84	1.89	1.92	1.81	1.92	2.03	1.89	2.04	2.14
Average Price to All Users[10]										
Liquefied Petroleum Gases	18.53	17.19	20.96	22.90	16.16	27.56	41.23	16.38	29.77	44.24
E85[4]	26.67	19.51	25.47	27.69	16.21	29.30	36.17	16.61	30.10	38.91
Motor Gasoline[5]	22.82	18.29	23.47	25.44	16.73	29.75	41.68	16.82	32.10	45.23
Jet Fuel	16.10	12.60	16.03	18.12	11.05	22.15	33.99	11.03	24.63	36.94
Distillate Fuel Oil	19.94	15.58	18.98	20.96	14.85	25.28	37.24	15.17	27.94	40.07
Residual Fuel Oil	9.25	9.43	12.66	14.57	7.79	18.03	29.60	7.62	20.12	32.66
Natural Gas	9.01	8.02	8.56	8.78	8.66	9.11	9.48	10.35	10.75	11.06
Metallurgical Coal	3.61	4.34	4.37	4.39	4.32	4.40	4.49	4.29	4.41	4.49
Other Coal	1.82	1.88	1.93	1.96	1.84	1.95	2.07	1.92	2.07	2.17
Coal to Liquids	- -	- -	- -	- -	1.10	1.23	1.29	1.02	1.36	1.47
Electricity	26.70	25.94	26.42	26.65	26.54	27.57	28.56	29.64	30.56	31.12
Non-Renewable Energy Expenditures by Sector (billion 2007 dollars)										
Residential	238.38	226.46	235.27	239.70	246.77	263.30	280.47	291.88	310.03	324.47
Commercial	173.09	167.42	172.88	175.53	196.17	207.76	218.92	243.25	256.75	267.35
Industrial	226.84	183.13	204.25	215.22	180.75	242.68	314.44	203.51	276.26	349.17
Transportation	596.75	465.56	580.97	634.28	469.76	752.82	995.15	525.91	853.25	1116.08
Total Non-Renewable Expenditures	1235.06	1042.56	1193.36	1264.74	1093.46	1466.55	1808.98	1264.54	1696.29	2057.07
Transportation Renewable Expenditures	0.04	0.06	0.07	0.07	9.78	24.83	63.06	9.71	65.71	106.39
Total Expenditures	**1235.10**	**1042.62**	**1193.43**	**1264.81**	**1103.25**	**1491.38**	**1872.04**	**1274.25**	**1762.00**	**2163.46**

Table C3. Energy Prices by Sector and Source (Continued)
(Nominal Dollars per Million Btu, Unless Otherwise Noted)

Sector and Source	2007	Projections								
		2010			2020			2030		
		Low Oil Price	Reference	High Oil Price	Low Oil Price	Reference	High Oil Price	Low Oil Price	Reference	High Oil Price
Residential										
Liquefied Petroleum Gases	24.98	22.91	27.24	29.43	26.58	42.47	61.39	29.68	50.90	73.23
Distillate Fuel Oil	19.66	16.06	19.68	21.81	17.50	31.14	47.04	19.35	38.67	56.54
Natural Gas	12.69	12.10	12.74	12.99	15.49	16.14	16.64	20.02	20.75	21.08
Electricity	31.19	31.92	32.53	32.81	41.13	42.26	43.52	50.33	51.96	52.65
Commercial										
Liquefied Petroleum Gases	23.04	19.58	23.89	26.08	22.40	38.24	57.14	24.96	46.06	68.38
Distillate Fuel Oil	16.05	13.38	17.01	19.11	15.06	28.56	44.10	16.88	35.80	53.36
Residual Fuel Oil	10.21	7.40	11.55	13.51	7.61	21.55	34.81	8.66	26.07	43.26
Natural Gas	10.99	10.49	11.11	11.36	13.73	14.37	14.85	18.01	18.78	19.10
Electricity	28.07	28.15	28.74	29.01	34.96	36.37	37.75	43.36	44.96	45.73
Industrial[1]										
Liquefied Petroleum Gases	23.38	18.68	23.00	25.20	21.28	37.17	56.13	23.86	44.93	67.25
Distillate Fuel Oil	16.82	13.25	16.86	18.96	15.80	29.14	44.43	18.03	36.52	53.81
Residual Fuel Oil	10.49	12.30	16.20	18.19	13.87	27.05	41.29	16.05	32.95	49.74
Natural Gas[2]	7.52	6.71	7.27	7.51	9.15	9.66	10.12	12.62	13.16	13.59
Metallurgical Coal	3.61	4.56	4.60	4.62	5.61	5.69	5.78	6.20	6.40	6.48
Other Industrial Coal	2.43	2.60	2.67	2.71	3.15	3.27	3.39	3.64	3.88	3.97
Coal to Liquids	- -	- -	- -	- -	1.42	1.59	1.67	1.47	1.98	2.11
Electricity	18.63	19.28	19.72	19.92	23.97	24.63	25.38	30.43	31.30	31.39
Transportation										
Liquefied Petroleum Gases[3]	25.01	22.73	27.04	29.23	26.31	42.13	61.05	29.30	50.41	72.71
E85[4]	26.67	20.49	26.83	29.17	21.05	37.85	46.60	24.01	43.63	56.13
Motor Gasoline[5]	22.98	19.21	24.72	26.81	21.72	38.43	53.71	24.32	46.54	65.24
Jet Fuel[6]	16.10	13.23	16.89	19.09	14.35	28.62	43.79	15.94	35.70	53.29
Diesel Fuel (distillate fuel oil)[7]	20.92	17.45	21.12	23.21	20.35	33.63	48.90	23.00	41.44	58.69
Residual Fuel Oil	9.35	9.54	12.74	14.75	9.82	22.56	37.67	10.53	28.49	46.82
Natural Gas[8]	15.46	15.08	15.69	15.94	18.62	19.24	19.72	22.67	23.55	23.90
Electricity	30.64	31.46	31.95	32.18	38.01	38.09	39.37	47.14	49.51	50.47
Electric Power[9]										
Distillate Fuel Oil	14.77	12.29	15.89	18.00	12.84	26.42	42.20	14.22	33.51	51.27
Residual Fuel Oil	8.38	10.25	13.91	15.97	9.59	23.97	38.82	9.95	29.97	47.66
Natural Gas	7.02	6.39	6.94	7.15	8.69	9.24	9.63	11.88	12.61	12.99
Steam Coal	1.78	1.94	1.99	2.02	2.34	2.48	2.62	2.73	2.95	3.09

Table C3. Energy Prices by Sector and Source (Continued)
(Nominal Dollars per Million Btu, Unless Otherwise Noted)

Sector and Source	2007	Projections								
		2010			2020			2030		
		Low Oil Price	Reference	High Oil Price	Low Oil Price	Reference	High Oil Price	Low Oil Price	Reference	High Oil Price
Average Price to All Users[10]										
Liquefied Petroleum Gases	18.53	18.05	22.07	24.13	20.99	35.61	53.12	23.68	43.16	63.81
E85[4]	26.67	20.49	26.83	29.17	21.05	37.85	46.60	24.01	43.63	56.13
Motor Gasoline[5]	22.82	19.20	24.71	26.80	21.72	38.43	53.70	24.32	46.54	65.24
Jet Fuel	16.10	13.23	16.89	19.09	14.35	28.62	43.79	15.94	35.70	53.29
Distillate Fuel Oil	19.94	16.36	19.99	22.09	19.29	32.65	47.99	21.93	40.51	57.81
Residual Fuel Oil	9.25	9.90	13.34	15.35	10.11	23.29	38.14	11.02	29.16	47.12
Natural Gas	9.01	8.42	9.01	9.25	11.25	11.77	12.22	14.96	15.58	15.96
Metallurgical Coal	3.61	4.56	4.60	4.62	5.61	5.69	5.78	6.20	6.40	6.48
Other Coal	1.82	1.98	2.04	2.07	2.39	2.52	2.66	2.78	3.00	3.13
Coal to Liquids	- -	- -	- -	- -	1.42	1.59	1.67	1.47	1.98	2.11
Electricity	26.70	27.23	27.82	28.08	34.47	35.62	36.80	42.85	44.31	44.90
Non-Renewable Energy Expenditures by Sector (billion nominal dollars)										
Residential	238.38	237.79	247.78	252.58	320.47	340.12	361.38	421.94	449.49	468.06
Commercial	173.09	175.79	182.07	184.97	254.76	268.38	282.07	351.64	372.25	385.67
Industrial	226.84	192.29	215.12	226.79	234.72	313.49	405.15	294.19	400.54	503.70
Transportation	596.75	488.85	611.87	668.38	610.05	972.48	1282.23	760.26	1237.08	1610.01
Total Non-Renewable Expenditures	1235.06	1094.72	1256.84	1332.72	1419.99	1894.47	2330.83	1828.02	2459.36	2967.44
Transportation Renewable Expenditures	0.04	0.06	0.07	0.07	12.71	32.08	81.25	14.04	95.27	153.48
Total Expenditures	**1235.10**	**1094.78**	**1256.91**	**1332.79**	**1432.70**	**1926.55**	**2412.08**	**1842.06**	**2554.63**	**3120.92**

[1]Includes energy for combined heat and power plants, except those whose primary business is to sell electricity, or electricity and heat, to the public.
[2]Excludes use for lease and plant fuel.
[3]Includes Federal and State taxes while excluding county and local taxes.
[4]E85 refers to a blend of 85 percent ethanol (renewable) and 15 percent motor gasoline (nonrenewable). To address cold starting issues, the percentage of ethanol varies seasonally. The annual average ethanol content of 74 percent is used for this forecast.
[5]Sales weighted-average price for all grades. Includes Federal, State and local taxes.
[6]Kerosene-type jet fuel. Includes Federal and State taxes while excluding county and local taxes.
[7]Diesel fuel for on-road use. Includes Federal and State taxes while excluding county and local taxes.
[8]Compressed natural gas used as a vehicle fuel. Includes estimated motor vehicle fuel taxes and estimated dispensing costs or charges.
[9]Includes electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public.
[10]Weighted averages of end-use fuel prices are derived from the prices shown in each sector and the corresponding sectoral consumption.
Btu = British thermal unit.
- - = Not applicable.
Note: Data for 2007 are model results and may differ slightly from official EIA data reports.
Sources: 2007 prices for motor gasoline, distillate fuel oil, and jet fuel are based on prices in the Energy Information Administration (EIA), *Petroleum Marketing Annual 2007*, DOE/EIA-0487(2007) (Washington, DC, August 2008). 2007 residential and commercial natural gas delivered prices: EIA, *Natural Gas Monthly*, DOE/EIA-0130(2008/08) (Washington, DC, August 2008). 2007 industrial natural gas delivered prices are estimated based on: EIA, *Manufacturing Energy Consumption Survey 1994* and industrial and wellhead prices from the *Natural Gas Annual 2006*, DOE/EIA-0131(2006) (Washington, DC, October 2007) and the *Natural Gas Monthly*, DOE/EIA-0130(2008/08) (Washington, DC, August 2008). 2007 transportation sector natural gas delivered prices are model results. 2007 electric power sector natural gas prices: EIA, *Electric Power Monthly*, DOE/EIA-0226, April 2007 and April 2008, Table 4.13.B. 2007 coal prices based on: EIA, *Quarterly Coal Report, October-December 2007*, DOE/EIA-0121(2007/4Q) (Washington, DC, March 2008) and EIA, AEO2009 National Energy Modeling System run AEO2009.D120908A. 2007 electricity prices: EIA, *Annual Energy Review 2007*, DOE/EIA-0384(2007) (Washington, DC, June 2008). 2007 E85 prices derived from monthly prices in the Clean Cities Alternative Fuel Price Report.
Projections: EIA, AEO2009 National Energy Modeling System runs LP2009.D122308A, AEO2009.D120908A, and HP2009.D121108A.

Table C4. Liquid Fuels Supply and Disposition
(Million Barrels per Day, Unless Otherwise Noted)

Supply and Disposition	2007	2010 Low Oil Price	2010 Reference	2010 High Oil Price	2020 Low Oil Price	2020 Reference	2020 High Oil Price	2030 Low Oil Price	2030 Reference	2030 High Oil Price
Crude Oil										
Domestic Crude Production[1]	5.07	5.62	5.62	5.62	5.35	6.48	7.16	5.36	7.37	8.47
Alaska	0.72	0.69	0.69	0.69	0.41	0.72	0.74	0.26	0.57	0.59
Lower 48 States	4.35	4.93	4.93	4.93	4.95	5.76	6.42	5.10	6.80	7.88
Net Imports	10.00	8.23	8.10	8.02	9.81	7.29	5.44	11.41	6.95	4.30
Gross Imports	10.03	8.26	8.13	8.05	9.84	7.33	5.47	11.44	6.99	4.35
Exports	0.03	0.03	0.03	0.03	0.03	0.03	0.04	0.03	0.04	0.05
Other Crude Supply[2]	0.09	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total Crude Supply	**15.16**	**13.85**	**13.72**	**13.64**	**15.16**	**13.77**	**12.59**	**16.77**	**14.32**	**12.77**
Other Supply										
Natural Gas Plant Liquids	1.78	1.92	1.91	1.90	1.89	1.91	1.92	1.79	1.92	1.97
Net Product Imports	2.09	1.87	1.66	1.63	2.20	1.49	1.28	2.32	1.40	1.14
Gross Refined Product Imports[3]	1.94	1.82	1.64	1.62	2.01	1.60	1.46	2.03	1.54	1.31
Unfinished Oil Imports	0.72	0.59	0.58	0.57	0.75	0.58	0.44	0.95	0.65	0.46
Blending Component Imports	0.75	0.64	0.62	0.62	0.73	0.66	0.71	0.80	0.69	0.74
Exports	1.32	1.18	1.18	1.17	1.29	1.35	1.33	1.46	1.47	1.37
Refinery Processing Gain[4]	1.00	1.01	0.97	0.98	1.02	0.93	0.88	1.06	0.86	0.72
Other Inputs	0.74	1.23	1.22	1.25	1.84	1.98	2.60	2.20	3.08	3.76
Ethanol	0.45	0.85	0.84	0.84	1.29	1.28	1.66	1.34	1.91	2.10
Domestic Production	0.43	0.85	0.84	0.84	1.23	1.24	1.56	1.35	1.43	1.48
Net Imports	0.02	-0.00	-0.00	0.00	0.06	0.04	0.10	-0.00	0.49	0.62
Biodiesel	0.03	0.06	0.06	0.07	0.06	0.10	0.13	0.07	0.13	0.17
Domestic Production	0.03	0.06	0.06	0.07	0.06	0.10	0.13	0.07	0.13	0.17
Net Imports	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Liquids from Gas	0.00	0.00	0.00	0.00	0.00	0.00	0.09	0.00	0.00	0.38
Liquids from Coal	0.00	0.00	0.00	0.00	0.04	0.10	0.11	0.04	0.26	0.29
Liquids from Biomass	0.00	0.00	0.00	0.00	0.04	0.07	0.10	0.29	0.33	0.34
Other[5]	0.26	0.32	0.32	0.34	0.41	0.42	0.51	0.45	0.45	0.49
Total Primary Supply[6]	**20.77**	**19.88**	**19.48**	**19.41**	**22.11**	**20.08**	**19.28**	**24.13**	**21.59**	**20.36**
Liquid Fuels Consumption										
by Fuel										
Liquefied Petroleum Gases	2.09	2.04	1.99	1.97	1.90	1.82	1.77	1.84	1.74	1.71
E85[7]	0.00	0.00	0.00	0.00	0.42	0.58	1.20	0.40	1.50	1.88
Motor Gasoline[8]	9.29	9.49	9.34	9.35	9.95	8.60	7.59	10.52	8.04	6.92
Jet Fuel[9]	1.62	1.47	1.45	1.44	1.70	1.65	1.61	2.04	1.99	1.91
Distillate Fuel Oil[10]	4.20	4.14	4.08	4.06	4.79	4.62	4.52	5.61	5.42	5.33
Diesel	3.47	3.51	3.47	3.45	4.17	4.06	4.00	5.01	4.91	4.85
Residual Fuel Oil	0.72	0.65	0.63	0.63	0.84	0.70	0.69	0.99	0.72	0.71
Other[11]	2.74	2.33	2.19	2.15	2.73	2.24	1.93	2.96	2.25	1.89
by Sector										
Residential and Commercial	1.11	1.07	1.05	1.04	1.13	0.99	0.92	1.16	0.97	0.89
Industrial[12]	5.26	4.65	4.46	4.39	4.90	4.34	4.00	5.12	4.28	3.92
Transportation	14.25	14.16	13.96	13.95	15.96	14.65	14.17	17.67	16.18	15.32
Electric Power[13]	0.30	0.22	0.22	0.22	0.34	0.23	0.23	0.44	0.23	0.23
Total	**20.65**	**20.11**	**19.69**	**19.60**	**22.33**	**20.21**	**19.31**	**24.37**	**21.67**	**20.35**
Discrepancy[14]	**0.12**	**-0.23**	**-0.20**	**-0.19**	**-0.22**	**-0.13**	**-0.02**	**-0.24**	**-0.08**	**0.01**

Table C4. Liquid Fuels Supply and Disposition (Continued)
(Million Barrels per Day, Unless Otherwise Noted)

Supply and Disposition	2007	Projections								
		2010			2020			2030		
		Low Oil Price	Reference	High Oil Price	Low Oil Price	Reference	High Oil Price	Low Oil Price	Reference	High Oil Price
Domestic Refinery Distillation Capacity[15]	17.4	18.0	18.0	18.0	18.7	18.2	18.2	19.1	18.4	18.3
Capacity Utilization Rate (percent)[16]	89.0	78.5	77.8	77.3	82.6	77.1	70.5	89.7	79.2	71.3
Net Import Share of Product Supplied (percent)	58.3	50.8	50.1	49.8	54.6	44.0	35.4	56.9	40.9	29.8
Net Expenditures for Imported Crude Oil and Petroleum Products (billion 2007 dollars)	280.13	194.37	261.60	294.55	196.02	344.32	425.05	220.00	376.65	387.94

[1]Includes lease condensate.
[2]Strategic petroleum reserve stock additions plus unaccounted for crude oil and crude stock withdrawals minus crude product supplied.
[3]Includes other hydrocarbons and alcohols.
[4]The volumetric amount by which total output is greater than input due to the processing of crude oil into products which, in total, have a lower specific gravity than the crude oil processed.
[5]Includes petroleum product stock withdrawals; and domestic sources of other blending components, other hydrocarbons, ethers, and renewable feedstocks for the on-site production of diesel and gasoline.
[6]Total crude supply plus natural gas plant liquids, other inputs, refinery processing gain, and net product imports.
[7]E85 refers to a blend of 85 percent ethanol (renewable) and 15 percent motor gasoline (nonrenewable). To address cold starting issues, the percentage of ethanol varies seasonally. The annual average ethanol content of 74 percent is used for this forecast.
[8]Includes ethanol and ethers blended into gasoline.
[9]Includes only kerosene type.
[10]Includes distillate fuel oil and kerosene from petroleum and biomass feedstocks.
[11]Includes aviation gasoline, petrochemical feedstocks, lubricants, waxes, asphalt, road oil, still gas, special naphthas, petroleum coke, crude oil product supplied, methanol, liquid hydrogen,and miscellaneous petroleum products.
[12]Includes consumption for combined heat and power, which produces electricity and other useful thermal energy.
[13]Includes consumption of energy by electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public. Includes small power producers and exempt wholesale generators.
[14]Balancing item. Includes unaccounted for supply, losses, and gains.
[15]End-of-year operable capacity.
[16]Rate is calculated by dividing the gross annual input to atmospheric crude oil distillation units by their operable refining capacity in barrels per calendar day.
Note: Totals may not equal sum of components due to independent rounding. Data for 2007 are model results and may differ slightly from official EIA data reports.
Sources: 2007 petroleum product supplied based on: Energy Information Administration (EIA), *Annual Energy Review 2007*, DOE/EIA-0384(2007) (Washington, DC, June 2008). Other 2007 data: EIA, *Petroleum Supply Annual 2007,* DOE/EIA-0340(2007)/1 (Washington, DC, July 2008). **Projections:** EIA, AEO2009 National Energy Modeling System runs LP2009.D122308A, AEO2009.D120908A, and HP2009.D121108A.

Table C5. Petroleum Product Prices
(2007 Cents per Gallon, Unless Otherwise Noted)

Sector and Fuel	2007	Projections								
		2010			2020			2030		
		Low Oil Price	Reference	High Oil Price	Low Oil Price	Reference	High Oil Price	Low Oil Price	Reference	High Oil Price
Crude Oil Prices (2007 dollars per barrel)										
Imported Low Sulfur Light Crude Oil[1]	72.33	58.61	80.16	91.08	50.43	115.45	184.60	50.23	130.43	200.42
Imported Crude Oil[1]	63.83	55.45	77.56	88.31	46.77	112.05	181.18	46.44	124.60	197.72
Delivered Sector Product Prices										
Residential										
Liquefied Petroleum Gases	213.6	186.6	221.1	238.8	175.0	281.1	407.4	175.6	300.2	434.0
Distillate Fuel Oil	272.7	212.1	259.2	287.0	186.9	334.3	506.4	185.7	369.9	543.6
Commercial										
Distillate Fuel Oil	221.7	175.8	222.8	250.2	159.8	304.9	471.9	161.0	340.4	510.0
Residual Fuel Oil	152.9	105.4	164.2	192.0	87.7	249.7	404.5	89.7	269.1	448.9
Residual Fuel Oil (2007 dollars per barrel)	64.22	44.28	68.96	80.62	36.85	104.88	169.87	37.66	113.04	188.52
Industrial[2]										
Liquefied Petroleum Gases	199.9	152.1	186.7	204.5	140.1	246.0	372.5	141.1	265.0	398.6
Distillate Fuel Oil	232.3	173.5	220.2	247.4	167.0	309.6	473.4	171.3	345.8	512.1
Residual Fuel Oil	157.1	175.4	230.2	258.4	159.9	313.4	479.6	166.2	340.2	516.2
Residual Fuel Oil (2007 dollars per barrel)	65.98	73.66	96.70	108.53	67.14	131.64	201.45	69.80	142.89	216.79
Transportation										
Liquefied Petroleum Gases	213.8	185.1	219.5	237.1	173.2	278.9	405.1	173.3	297.3	431.0
Ethanol (E85)[3]	253.0	185.1	241.7	262.7	153.8	278.0	343.2	157.6	285.5	369.1
Ethanol Wholesale Price	212.4	163.8	192.8	196.4	195.9	201.1	219.3	146.7	193.8	202.3
Motor Gasoline[4]	282.2	221.3	283.9	307.8	202.4	359.9	504.3	203.6	388.4	547.2
Jet Fuel[5]	217.3	170.1	216.5	244.6	149.2	299.1	458.8	148.9	332.4	498.7
Diesel Fuel (distillate fuel oil)[6]	287.0	227.8	274.9	302.0	214.7	356.8	520.1	218.0	391.7	557.5
Residual Fuel Oil	140.0	135.9	181.1	209.5	113.2	261.4	437.6	109.1	294.1	485.8
Residual Fuel Oil (2007 dollars per barrel)	58.80	57.09	76.07	88.01	47.54	109.80	183.79	45.81	123.54	204.05
Electric Power[7]										
Distillate Fuel Oil	204.9	162.4	209.2	236.9	137.1	283.6	454.3	136.4	320.5	492.9
Residual Fuel Oil	125.4	146.1	197.7	226.8	110.5	277.7	451.0	103.0	309.5	494.5
Residual Fuel Oil (2007 dollars per barrel)	52.67	61.35	83.03	95.25	46.43	116.64	189.44	43.27	129.98	207.70
Refined Petroleum Product Prices[8]										
Liquefied Petroleum Gases	158.5	147.0	179.2	195.8	138.2	235.7	352.5	140.1	254.5	378.2
Motor Gasoline[4]	280.2	221.3	283.9	307.8	202.4	359.9	504.3	203.5	388.4	547.2
Jet Fuel[5]	217.3	170.1	216.5	244.6	149.2	299.1	458.8	148.9	332.4	498.7
Distillate Fuel Oil	274.5	214.1	260.9	288.1	203.8	346.8	511.0	208.1	383.2	549.7
Residual Fuel Oil	138.4	141.2	189.6	218.1	116.5	269.8	443.0	114.1	301.1	488.9
Residual Fuel Oil (2007 dollars per barrel)	58.15	59.30	79.62	91.58	48.95	113.34	186.08	47.93	126.47	205.34
Average	**249.1**	**201.7**	**254.9**	**279.3**	**185.6**	**331.1**	**479.2**	**187.3**	**361.4**	**519.4**

Table C5. Petroleum Product Prices (Continued)
(Nominal Cents per Gallon, Unless Otherwise Noted)

Sector and Fuel	2007	Projections								
		2010			2020			2030		
		Low Oil Price	Reference	High Oil Price	Low Oil Price	Reference	High Oil Price	Low Oil Price	Reference	High Oil Price
Crude Oil Prices (nominal dollars per barrel)										
Imported Low Sulfur Light Crude Oil[1]	72.33	61.54	84.42	95.98	65.49	149.14	237.86	72.62	189.10	289.12
Imported Crude Oil[1]	63.83	58.23	81.69	93.06	60.74	144.74	233.45	67.13	180.66	285.22
Delivered Sector Product Prices										
Residential										
Liquefied Petroleum Gases	213.6	195.9	232.9	251.6	227.3	363.1	524.9	253.8	435.2	626.1
Distillate Fuel Oil	272.7	222.7	273.0	302.4	242.7	431.8	652.4	268.4	536.3	784.2
Commercial										
Distillate Fuel Oil	221.7	184.6	234.6	263.7	207.6	393.8	608.1	232.7	493.5	735.7
Residual Fuel Oil	152.9	110.7	172.9	202.3	113.9	322.6	521.1	129.6	390.2	647.5
Industrial[2]										
Liquefied Petroleum Gases	199.9	159.7	196.6	215.5	182.0	317.8	479.9	204.0	384.2	575.0
Distillate Fuel Oil	232.3	182.2	231.9	260.7	216.8	400.0	609.9	247.6	501.4	738.7
Residual Fuel Oil	157.1	184.2	242.5	272.3	207.6	404.9	618.0	240.2	493.3	744.6
Transportation										
Liquefied Petroleum Gases	213.8	194.4	231.2	249.9	224.9	360.3	522.0	250.5	431.0	621.7
Ethanol (E85)[3]	253.0	194.4	254.5	276.8	199.7	359.1	442.1	227.8	414.0	532.5
Ethanol Wholesale Price	212.4	171.9	203.1	207.0	254.4	259.8	282.5	212.1	280.9	291.8
Motor Gasoline[4]	282.2	232.4	299.0	324.3	262.8	464.9	649.8	294.3	563.1	789.4
Jet Fuel[5]	217.3	178.6	228.0	257.7	193.7	386.4	591.2	215.2	482.0	719.5
Diesel Fuel (distillate fuel oil)[6]	287.0	239.2	289.6	318.2	278.8	460.9	670.1	315.2	567.9	804.2
Residual Fuel Oil	140.0	142.7	190.8	220.8	147.0	337.7	563.8	157.7	426.5	700.8
Electric Power[7]										
Distillate Fuel Oil	204.9	170.5	220.4	249.7	178.1	366.4	585.3	197.2	464.7	711.1
Residual Fuel Oil	125.4	153.4	208.2	239.0	143.6	358.8	581.2	148.9	448.7	713.4
Refined Petroleum Product Prices[8]										
Liquefied Petroleum Gases	158.5	154.3	188.7	206.3	179.4	304.5	454.2	202.5	369.1	545.6
Motor Gasoline[4]	280.2	232.3	299.0	324.3	262.8	464.9	649.8	294.2	563.1	789.4
Jet Fuel[5]	217.3	178.6	228.0	257.7	193.7	386.4	591.2	215.2	482.0	719.5
Distillate Fuel Oil	274.5	224.8	274.7	303.5	264.7	448.0	658.4	300.9	555.7	793.0
Residual Fuel Oil (nominal dollars per barrel)	58.15	62.27	83.86	96.51	63.57	146.41	239.76	69.29	183.36	296.21
Average	**249.1**	**211.8**	**268.5**	**294.3**	**241.0**	**427.7**	**617.5**	**270.8**	**524.0**	**749.3**

[1]Weighted average price delivered to U.S. refiners.
[2]Includes energy for combined heat and power plants, except those whose primary business is to sell electricity, or electricity and heat, to the public.
[3]E85 refers to a blend of 85 percent ethanol (renewable) and 15 percent motor gasoline (nonrenewable). To address cold starting issues, the percentage of ethanol varies seasonally. The annual average ethanol content of 74 percent is used for this forecast.
[4]Sales weighted-average price for all grades. Includes Federal, State and local taxes.
[5]Includes only kerosene type.
[6]Diesel fuel for on-road use. Includes Federal and State taxes while excluding county and local taxes.
[7]Includes electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public. Includes small power producers and exempt wholesale generators.
[8]Weighted averages of end-use fuel prices are derived from the prices in each sector and the corresponding sectoral consumption.
Note: Data for 2007 are model results and may differ slightly from official EIA data reports.
Sources: 2007 imported low sulfur light crude oil price: Energy Information Administration (EIA), Form EIA-856, “Monthly Foreign Crude Oil Acquisition Report.” 2007 imported crude oil price: EIA, *Annual Energy Review 2007*, DOE/EIA-0384(2007) (Washington, DC, June 2008). 2007 prices for motor gasoline, distillate fuel oil, and jet fuel are based on: EIA, *Petroleum Marketing Annual 2007*, DOE/EIA-0487(2007) (Washington, DC, August 2008). 2007 residential, commercial, industrial, and transportation sector petroleum product prices are derived from: EIA, Form EIA-782A, “Refiners’/Gas Plant Operators’ Monthly Petroleum Product Sales Report.” 2007 electric power prices based on: Federal Energy Regulatory Commission, FERC Form 423, “Monthly Report of Cost and Quality of Fuels for Electric Plants.” 2007 E85 prices derived from monthly prices in the Clean Cities Alternative Fuel Price Report. 2007 wholesale ethanol prices derived from Bloomburg U.S. average rack price. **Projections:** EIA, AEO2009 National Energy Modeling System runs LP2009.D122308A, AEO2009.D120908A, and HP2009.D121108A.

Table C6. International Liquids Supply and Disposition Summary
(Million Barrels per Day, Unless Otherwise Noted)

Supply and Disposition	2007	Projections								
		2010			2020			2030		
		Low Oil Price	Reference	High Oil Price	Low Oil Price	Reference	High Oil Price	Low Oil Price	Reference	High Oil Price
Crude Oil Prices (2007 dollars per barrel)[1]										
Imported Low Sulfur Light Crude Oil Price	72.33	58.61	80.16	91.08	50.43	115.45	184.60	50.23	130.43	200.42
Imported Crude Oil Price	63.83	55.45	77.56	88.31	46.77	112.05	181.18	46.44	124.60	197.72
Crude Oil Prices (nominal dollars per barrel)[1]										
Imported Low Sulfur Light Crude Oil Price	72.33	61.54	84.42	95.98	65.49	149.14	237.86	72.62	189.10	289.12
Imported Crude Oil Price	63.83	58.23	81.69	93.06	60.74	144.74	233.45	67.13	180.66	285.22
Conventional Production (Conventional)[2]										
OPEC[3]										
Middle East	22.97	23.55	22.77	22.02	31.04	25.22	18.53	36.75	28.34	18.33
North Africa	4.02	4.35	4.25	4.07	5.57	4.61	3.44	6.64	5.19	3.45
West Africa	4.12	4.97	4.81	4.58	6.54	5.23	3.74	7.94	5.92	3.67
South America	2.58	2.32	2.26	2.16	2.94	2.42	1.79	3.54	2.73	1.78
Total OPEC	**33.68**	**35.19**	**34.09**	**32.84**	**46.10**	**37.48**	**27.50**	**54.87**	**42.18**	**27.22**
Non-OPEC										
OECD										
United States (50 states)	8.11	8.86	8.81	8.82	8.60	9.71	10.46	8.58	10.44	11.48
Canada	2.05	1.93	1.90	1.86	1.27	1.25	1.16	1.02	1.02	0.92
Mexico	3.50	2.92	2.87	2.76	2.42	2.24	2.05	2.87	2.45	2.12
OECD Europe[4]	5.23	4.36	4.27	4.12	3.31	3.18	2.84	2.96	2.94	2.44
Japan	0.13	0.14	0.14	0.14	0.18	0.16	0.13	0.20	0.18	0.14
Australia and New Zealand	0.64	0.84	0.82	0.79	0.81	0.78	0.71	0.75	0.77	0.66
Total OECD	**19.66**	**19.05**	**18.80**	**18.49**	**16.58**	**17.32**	**17.34**	**16.38**	**17.81**	**17.76**
Non-OECD										
Russia	9.88	9.72	9.50	9.10	11.46	10.24	9.08	13.17	10.50	8.63
Other Europe and Eurasia[5]	2.88	3.66	3.58	3.43	4.97	4.50	4.10	5.88	4.86	4.31
China	3.90	3.84	3.75	3.59	3.68	3.52	3.09	3.14	3.19	2.57
Other Asia[6]	3.75	3.96	3.88	3.74	3.96	3.85	3.47	3.57	3.68	3.12
Middle East	1.52	1.45	1.42	1.36	1.44	1.40	1.25	1.31	1.36	1.13
Africa	2.41	2.71	2.65	2.53	2.82	2.72	2.41	2.86	2.98	2.43
Brazil	1.88	2.54	2.48	2.38	3.88	3.45	3.05	5.30	4.19	3.42
Other Central and South America	1.79	1.74	1.70	1.64	1.61	1.56	1.40	1.99	2.05	1.71
Total Non-OECD	**28.01**	**29.62**	**28.96**	**27.78**	**33.83**	**31.25**	**27.84**	**37.22**	**32.81**	**27.33**
Total Conventional Production	**81.35**	**83.86**	**81.85**	**79.11**	**96.52**	**86.04**	**72.68**	**108.47**	**92.80**	**72.31**
Unconventional Production[7]										
United States (50 states)	0.46	0.92	0.91	0.93	1.44	1.55	2.00	1.83	2.31	2.82
Other North America	1.38	1.85	1.92	1.92	2.79	3.34	3.47	3.67	4.31	5.25
OECD Europe[3]	0.11	0.09	0.13	0.13	0.09	0.19	0.24	0.12	0.27	0.43
Middle East	0.09	0.01	0.01	0.01	0.14	0.17	0.15	0.16	0.22	0.21
Africa.	0.23	0.20	0.27	0.27	0.28	0.50	0.55	0.35	0.72	0.94
Central and South America	1.02	1.24	1.15	1.07	2.49	2.04	2.06	3.92	3.16	3.97
Other	0.30	0.34	0.47	0.47	0.39	0.78	0.99	0.75	1.63	2.95
Total Unconventional Production	**3.58**	**4.66**	**4.85**	**4.79**	**7.62**	**8.56**	**9.47**	**10.81**	**12.61**	**16.57**
Total Production	**84.93**	**88.52**	**86.71**	**83.90**	**104.14**	**94.60**	**82.15**	**119.28**	**105.41**	**88.87**

Table C6. International Liquids Supply and Disposition Summary (Continued)
(Million Barrels per Day, Unless Otherwise Noted)

Supply and Disposition	2007	Projections								
		2010			2020			2030		
		Low Oil Price	Reference	High Oil Price	Low Oil Price	Reference	High Oil Price	Low Oil Price	Reference	High Oil Price
Consumption[8]										
OECD										
United States (50 states)	20.65	20.11	19.69	19.60	22.33	20.21	19.31	24.37	21.67	20.35
United States Territories	0.39	0.45	0.44	0.44	0.55	0.53	0.52	0.65	0.62	0.60
Canada	2.41	2.33	2.28	2.21	2.55	2.29	2.00	2.76	2.39	2.07
Mexico	2.10	2.10	2.06	1.99	2.51	2.28	1.97	3.03	2.67	2.20
OECD Europe[3]	15.36	15.04	14.74	14.31	15.74	14.24	12.20	16.31	14.27	12.20
Japan	5.02	4.81	4.68	4.46	4.85	4.27	3.39	4.80	4.02	3.11
South Korea	2.34	2.37	2.31	2.25	2.85	2.58	2.17	3.21	2.81	2.26
Australia and New Zealand	1.08	1.06	1.04	1.01	1.20	1.09	0.96	1.36	1.20	1.06
Total OECD	**49.35**	**48.27**	**47.24**	**46.26**	**52.58**	**47.50**	**42.51**	**56.49**	**49.64**	**43.86**
Non-OECD										
Russia	2.88	3.03	2.97	2.88	3.49	3.18	2.83	3.77	3.35	2.96
Other Europe and Eurasia[5]	2.24	2.39	2.34	2.26	2.89	2.64	2.27	3.33	2.96	2.55
China	7.63	8.71	8.50	8.13	12.45	11.29	9.14	17.10	15.08	11.14
India	2.46	2.67	2.60	2.47	3.92	3.51	2.76	5.22	4.52	3.12
Other Non-OECD Asia	6.28	6.52	6.39	6.06	8.52	7.75	6.34	10.23	9.03	7.27
Middle East	6.42	7.05	7.02	6.61	8.74	8.26	7.72	10.16	9.45	8.79
Africa	3.22	3.58	3.49	3.23	4.30	3.90	3.21	4.59	4.02	3.33
Brazil	2.37	2.61	2.55	2.37	3.14	2.84	2.39	3.79	3.32	2.65
Other Central and South America	3.35	3.69	3.60	3.62	4.12	3.73	2.99	4.61	4.04	3.22
Total Non-OECD	**36.85**	**40.25**	**39.46**	**37.64**	**51.55**	**47.10**	**39.64**	**62.80**	**55.77**	**45.01**
Total Consumption	**86.20**	**88.52**	**86.70**	**83.90**	**104.14**	**94.60**	**82.15**	**119.28**	**105.41**	**88.87**
OPEC Production[9]	34.38	36.09	34.75	33.42	48.16	38.51	28.21	58.13	43.63	28.27
Non-OPEC Production[9]	50.55	52.43	51.96	50.48	55.98	56.09	53.94	61.15	61.78	60.61
Net Eurasia Exports	9.52	10.49	10.24	9.76	13.93	12.37	11.14	17.24	13.25	10.85
OPEC Market Share (percent)	40.5	40.8	40.1	39.8	46.2	40.7	34.3	48.7	41.4	31.8

[1]Weighted average price delivered to U.S. refiners.

[2]Includes production of crude oil (including lease condensate), natural gas plant liquids, other hydrogen and hydrocarbons for refinery feedstocks, alcohol and other sources, and refinery gains.

[3]OPEC = Organization of Petroleum Exporting Countries - Algeria, Angola, Ecuador, Iran, Iraq, Kuwait, Libya, Nigeria, Qatar, Saudi Arabia, the United Arab Emirates, and Venezuela.

[4]OECD Europe = Organization for Economic Cooperation and Development - Austria, Belgium, Czech Republic, Denmark, Finland, France, Germany, Greece, Hungary, Iceland, Ireland, Italy, Luxembourg, the Netherlands, Norway, Poland, Portugal, Slovakia, Spain, Sweden, Switzerland, Turkey, and the United Kingdom.

[5]Other Europe and Eurasia = Albania, Armenia, Azerbaijan, Belarus, Bosnia and Herzegovina, Bulgaria, Croatia, Estonia, Georgia, Kazakhstan, Kyrgyzstan, Latvia, Lithuania, Macedonia, Malta, Moldova, Montenegro, Romania, Serbia, Slovenia, Tajikistan, Turkmenistan, Ukraine, and Uzbekistan.

[6]Other Asia = Afghanistan, Bangladesh, Bhutan, Brunei, Cambodia (Kampuchea), Fiji, French Polynesia, Guam, Hong Kong, Indonesia, Kiribati, Laos, Malaysia, Macau, Maldives, Mongolia, Myanmar (Burma), Nauru, Nepal, New Caledonia, Niue, North Korea, Pakistan, Papua New Guinea, Philippines, Samoa, Singapore, Solomon Islands, Sri Lanka, Taiwan, Thailand, Tonga, Vanuatu, and Vietnam.

[7]Includes liquids produced from energy crops, natural gas, coal, extra-heavy oil, oil sands, and shale. Includes both OPEC and non-OPEC producers in the regional breakdown.

[8]Includes both OPEC and non-OPEC consumers in the regional breakdown.

[9]Includes both conventional and unconventional liquids production.

Note: Totals may not equal sum of components due to independent rounding. Data for 2007 are model results and may differ slightly from official EIA data reports.

Sources: 2007 low sulfur light crude oil price: Energy Information Administration (EIA), Form EIA-856, "Monthly Foreign Crude Oil Acquisition Report." 2007 imported crude oil price: EIA, *Annual Energy Review 2007*, DOE/EIA-0384(2007) (Washington, DC, June 2008). **2007 quantities and projections:** EIA, AEO2009 National Energy Modeling System runs LP2009.D122308A, AEO2009.D120908A, and HP2009.D121108A and EIA, Generate World Oil Balance Model.

Appendix D

Results from Side Cases

Table D1. Key Results for Residential and Commercial Sector Technology Cases

Energy Consumption	2007	2010				2020			
		2009 Technology	Reference	High Technology	Best Available Technology	2009 Technology	Reference	High Technology	Best Available Technology
Residential									
Energy Consumption (quadrillion Btu)									
Liquefied Petroleum Gases	0.50	0.49	0.49	0.49	0.48	0.50	0.49	0.48	0.46
Kerosene	0.08	0.08	0.08	0.08	0.07	0.08	0.07	0.07	0.06
Distillate Fuel Oil	0.78	0.72	0.72	0.72	0.71	0.62	0.60	0.58	0.54
Liquid Fuels and Other Petroleum	1.35	1.29	1.29	1.28	1.27	1.20	1.16	1.13	1.06
Natural Gas	4.86	4.93	4.92	4.90	4.81	5.25	5.10	4.94	4.24
Coal	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Renewable Energy[1]	0.43	0.43	0.43	0.43	0.42	0.49	0.48	0.47	0.44
Electricity	4.75	4.81	4.80	4.78	4.35	5.26	5.12	4.82	4.04
Delivered Energy	**11.40**	**11.46**	**11.44**	**11.39**	**10.87**	**12.20**	**11.86**	**11.38**	**9.79**
Electricity Related Losses	10.36	10.46	10.44	10.40	9.48	11.11	10.81	10.19	8.53
Total	**21.76**	**21.92**	**21.88**	**21.80**	**20.34**	**23.31**	**22.67**	**21.57**	**18.32**
Delivered Energy Intensity (million Btu per household)	**100.2**	**98.6**	**98.4**	**98.0**	**93.4**	**94.0**	**91.4**	**87.7**	**75.5**
Nonmarketed Renewables Consumption (quadrillion Btu)	**0.01**	**0.01**	**0.01**	**0.01**	**0.01**	**0.06**	**0.07**	**0.08**	**0.10**
Commercial									
Energy Consumption (quadrillion Btu)									
Liquefied Petroleum Gases	0.09	0.09	0.09	0.09	0.09	0.10	0.10	0.10	0.10
Motor Gasoline[2]	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05
Kerosene	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Distillate Fuel Oil	0.41	0.36	0.36	0.36	0.36	0.35	0.34	0.34	0.35
Residual Fuel Oil	0.08	0.07	0.07	0.07	0.07	0.08	0.08	0.08	0.08
Liquid Fuels and Other Petroleum	0.63	0.58	0.58	0.58	0.58	0.59	0.58	0.58	0.59
Natural Gas	3.10	3.15	3.14	3.12	3.11	3.38	3.34	3.27	3.20
Coal	0.07	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06
Renewable Energy[3]	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12
Electricity	4.58	4.76	4.75	4.74	4.66	5.74	5.57	5.41	4.66
Delivered Energy	**8.50**	**8.67**	**8.66**	**8.63**	**8.53**	**9.89**	**9.69**	**9.45**	**8.64**
Electricity Related Losses	9.99	10.36	10.35	10.32	10.14	12.12	11.77	11.44	9.85
Total	**18.49**	**19.04**	**19.01**	**18.95**	**18.68**	**22.01**	**21.46**	**20.89**	**18.49**
Delivered Energy Intensity (thousand Btu per square foot)	**110.0**	**106.9**	**106.7**	**106.3**	**105.2**	**107.1**	**105.0**	**102.5**	**93.7**
Commercial Sector Generation									
Net Summer Generation Capacity (megawatts)									
Natural Gas	658	697	699	699	700	1039	1244	1454	1464
Solar Photovoltaic	375	749	749	749	749	1190	1275	1434	1717
Wind	18	18	18	18	18	52	64	99	108
Electricity Generation (billion kilowatthours)									
Natural Gas	4.74	5.02	5.03	5.03	5.04	7.48	9.00	10.53	10.60
Solar Photovoltaic	0.59	1.20	1.20	1.20	1.20	1.90	2.06	2.32	2.77
Wind	0.02	0.02	0.02	0.02	0.02	0.07	0.09	0.14	0.16
Nonmarketed Renewables Consumption (quadrillion Btu)	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**	**0.04**	**0.04**

[1]Includes wood used for residential heating. See Table A4 and/or Table A17 for estimates of nonmarketed renewable energy consumption for geothermal heat pumps, solar thermal hot water heating, and solar photovoltaic electricity generation.
[2]Includes ethanol (blends of 10 percent or less) and ethers blended into gasoline.
[3]Includes commercial sector consumption of wood and wood waste, landfill gas, municipal solid waste, and other biomass for combined heat and power.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Data for 2007 are model results and may differ slightly from official EIA data reports. Side cases were run without the fully integrated modeling system, so not all feedbacks are captured. The reference case ratio of electricity losses to electricity use was used to compute electricity losses for the technology cases.
Source: Energy Information Administration, AEO2009 National Energy Modeling System, runs BLDFRZN.D121008A, AEO2009.D120908A, BLDHIGH.D121008A, and BLDBEST.D121008A.

2030				Annual Growth 2007-2030 (percent)			
2009 Technology	Reference	High Technology	Best Available Technology	2009 Technology	Reference	High Technology	Best Available Technology
0.54	0.52	0.49	0.47	0.3%	0.2%	-0.1%	-0.3%
0.08	0.07	0.07	0.05	-0.2%	-0.5%	-0.9%	-1.9%
0.55	0.51	0.49	0.43	-1.5%	-1.8%	-2.0%	-2.5%
1.16	1.10	1.04	0.95	-0.7%	-0.9%	-1.1%	-1.5%
5.36	5.07	4.88	3.64	0.4%	0.2%	0.0%	-1.2%
0.01	0.01	0.01	0.01	-0.5%	-0.8%	-0.9%	-1.0%
0.53	0.50	0.48	0.44	0.9%	0.7%	0.5%	0.1%
6.01	5.69	5.31	4.22	1.0%	0.8%	0.5%	-0.5%
13.07	**12.36**	**11.72**	**9.26**	**0.6%**	**0.4%**	**0.1%**	**-0.9%**
12.34	11.69	10.90	8.66	0.8%	0.5%	0.2%	-0.8%
25.42	**24.05**	**22.62**	**17.92**	**0.7%**	**0.4%**	**0.2%**	**-0.8%**
92.6	**87.6**	**83.0**	**65.6**	**-0.3%**	**-0.6%**	**-0.8%**	**-1.8%**
0.06	**0.08**	**0.11**	**0.15**	**10.0%**	**11.5%**	**12.9%**	**14.5%**
0.10	0.10	0.10	0.10	0.3%	0.3%	0.3%	0.3%
0.05	0.05	0.05	0.05	0.4%	0.4%	0.4%	0.4%
0.01	0.01	0.01	0.01	1.4%	1.4%	1.4%	1.4%
0.35	0.34	0.34	0.35	-0.7%	-0.8%	-0.8%	-0.6%
0.08	0.08	0.08	0.08	0.2%	0.3%	0.2%	0.2%
0.59	0.59	0.58	0.60	-0.3%	-0.3%	-0.3%	-0.2%
3.56	3.54	3.52	3.43	0.6%	0.6%	0.6%	0.4%
0.06	0.06	0.06	0.06	-0.0%	-0.0%	-0.0%	-0.0%
0.12	0.12	0.12	0.12	0.0%	0.0%	0.0%	0.0%
6.65	6.31	5.98	4.76	1.6%	1.4%	1.2%	0.2%
10.99	**10.62**	**10.27**	**8.98**	**1.1%**	**1.0%**	**0.8%**	**0.2%**
13.66	12.96	12.28	9.79	1.4%	1.1%	0.9%	-0.1%
24.65	**23.59**	**22.56**	**18.77**	**1.3%**	**1.1%**	**0.9%**	**0.1%**
106.4	**102.9**	**99.5**	**87.0**	**-0.1%**	**-0.3%**	**-0.4%**	**-1.0%**
1991	3524	4897	5147	4.9%	7.6%	9.1%	9.4%
1547	2296	3485	5449	6.4%	8.2%	10.2%	12.3%
214	286	704	1313	11.4%	12.8%	17.3%	20.5%
14.34	25.59	35.57	37.39	4.9%	7.6%	9.2%	9.4%
2.44	3.74	5.72	8.94	6.4%	8.4%	10.4%	12.5%
0.31	0.42	1.01	1.84	11.9%	13.3%	17.7%	20.8%
0.04	**0.04**	**0.05**	**0.07**	**1.4%**	**2.0%**	**2.9%**	**4.0%**

Table D2. Key Results for Industrial Sector Technology Cases

Consumption and Indicators	2007	2010			2020			2030		
		2009 Technology	Reference	High Technology	2009 Technology	Reference	High Technology	2009 Technology	Reference	High Technology
Value of Shipments (billion 2000 dollars)										
Manufacturing	4261	3963	3963	3963	5150	5150	5150	6671	6671	6671
Nonmanufacturing	1490	1277	1277	1277	1603	1603	1603	1780	1780	1780
Total	**5750**	**5240**	**5240**	**5240**	**6753**	**6753**	**6753**	**8451**	**8451**	**8451**
Energy Consumption excluding Refining[1] (quadrillion Btu)										
Liquefied Petroleum Gases	2.34	2.01	1.98	1.96	2.04	1.77	1.55	1.95	1.66	1.42
Heat and Power	0.18	0.16	0.15	0.15	0.17	0.15	0.15	0.18	0.16	0.15
Feedstocks	2.16	1.85	1.83	1.80	1.88	1.61	1.40	1.78	1.50	1.27
Motor Gasoline	0.36	0.35	0.34	0.34	0.37	0.34	0.32	0.40	0.36	0.32
Distillate Fuel Oil	1.27	1.17	1.17	1.16	1.28	1.18	1.10	1.39	1.23	1.11
Residual Fuel Oil	0.24	0.15	0.15	0.15	0.18	0.16	0.15	0.19	0.16	0.15
Petrochemical Feedstocks	1.30	1.01	1.01	1.00	1.18	1.13	1.08	1.14	1.05	0.99
Petroleum Coke	0.36	0.27	0.27	0.26	0.33	0.29	0.26	0.38	0.31	0.27
Asphalt and Road Oil	1.19	0.98	0.96	0.95	1.26	1.08	0.93	1.38	1.12	0.92
Miscellaneous Petroleum[2]	0.62	0.31	0.30	0.30	0.27	0.21	0.19	0.30	0.21	0.19
Petroleum Subtotal	7.68	6.25	6.18	6.13	6.91	6.15	5.58	7.13	6.10	5.37
Natural Gas Heat and Power	5.14	5.08	5.02	5.01	5.69	4.86	4.79	6.17	5.11	4.97
Natural Gas Feedstocks	0.55	0.51	0.51	0.50	0.59	0.50	0.44	0.54	0.44	0.37
Lease and Plant Fuel[3]	1.20	1.27	1.27	1.27	1.33	1.33	1.33	1.47	1.47	1.47
Natural Gas Subtotal	6.89	6.87	6.80	6.79	7.61	6.69	6.56	8.17	7.02	6.81
Metallurgical Coal and Coke[4]	0.62	0.57	0.56	0.56	0.56	0.50	0.44	0.57	0.49	0.39
Other Industrial Coal	1.15	1.18	1.18	1.17	1.17	1.09	1.05	1.20	1.10	1.03
Coal Subtotal	1.77	1.75	1.74	1.73	1.72	1.60	1.49	1.76	1.59	1.42
Renewables[5]	1.64	1.48	1.48	1.48	1.61	1.64	1.69	1.88	1.96	2.08
Purchased Electricity	3.27	3.18	3.15	3.10	3.49	3.27	3.06	3.83	3.45	3.11
Delivered Energy	**21.26**	**19.53**	**19.36**	**19.24**	**21.34**	**19.35**	**18.38**	**22.77**	**20.11**	**18.79**
Electricity Related Losses	7.13	6.91	6.86	6.75	7.38	6.91	6.66	7.87	7.09	6.76
Total	**28.40**	**26.44**	**26.22**	**25.99**	**28.72**	**26.25**	**25.04**	**30.65**	**27.20**	**25.56**
Delivered Energy Use per Dollar of Shipments (thousand Btu per 2000 dollar)	**3.70**	**3.73**	**3.69**	**3.67**	**3.16**	**2.86**	**2.72**	**2.69**	**2.38**	**2.22**
Onsite Industrial Combined Heat and Power										
Capacity (gigawatts)	22.02	23.00	23.04	23.13	25.60	25.84	26.71	28.38	29.16	31.42
Generation (billion kilowatthours)	119.66	125.89	126.15	126.80	144.22	145.85	151.51	163.93	169.15	183.55

[1]Fuel consumption includes energy for combined heat and power plants, except those whose primary business is to sell electricity, or electricity and heat, to the public.
[2]Includes lubricants and miscellaneous petroleum products.
[3]Represents natural gas used in the field gathering and processing plant machinery.
[4]Includes net coal coke imports.
[5]Includes consumption of energy from hydroelectric, wood and wood waste, municipal solid waste, and other biomass.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Data for 2007 are model results and may differ slightly from official EIA data reports. Side cases were run without the fully integrated modeling system, so not all feedbacks are captured. The reference case ratio of electricity losses to electricity use was used to compute electricity losses for the technology cases.
Source: Energy Information Administration, AEO2009 National Energy Modeling System runs INDFRZN.D121608A, AEO2009.D120908A, and INDHIGH.D121608A.

Table D3. Key Results for Transportation Sector Technology Cases

Consumption and Indicators	2007	2010			2020			2030		
		Low Technology	Reference	High Technology	Low Technology	Reference	High Technology	Low Technology	Reference	High Technology
Level of Travel										
(billion vehicle miles traveled)										
Light-Duty Vehicles less than 8,500	2702	2747	2747	2747	3155	3161	3165	3813	3827	3837
Commercial Light Trucks[1]	72	67	67	67	85	85	85	105	105	105
Freight Trucks greater than 10,000	248	232	232	232	303	303	303	378	378	378
(billion seat miles available)										
Air	1036	951	951	951	1138	1138	1138	1410	1410	1410
(billion ton miles traveled)										
Rail	1733	1664	1664	1664	1927	1927	1927	2193	2193	2193
Domestic Shipping	662	629	629	629	744	744	744	839	839	839
Energy Efficiency Indicators										
(miles per gallon)										
Tested New Light-Duty Vehicle[2]	26.3	26.9	26.9	27.2	34.6	35.5	36.0	36.9	38.0	39.0
New Car[2]	30.3	30.6	30.7	31.4	38.1	39.1	40.2	40.4	41.4	43.2
New Light Truck[2]	23.1	23.6	23.6	23.6	30.6	30.7	30.9	32.5	33.1	33.7
Light-Duty Stock[3]	20.6	20.7	20.7	20.7	24.4	24.7	25.0	28.3	28.9	29.5
New Commercial Light Truck[1]	15.4	15.6	15.7	15.7	19.5	19.6	19.8	19.8	20.3	20.9
Stock Commercial Light Truck[1]	14.4	14.8	14.8	14.8	17.4	17.6	17.7	19.5	19.8	20.1
Freight Truck	6.0	6.0	6.0	6.0	6.3	6.5	6.8	6.5	6.9	7.2
(seat miles per gallon)										
Aircraft	62.8	64.4	64.4	64.5	67.8	68.1	68.8	72.1	73.6	75.3
(ton miles per thousand Btu)										
Rail	2.9	2.9	2.9	2.9	2.9	3.0	3.1	2.9	3.0	3.2
Domestic Shipping	2.0	2.0	2.0	2.0	2.0	2.0	2.1	2.0	2.0	2.2
Energy Use (quadrillion Btu)										
by Mode										
Light-Duty Vehicles	16.47	16.21	16.20	16.19	16.01	15.80	15.66	16.83	16.51	16.22
Commercial Light Trucks[1]	0.62	0.57	0.57	0.57	0.61	0.61	0.60	0.68	0.67	0.66
Bus Transportation	0.27	0.27	0.27	0.27	0.28	0.27	0.26	0.30	0.28	0.27
Freight Trucks	5.15	4.82	4.81	4.80	6.01	5.79	5.59	7.25	6.90	6.58
Rail, Passenger	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.06	0.06	0.06
Rail, Freight	0.59	0.57	0.57	0.57	0.66	0.65	0.63	0.75	0.73	0.69
Shipping, Domestic	0.34	0.32	0.32	0.32	0.38	0.37	0.36	0.43	0.42	0.38
Shipping, International	0.88	0.80	0.80	0.80	0.90	0.90	0.89	0.91	0.91	0.90
Recreational Boats	0.25	0.25	0.25	0.25	0.26	0.26	0.26	0.28	0.28	0.28
Air	2.71	2.45	2.45	2.45	2.89	2.87	2.84	3.61	3.54	3.46
Military Use	0.70	0.74	0.74	0.74	0.74	0.74	0.74	0.78	0.78	0.78
Lubricants	0.14	0.14	0.14	0.14	0.15	0.15	0.15	0.15	0.15	0.15
Pipeline Fuel	0.64	0.64	0.64	0.64	0.69	0.69	0.69	0.72	0.72	0.72
Total	**28.82**	**27.82**	**27.81**	**27.78**	**29.63**	**29.15**	**28.72**	**32.74**	**31.94**	**31.14**
by Fuel										
Liquefied Petroleum Gases	0.02	0.01	0.01	0.01	0.01	0.01	0.01	0.02	0.02	0.01
E85[4]	0.00	0.00	0.00	0.00	0.88	0.85	0.85	2.32	2.18	2.19
Motor Gasoline[5]	17.29	16.94	16.93	16.92	15.72	15.56	15.42	14.63	14.49	14.24
Jet Fuel[6]	3.23	3.00	3.00	3.00	3.43	3.42	3.39	4.19	4.12	4.04
Distillate Fuel Oil[7]	6.48	6.14	6.13	6.12	7.63	7.36	7.11	9.54	9.09	8.64
Residual Fuel Oil	0.95	0.86	0.86	0.86	0.98	0.98	0.97	1.01	1.00	0.99
Liquid Hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Other Petroleum[8]	0.17	0.17	0.17	0.17	0.18	0.18	0.18	0.18	0.18	0.18
Liquid Fuels and Other Petroleum	28.14	27.13	27.11	27.09	28.84	28.36	27.94	31.89	31.09	30.29
Pipeline Fuel Natural Gas	0.64	0.64	0.64	0.64	0.69	0.69	0.69	0.72	0.72	0.72
Compressed Natural Gas	0.02	0.03	0.03	0.03	0.07	0.07	0.06	0.09	0.09	0.08
Electricity	0.02	0.02	0.02	0.02	0.03	0.03	0.04	0.04	0.05	0.05
Delivered Energy	**28.82**	**27.82**	**27.81**	**27.78**	**29.63**	**29.15**	**28.72**	**32.74**	**31.94**	**31.14**
Electricity Related Losses	0.05	0.05	0.05	0.05	0.06	0.07	0.07	0.09	0.10	0.11
Total	**28.87**	**27.82**	**27.86**	**27.78**	**29.63**	**29.22**	**28.72**	**32.74**	**32.05**	**31.14**

[1]Commercial trucks 8,500 to 10,000 pounds.
[2]Environmental Protection Agency rated miles per gallon.
[3]Combined car and light truck "on-the-road" estimate.
[4]E85 refers to a blend of 85 percent ethanol (renewable) and 15 percent motor gasoline (nonrenewable). To address cold starting issues, the percentage of ethanol varies seasonally. The annual average ethanol content of 74 percent is used for this forecast.
[5]Includes ethanol (blends of 10 percent or less) and ethers blended into gasoline.
[6]Includes only kerosene type.
[7]Diesel fuel for on- and off- road use.
[8]Includes aviation gasoline and lubricants.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Data for 2007 are model results and may differ slightly from official EIA data reports. Side cases were run without the fully integrated modeling system, so not all feedbacks are captured. The reference case ratio of electricity losses to electricity use was used to compute electricity losses for the technology cases.
Source: Energy Information Administration, AEO2009 National Energy Modeling System runs TRNLOW.D011409A, AEO2009.D120908A, and TRNHIGH.D011409A.

Table D4. Key Results for Integrated Technology Cases

Consumption and Emissions	2007	2010			2020			2030		
		2009 Technology	Reference	High Technology	2009 Technology	Reference	High Technology	2009 Technology	Reference	High Technology
Energy Consumption by Sector (quadrillion Btu)										
Residential	11.40	11.46	11.44	11.40	12.13	11.86	11.44	12.97	12.36	11.82
Commercial	8.50	8.67	8.66	8.63	9.78	9.69	9.56	10.86	10.62	10.40
Industrial[1]	25.29	24.05	23.83	23.72	26.64	24.73	23.89	28.97	26.33	25.13
Transportation	28.82	27.83	27.81	27.78	29.59	29.15	28.76	32.61	31.94	31.23
Electric Power[2]	40.67	41.18	41.02	40.82	45.26	44.22	42.90	49.50	48.03	46.13
Total	**101.89**	**100.24**	**99.85**	**99.50**	**108.82**	**105.44**	**102.85**	**118.38**	**113.56**	**109.77**
Energy Consumption by Fuel (quadrillion Btu)										
Liquid Fuels and Other Petroleum[3]	40.75	37.97	37.89	37.82	40.14	38.93	38.06	43.36	41.60	40.13
Natural Gas	23.70	23.26	23.20	22.98	25.44	24.09	22.87	27.81	25.04	23.52
Coal	22.74	22.93	22.91	22.85	24.50	23.98	23.34	27.16	26.56	25.38
Nuclear Power	8.41	8.45	8.45	8.45	9.01	8.99	9.20	8.81	9.47	9.72
Renewable Energy[4]	6.05	7.42	7.20	7.19	9.53	9.26	9.21	10.89	10.67	10.88
Other[5]	0.23	0.21	0.21	0.21	0.22	0.19	0.17	0.36	0.22	0.14
Total	**101.89**	**100.24**	**99.85**	**99.50**	**108.82**	**105.44**	**102.85**	**118.38**	**113.56**	**109.77**
Energy Intensity (thousand Btu per 2000 dollar of GDP)	**8.84**	**8.51**	**8.48**	**8.45**	**7.03**	**6.79**	**6.61**	**5.90**	**5.65**	**5.45**
Carbon Dioxide Emissions by Sector (million metric tons)										
Residential	346	351	351	349	360	351	343	363	344	333
Commercial	216	215	214	213	225	226	224	236	236	236
Industrial[1]	987	974	965	962	1055	973	943	1145	1030	980
Transportation	2009	1888	1886	1884	1969	1937	1908	2122	2075	2021
Electric Power[6]	2433	2383	2385	2373	2550	2497	2398	2840	2729	2574
Total	**5991**	**5810**	**5801**	**5782**	**6159**	**5982**	**5817**	**6705**	**6414**	**6144**
Carbon Dioxide Emissions by Fuel (million metric tons)										
Petroleum	2580	2399	2396	2393	2485	2427	2386	2654	2564	2485
Natural Gas	1237	1221	1218	1207	1335	1265	1202	1462	1318	1238
Coal	2162	2178	2176	2171	2327	2278	2217	2577	2521	2410
Other[7]	12	12	12	12	12	12	12	12	12	12
Total	**5991**	**5810**	**5801**	**5782**	**6159**	**5982**	**5817**	**6705**	**6414**	**6144**
Carbon Dioxide Emissions (tons per person)	**19.8**	**18.7**	**18.6**	**18.6**	**18.0**	**17.5**	**17.0**	**17.9**	**17.1**	**16.4**

[1]Includes energy for combined heat and power plants, except those whose primary business is to sell electricity, or electricity and heat, to the public.
[2]Includes electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public.
[3]Includes petroleum-derived fuels and non-petroleum derived fuels, such as ethanol and biodiesel, and coal-based synthetic liquids. Petroleum coke, which is a solid, is included. Also included are natural gas plant liquids, crude oil consumed as a fuel, and liquid hydrogen.
[4]Includes grid-connected electricity from conventional hydroelectric; wood and wood waste; landfill gas; biogenic municipal solid waste; other biomass; wind; photovoltaic and solar thermal sources; and non-electric energy from renewable sources, such as active and passive solar systems, and wood; and both the ethanol and gasoline components of E85, but not the ethanol component of blends less than 85 percent. Excludes electricity imports using renewable sources and nonmarketed renewable energy.
[5]Includes non-biogenic municipal waste and net electricity imports.
[6]Includes electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public.
[7]Includes emissions from geothermal power and nonbiogenic emissions from municipal solid waste.
Btu = British thermal unit.
GDP = Gross domestic product.
Note: Includes end-use, fossil electricity, and renewable technology assumptions. Totals may not equal sum of components due to independent rounding. Data for 2007 are model results and may differ slightly from official EIA data reports.
Source: Energy Information Administration, AEO2009 National Energy Modeling System runs LTRKITEN.D011509A, AEO2009.D120908A, and HTRKITEN.D011509A.

Table D5. Key Results for Advanced Nuclear Cost Cases
(Gigawatts, Unless Otherwise Noted)

Net Summer Capacity, Generation, Emissions, and Fuel Prices	2007	2010			2020			2030		
		High Nuclear Cost	Reference	Low Nuclear Cost	High Nuclear Cost	Reference	Low Nuclear Cost	High Nuclear Cost	Reference	Low Nuclear Cost
Capacity										
Coal Steam	311.2	321.0	321.0	321.0	327.1	327.0	327.0	364.0	352.5	338.7
Oil and Natural Gas Steam	118.8	118.4	118.4	118.4	101.3	101.8	101.8	100.6	100.5	100.3
Combined Cycle	181.0	194.8	194.8	194.8	205.2	202.7	199.9	260.0	237.7	231.6
Combustion Turbine/Diesel	133.3	142.0	142.1	142.2	155.2	155.8	155.2	198.2	201.0	204.3
Nuclear Power	100.5	101.2	101.2	101.2	105.1	108.4	113.8	74.3	112.6	132.2
Pumped Storage	21.5	21.5	21.5	21.5	21.5	21.5	21.5	21.5	21.5	21.5
Fuel Cells	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Renewable Sources	101.5	115.5	115.6	115.5	122.7	122.3	122.4	142.3	138.8	136.9
Distributed Generation (Natural Gas)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.2	0.3	0.3
Combined Heat and Power[1]	27.8	32.5	32.6	32.5	47.3	47.3	47.3	62.8	62.6	62.3
Total	**995.6**	**1046.9**	**1047.1**	**1047.0**	**1085.3**	**1086.8**	**1088.8**	**1223.8**	**1227.4**	**1228.0**
Cumulative Additions										
Coal Steam	0.0	11.3	11.3	11.3	18.0	18.0	18.0	55.0	43.6	29.7
Oil and Natural Gas Steam	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Combined Cycle	0.0	13.8	13.8	13.8	24.1	21.7	18.8	79.0	56.6	50.5
Combustion Turbine/Diesel	0.0	9.1	9.1	9.2	27.1	27.8	27.1	70.0	73.0	76.3
Nuclear Power	0.0	0.0	0.0	0.0	1.2	4.5	9.9	1.2	13.1	32.7
Pumped Storage	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Fuel Cells	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Renewable Sources	0.0	14.0	14.1	14.0	21.2	20.9	21.0	40.8	37.4	35.4
Distributed Generation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.2	0.3	0.3
Combined Heat and Power[1]	0.0	4.7	4.8	4.7	19.5	19.5	19.5	35.0	34.8	34.6
Total	**0.0**	**52.9**	**53.1**	**53.1**	**111.2**	**112.4**	**114.4**	**281.3**	**258.7**	**259.5**
Cumulative Retirements	**0.0**	**2.3**	**2.3**	**2.3**	**24.8**	**24.5**	**24.5**	**56.4**	**30.2**	**30.4**
Generation by Fuel (billion kilowatthours)										
Coal	2002	2038	2038	2038	2127	2125	2118	2464	2367	2252
Petroleum	61	43	43	43	45	45	44	46	46	46
Natural Gas	814	738	737	738	816	801	771	1037	880	858
Nuclear Power	806	809	809	809	840	862	903	594	907	1062
Pumped Storage	0	1	1	1	1	1	1	1	1	1
Renewable Sources	318	415	415	415	550	549	548	629	614	610
Distributed Generation	0	0	0	0	0	0	0	0	0	0
Combined Heat and Power[1]	153	174	174	175	237	237	237	338	337	336
Total	**4155**	**4217**	**4217**	**4218**	**4616**	**4618**	**4622**	**5109**	**5153**	**5163**
Carbon Dioxide Emissions by the Electric Power Sector (million metric tons)[2]										
Petroleum	66	38	38	38	40	40	39	41	41	41
Natural Gas	376	341	341	341	362	357	346	431	378	370
Coal	1980	1995	1995	1995	2090	2089	2080	2375	2299	2203
Other[3]	12	12	12	12	12	12	12	12	12	12
Total	**2433**	**2385**	**2385**	**2385**	**2503**	**2497**	**2477**	**2858**	**2729**	**2625**
Prices to the Electric Power Sector[2] (2007 dollars per million Btu)										
Petroleum	9.42	13.60	13.64	13.57	19.01	19.01	19.01	21.20	21.28	21.18
Natural Gas	7.02	6.59	6.59	6.58	7.24	7.15	7.02	9.29	8.70	8.65
Coal	1.78	1.89	1.89	1.89	1.92	1.92	1.92	2.08	2.04	2.01

[1]Includes combined heat and power plants and electricity-only plants in commercial and industrial sectors. Includes small on-site generating systems in the residential, commercial, and industrial sectors used primarily for own-use generation, but which may also sell some power to the grid. Excludes off-grid photovoltaics and other generators not connected to the distribution or transmission systems.
[2]Includes electricity-only and combined heat and power plants whose primary business to sell electricity, or electricity and heat, to the public.
[3]Includes emissions from geothermal power and nonbiogenic emissions from municipal solid waste.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Data for 2007 are model results and may differ slightly from official EIA data reports.
Source: Energy Information Administration, AEO2009 National Energy Modeling System runs HCNUC09.D121108A, AEO2009.D120908A, and LCNUC09.D121108A.

Table D6. Key Results for Electric Power Sector Fossil Technology Cases
(Gigawatts, Unless Otherwise Noted)

Net Summer Capacity, Generation Consumption, and Emissions	2007	2010			2020			2030		
		High Fossil Cost	Reference	Low Fossil Cost	High Fossil Cost	Reference	Low Fossil Cost	High Fossil Cost	Reference	Low Fossil Cost
Capacity										
Pulverized Coal	310.7	320.5	320.5	320.5	324.1	324.0	324.3	327.0	345.6	369.5
Coal Gasification Combined-Cycle	0.5	0.5	0.5	0.5	3.0	3.0	3.0	3.0	6.9	20.0
Conventional Natural Gas Combined-Cycle	181.0	194.8	194.8	194.8	196.3	196.4	196.6	196.6	196.5	196.9
Advanced Natural Gas Combined-Cycle	0.0	0.0	0.0	0.0	2.5	6.3	12.1	29.8	41.1	47.4
Conventional Combustion Turbine	133.3	139.6	140.6	140.9	136.5	138.5	138.8	145.6	140.9	138.9
Advanced Combustion Turbine	0.0	1.5	1.5	1.5	16.9	17.3	20.7	62.7	60.1	51.9
Fuel Cells	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Nuclear	100.5	101.2	101.2	101.2	110.2	108.4	105.1	119.1	112.6	100.7
Oil and Natural Gas Steam	118.8	118.4	118.4	118.4	99.9	101.8	103.9	99.8	100.5	100.2
Renewable Sources/Pumped Storage	122.9	137.0	137.0	137.0	143.7	143.6	143.4	170.0	160.1	155.0
Distributed Generation	0.0	0.0	0.0	0.0	0.1	0.0	0.0	1.8	0.3	0.0
Combined Heat and Power[1]	27.8	32.5	32.6	32.5	47.4	47.3	47.2	62.9	62.6	61.7
Total	**995.6**	**1046.0**	**1047.1**	**1047.3**	**1080.6**	**1086.6**	**1094.9**	**1218.3**	**1227.2**	**1242.3**
Cumulative Additions										
Pulverized Coal	0.0	11.3	11.3	11.3	16.6	16.6	16.8	19.6	38.2	62.5
Coal Gasification Combined-Cycle	0.0	0.0	0.0	0.0	1.4	1.4	1.4	1.4	5.4	18.0
Conventional Natural Gas Combined-Cycle	0.0	13.8	13.8	13.8	15.3	15.4	15.6	15.5	15.5	15.9
Advanced Natural Gas Combined-Cycle	0.0	0.0	0.0	0.0	2.5	6.3	12.1	29.8	41.1	47.4
Conventional Combustion Turbine	0.0	6.6	7.6	8.0	9.0	10.5	10.1	18.0	12.9	10.2
Advanced Combustion Turbine	0.0	1.5	1.5	1.5	16.9	17.3	20.7	62.7	60.1	51.9
Fuel Cells	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Nuclear	0.0	0.0	0.0	0.0	6.3	4.5	1.2	19.6	13.1	1.2
Oil and Natural Gas Steam	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Renewable Sources	0.0	14.1	14.1	14.1	21.1	20.9	20.7	47.3	37.4	32.3
Distributed Generation	0.0	0.0	0.0	0.0	0.1	0.0	0.0	1.8	0.3	0.0
Combined Heat and Power[1]	0.0	4.7	4.8	4.7	19.6	19.5	19.4	35.1	34.8	33.9
Total	**0.0**	**52.0**	**53.1**	**53.4**	**108.7**	**112.4**	**117.8**	**250.9**	**258.7**	**273.3**
Cumulative Retirements	**0.0**	**2.3**	**2.3**	**2.3**	**26.8**	**24.5**	**21.6**	**31.4**	**30.2**	**29.7**
Generation by Fuel (billion kilowatthours)										
Coal	2002	2038	2038	2038	2122	2125	2129	2225	2367	2596
Petroleum	61	43	43	43	45	45	45	46	46	46
Natural Gas	814	737	737	737	786	801	822	908	880	808
Nuclear Power	806	809	809	809	875	862	840	959	907	817
Renewable Sources/Pumped Storage	319	416	415	416	551	549	549	654	615	605
Distributed Generation	0	0	0	0	0	0	0	3	0	0
Combined Heat and Power[1]	153	174	174	174	237	237	237	339	337	333
Total	**4155**	**4217**	**4217**	**4217**	**4616**	**4618**	**4622**	**5134**	**5153**	**5206**
Fuel Consumption by the Electric Power Sector (quadrillion Btu)[2]										
Coal	20.84	21.03	21.03	21.03	21.97	22.01	22.05	23.09	24.25	26.03
Petroleum	0.67	0.49	0.49	0.49	0.51	0.51	0.51	0.52	0.53	0.53
Natural Gas	7.06	6.43	6.42	6.43	6.64	6.73	6.85	7.39	7.12	6.55
Nuclear Power	8.41	8.45	8.45	8.45	9.13	8.99	8.77	10.01	9.47	8.53
Renewable Sources	3.45	4.43	4.42	4.42	5.81	5.79	5.79	6.73	6.43	6.33
Total	**40.56**	**40.95**	**40.94**	**40.94**	**44.19**	**44.16**	**44.09**	**47.86**	**47.93**	**48.10**
Carbon Dioxide Emissions by the Electric Power Sector (million metric tons)[2]										
Coal	1980	1995	1995	1994	2085	2089	2092	2190	2299	2464
Petroleum	66	38	38	38	40	40	40	40	41	41
Natural Gas	376	341	341	341	352	357	363	392	378	348
Other[3]	12	12	12	12	12	12	12	12	12	12
Total	**2433**	**2385**	**2385**	**2385**	**2488**	**2497**	**2507**	**2634**	**2729**	**2864**

[1]Includes combined heat and power plants and electricity-only plants in the commercial and industrial sectors. Includes small on-site generating systems in the residential, commercial, and industrial sectors used primarily for own-use generation, but which may also sell some power to the grid. Excludes off-grid photovoltaics and other generators not connected to the distribution or transmission systems.
[2]Includes electricity-only and combined heat and power plants whose primary business to sell electricity, or electricity and heat, to the public.
[3]Includes emissions from geothermal power and nonbiogenic emissions from municipal solid waste.
Note: Totals may not equal sum of components due to independent rounding. Data for 2007 are model results and may differ slightly from official EIA data reports.
Source: Energy Information Administration, AEO2009 National Energy Modeling System runs HCFOSS09.D121108A, AEO2009.D120908A, and LCFOSS09.D121608A.

Table D7. Key Results for Electric Power Sector Plant Capital Cost Cases
(Gigawatts, Unless Otherwise Noted)

Net Summer Capacity, Generation Consumption, and Emissions	2007	2020				2030			
		Falling Plant Costs	Reference	Frozen Plant Costs	High Plant Costs	Falling Plant Costs	Reference	Frozen Plant Costs	High Plant Costs
Capacity									
Pulverized Coal	310.7	324.1	324.0	324.1	324.0	348.3	345.6	335.5	324.4
Coal Gasification Combined-Cycle	0.5	3.0	3.0	3.0	3.0	13.1	6.9	6.0	3.0
Conventional Natural Gas Combined-Cycle	181.0	196.4	196.4	196.7	196.5	196.5	196.5	197.2	197.0
Advanced Natural Gas Combined-Cycle	0.0	8.9	6.3	8.4	6.4	39.8	41.1	53.6	56.0
Conventional Combustion Turbine	133.3	139.1	138.5	137.4	135.2	138.9	140.9	143.8	144.6
Advanced Combustion Turbine	0.0	20.1	17.3	14.9	14.1	60.2	60.1	59.5	63.5
Fuel Cells	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Nuclear	100.5	111.4	108.4	105.1	105.1	121.6	112.6	100.7	100.7
Oil and Natural Gas Steam	118.8	103.0	101.8	99.9	99.9	99.5	100.5	99.8	99.8
Renewable Sources/Pumped Storage	122.9	143.8	143.6	143.5	143.1	174.4	160.1	155.8	151.4
Distributed Generation	0.0	0.1	0.0	0.0	0.0	1.6	0.3	0.0	0.0
Combined Heat and Power[1]	27.8	47.2	47.3	47.3	47.4	61.6	62.6	63.0	63.4
Total	**995.6**	**1097.1**	**1086.6**	**1080.4**	**1074.7**	**1255.5**	**1227.2**	**1214.9**	**1203.9**
Cumulative Additions									
Pulverized Coal	0.0	16.6	16.6	16.6	16.6	40.9	38.2	28.0	17.0
Coal Gasification Combined-Cycle	0.0	1.4	1.4	1.4	1.4	11.5	5.4	4.4	1.4
Conventional Natural Gas Combined-Cycle	0.0	15.4	15.4	15.7	15.5	15.5	15.5	16.2	16.0
Advanced Natural Gas Combined-Cycle	0.0	8.9	6.3	8.4	6.4	39.8	41.1	53.6	56.0
Conventional Combustion Turbine	0.0	10.5	10.5	9.4	8.6	11.1	12.9	15.8	18.0
Advanced Combustion Turbine	0.0	20.1	17.3	14.9	14.1	60.2	60.1	59.5	63.5
Fuel Cells	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Nuclear	0.0	7.5	4.5	1.2	1.2	22.1	13.1	1.2	1.2
Oil and Natural Gas Steam	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Renewable Sources	0.0	21.1	20.9	20.8	20.4	51.7	37.4	33.1	28.7
Distributed Generation	0.0	0.1	0.0	0.0	0.0	1.6	0.3	0.0	0.0
Combined Heat and Power[1]	0.0	19.4	19.5	19.5	19.6	33.8	34.8	35.2	35.6
Total	**0.0**	**121.0**	**112.4**	**107.9**	**103.8**	**288.2**	**258.7**	**247.0**	**237.5**
Cumulative Retirements	**0.0**	**22.6**	**24.5**	**26.3**	**27.8**	**31.3**	**30.2**	**30.8**	**32.4**
Generation by Fuel (billion kilowatthours)									
Coal	2002	2123	2125	2125	2125	2425	2367	2282	2168
Petroleum	61	45	45	45	45	47	46	46	46
Natural Gas	814	784	801	817	817	773	880	1021	1103
Nuclear Power	806	884	862	840	840	979	907	817	817
Renewable Sources/Pumped Storage	319	550	549	550	549	657	615	604	596
Distributed Generation	0	0	0	0	0	1	0	0	0
Combined Heat and Power[1]	153	237	237	237	237	333	337	339	341
Total	**4155**	**4623**	**4618**	**4614**	**4614**	**5214**	**5153**	**5108**	**5071**
Fuel Consumption by the Electric Power Sector (quadrillion Btu)[2]									
Coal	20.84	22.00	22.01	22.01	22.01	24.67	24.25	23.52	22.55
Petroleum	0.67	0.51	0.51	0.51	0.51	0.53	0.53	0.52	0.52
Natural Gas	7.06	6.58	6.73	6.82	6.84	6.35	7.12	8.03	8.63
Nuclear Power	8.41	9.23	8.99	8.77	8.77	10.21	9.47	8.53	8.53
Renewable Sources	3.45	5.80	5.79	5.80	5.79	6.83	6.43	6.34	6.27
Total	**40.56**	**44.24**	**44.16**	**44.04**	**44.05**	**48.72**	**47.93**	**47.07**	**46.62**
Carbon Dioxide Emissions by the Electric Power Sector (million metric tons)[2]									
Coal	1980	2087	2089	2089	2089	2338	2299	2230	2139
Petroleum	66	39	40	40	40	41	41	40	40
Natural Gas	376	349	357	362	363	337	378	426	458
Other[3]	12	12	12	12	12	12	12	12	12
Total	**2433**	**2487**	**2497**	**2502**	**2503**	**2727**	**2729**	**2709**	**2649**
Average Electricity Price (cents per kilowatthour)	**9.1**	**9.3**	**9.4**	**9.4**	**9.5**	**9.9**	**10.4**	**10.7**	**10.9**

[1]Includes combined heat and power plants and electricity-only plants in the commercial and industrial sectors. Includes small on-site generating systems in the residential, commercial, and industrial sectors used primarily for own-use generation, but which may also sell some power to the grid. Excludes off-grid photovoltaics and other generators not connected to the distribution or transmission systems.
[2]Includes electricity-only and combined heat and power plants whose primary business to sell electricity, or electricity and heat, to the public.
[3]Includes emissions from geothermal power and nonbiogenic emissions from municipal solid waste.
Note: Totals may not equal sum of components due to independent rounding. Data for 2007 are model results and may differ slightly from official EIA data reports.
Source: Energy Information Administration, AEO2009 National Energy Modeling System runs DECCST09.D121108A, AEO2009.D120908A, FRZCST09.D121108a, and INCCST09.D121208A.

Table D8. Key Results for Greenhouse Gas Cases

Emissions, Prices, and Consumption	2007	2010			2020			2030		
		No GHG Concern	Reference	LW110	No GHG Concern	Reference	LW110	No GHG Concern	Reference	LW110
Greenhouse Gas Emissions (million metric tons carbon dioxide equivalent)										
Energy-related Carbon Dioxide	5990.8	5805.0	5801.4	5699.4	6044.5	5982.3	5436.0	6745.0	6414.4	4614.8
Other Covered Emissions	334.9	334.8	334.8	334.8	376.6	376.7	346.1	432.5	432.6	388.1
Total	**6325.7**	**6139.8**	**6136.2**	**6034.2**	**6421.1**	**6358.9**	**5782.2**	**7177.6**	**6847.0**	**5002.9**
Total Greenhouse Gas Emissions	7282.3	7120.4	7116.7	7014.7	7546.3	7483.9	6766.8	8501.7	8170.5	6177.9
Emissions Cap Assumed	- -	- -	- -	- -	- -	- -	4924.0	- -	- -	3860.0
Covered Emissions Net of Offsets	6368.8	6139.8	6136.2	6034.2	6421.1	6358.9	4671.8	7177.6	6847.0	3845.4
Difference (banking)	- -	- -	- -	- -	- -	- -	252.2	- -	- -	14.6
Emission Allowance Price (2007 dollars per metric ton carbon dioxide equivalent)	- -	- -	- -	- -	- -	- -	36.03	- -	- -	73.57
Energy Prices (2007 dollars per unit)										
Liquid Fuels (dollars per gallon)										
Transportation										
Motor Gasoline[1]	2.82	2.79	2.84	2.79	3.59	3.60	3.85	3.79	3.88	4.37
Jet Fuel[2]	2.17	2.11	2.16	2.11	2.97	2.99	3.30	3.24	3.32	3.95
Diesel[3]	2.87	2.69	2.75	2.69	3.54	3.57	3.87	3.80	3.92	4.53
Natural Gas (dollars per thousand cubic feet)										
Wellhead Price[4]	6.39	6.02	6.05	5.99	6.57	6.75	6.21	8.02	8.40	7.38
Residential	13.05	12.40	12.43	12.37	12.64	12.85	14.84	14.29	14.71	18.97
Electric Power[5]	7.22	6.74	6.77	6.70	7.15	7.35	9.01	8.47	8.94	12.51
Coal (dollars per million Btu)										
Minemouth[6]	1.27	1.44	1.44	1.43	1.41	1.39	1.38	1.54	1.46	1.38
Electric Power[5]	1.78	1.89	1.89	1.85	1.94	1.92	5.25	2.16	2.04	8.72
Electricity (cents per kilowatthour)	9.1	9.0	9.0	9.0	9.3	9.4	10.2	10.1	10.4	12.7
Energy Consumption (quadrillion Btu)										
Liquid Fuels and Other Petroleum[7]	40.75	37.93	37.89	37.91	38.97	38.93	38.35	41.66	41.60	39.87
Natural Gas	23.70	23.22	23.20	22.98	23.78	24.09	22.88	24.02	25.04	22.45
Coal[8]	22.74	22.90	22.91	21.93	24.80	23.98	20.30	30.62	26.56	16.40
Nuclear Power	8.41	8.45	8.45	8.45	8.77	8.99	9.36	8.58	9.47	12.21
Renewable/Other[9]	6.28	7.40	7.41	8.67	9.46	9.45	11.38	10.87	10.90	15.68
Total	**101.89**	**99.89**	**99.85**	**99.95**	**105.78**	**105.44**	**102.29**	**115.75**	**113.56**	**106.59**

[1]Sales weighted-average price for all grades. Includes Federal, State and local taxes.
[2]Includes only kerosene type.
[3]Diesel fuel for on-road use. Includes Federal and State taxes while excluding county and local taxes.
[4]Represents lower 48 onshore and offshore supplies.
[5]Includes electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public. Includes small power producers and exempt wholesale generators.
[6]Includes reported prices for both open market and captive mines.
[7]Includes petroleum-derived fuels and non-petroleum derived fuels, such as ethanol and biodiesel, and coal-based synthetic liquids. Petroleum coke, which is a solid, is included. Also included are natural gas plant liquids, crude oil consumed as a fuel, and liquid hydrogen.
[8]Excludes coal converted to coal-based synthetic liquids.
[9]Includes grid-connected electricity from landfill gas; municipal waste; wind; photovoltaic and solar thermal sources; and non-electric energy from renewable sources, such as active and passive solar systems. Includes net electricity imports.
- - = Not applicable.
GHG = Greenhouse gas.
Note: Totals may not equal sum of components due to independent rounding. Data for 2007 are model results and may differ slightly from official EIA data reports.
Source: Energy Information Administration, AEO2009 National Energy Modeling System runs NORSK2009.D120908A, AEO2009.D120908A, and CAP2009.D010909A.

Table D9. Key Results for Greenhouse Gas Cases
(Gigawatts, Unless Otherwise Noted)

Net Summer Capacity, Generation Consumption, and Emissions	2007	2010			2020			2030		
		No GHG Concern	Reference	LW110	No GHG Concern	Reference	LW110	No GHG Concern	Reference	LW110
Capacity										
Pulverized Coal	310.7	320.5	320.5	320.4	333.6	324.0	301.2	380.5	345.6	216.7
Coal Gasification Combined-Cycle	0.5	0.5	0.5	0.5	3.4	3.0	14.5	17.2	6.9	100.5
Conventional Natural Gas Combined-Cycle	181.0	194.8	194.8	194.8	196.3	196.4	196.6	196.6	196.5	196.8
Advanced Natural Gas Combined-Cycle	0.0	0.0	0.0	0.0	1.8	6.3	6.4	22.2	41.1	36.9
Conventional Combustion Turbine	133.3	140.7	140.6	138.9	137.3	138.5	134.5	138.3	140.9	134.4
Advanced Combustion Turbine	0.0	1.5	1.5	1.5	17.4	17.3	4.4	55.7	60.1	13.9
Fuel Cells	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Nuclear	100.5	101.2	101.2	101.2	105.1	108.4	113.0	101.4	112.6	146.3
Oil and Natural Gas Steam	118.8	118.4	118.4	118.4	102.6	101.8	94.9	100.6	100.5	91.7
Renewable Sources/Pumped Storage	122.9	136.8	137.0	145.4	143.4	143.6	154.4	156.4	160.1	225.7
Distributed Generation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.2	0.3	0.0
Combined Heat and Power[1]	27.8	32.5	32.6	32.4	49.1	47.3	46.6	75.4	62.6	61.9
Total	**995.6**	**1046.9**	**1047.1**	**1053.4**	**1090.0**	**1086.6**	**1066.4**	**1244.5**	**1227.2**	**1224.8**
Cumulative Additions										
Pulverized Coal	0.0	11.3	11.3	11.3	26.3	16.6	28.1	73.2	38.2	114.1
Coal Gasification Combined-Cycle	0.0	0.0	0.0	0.0	1.9	1.4	1.4	15.7	5.4	1.4
Conventional Natural Gas Combined-Cycle	0.0	13.8	13.8	13.8	15.3	15.4	17.7	15.6	15.5	33.1
Advanced Natural Gas Combined-Cycle	0.0	0.0	0.0	0.0	1.8	6.3	4.3	22.2	41.1	19.5
Conventional Combustion Turbine	0.0	7.7	7.6	5.9	9.0	10.5	5.9	10.0	12.9	6.0
Advanced Combustion Turbine	0.0	1.5	1.5	1.5	17.4	17.3	4.4	55.7	60.1	13.9
Fuel Cells	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Nuclear	0.0	0.0	0.0	0.0	1.2	4.5	9.1	1.9	13.1	46.8
Oil and Natural Gas Steam	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Renewable Sources	0.0	13.9	14.1	22.5	20.7	20.9	31.7	33.7	37.4	103.0
Distributed Generation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.2	0.3	0.0
Combined Heat and Power[1]	0.0	4.7	4.8	4.6	21.3	19.5	18.8	47.6	34.8	34.1
Total	**0.0**	**53.0**	**53.1**	**59.6**	**114.7**	**112.4**	**121.4**	**275.7**	**258.7**	**372.0**
Cumulative Retirements	**0.0**	**2.3**	**2.3**	**2.4**	**23.5**	**24.5**	**53.7**	**29.9**	**30.2**	**145.9**
Generation by Fuel (billion kilowatthours)										
Coal	2002	2037	2038	1944	2192	2125	1822	2633	2367	1600
Petroleum	61	43	43	43	45	45	42	48	46	40
Natural Gas	814	741	737	711	755	801	735	724	880	675
Nuclear Power	806	809	809	809	840	862	897	822	907	1170
Renewable Sources/Pumped Storage	319	415	415	538	551	549	715	613	615	927
Distributed Generation	0	0	0	0	0	0	0	0	0	0
Combined Heat and Power[1]	153	174	174	173	249	237	231	432	337	326
Total	**4155**	**4219**	**4217**	**4218**	**4632**	**4618**	**4442**	**5272**	**5153**	**4737**
Fuel Consumption by the Electric Power Sector (quadrillion Btu)[2]										
Coal	20.84	21.03	21.03	20.06	22.59	22.01	18.58	26.35	24.25	14.82
Petroleum	0.67	0.49	0.49	0.49	0.51	0.51	0.48	0.54	0.53	0.46
Natural Gas	7.06	6.45	6.42	6.22	6.41	6.73	6.25	6.05	7.12	5.74
Nuclear Power	8.41	8.45	8.45	8.45	8.77	8.99	9.36	8.58	9.47	12.21
Renewable Sources	3.45	4.41	4.42	5.68	5.80	5.79	7.51	6.47	6.43	10.28
Total	**40.56**	**40.95**	**40.94**	**41.02**	**44.22**	**44.16**	**42.31**	**48.11**	**47.93**	**43.63**
Carbon Dioxide Emissions by the Electric Power Sector (million metric tons)[2]										
Coal	1980	1994	1995	1903	2142	2089	1685	2494	2299	868
Petroleum	66	38	38	38	40	40	37	42	41	36
Natural Gas	376	342	341	330	340	357	325	321	378	260
Other[3]	12	12	12	12	12	12	12	12	12	13
Total	**2433**	**2386**	**2385**	**2282**	**2534**	**2497**	**2059**	**2869**	**2729**	**1176**

[1]Includes combined heat and power plants and electricity-only plants in the commercial and industrial sectors. Includes small on-site generating systems in the residential, commercial, and industrial sectors used primarily for own-use generation, but which may also sell some power to the grid. Excludes off-grid photovoltaics and other generators not connected to the distribution or transmission systems.
[2]Includes electricity-only and combined heat and power plants whose primary business to sell electricity, or electricity and heat, to the public.
[3]Includes emissions from geothermal power and nonbiogenic emissions from municipal solid waste.
GHG = Greenhouse gas.
Note: Totals may not equal sum of components due to independent rounding. Data for 2007 are model results and may differ slightly from official EIA data reports.
Source: Energy Information Administration, AEO2009 National Energy Modeling System runs NORSK2009.D120908A, AEO2009.D120908A, and CAP2009.D010909A.

Table D10. Key Results for Renewable Technology Cases

Capacity, Generation, and Emissions	2007	2010			2020			2030		
		High Renewable Cost	Reference	Low Renewable Cost	High Renewable Cost	Reference	Low Renewable Cost	High Renewable Cost	Reference	Low Renewable Cost
Net Summer Capacity (gigawatts)										
Electric Power Sector[1]										
Conventional Hydropower	76.72	76.73	76.73	76.73	77.02	77.02	77.16	77.20	77.58	78.54
Geothermal[2]	2.36	2.53	2.53	2.53	2.64	2.66	2.64	2.64	3.00	3.03
Municipal Waste[3]	3.43	3.97	4.04	4.04	4.06	4.12	4.07	4.15	4.15	4.07
Wood and Other Biomass[4]	2.18	2.20	2.20	2.20	3.97	4.22	5.58	5.00	8.86	27.00
Solar Thermal	0.53	0.54	0.54	0.54	0.81	0.81	0.81	0.86	0.86	0.86
Solar Photovoltaic	0.04	0.06	0.06	0.06	0.21	0.21	0.21	0.38	0.38	0.38
Wind	16.19	29.43	29.46	29.46	33.68	33.07	33.05	41.34	43.80	60.75
Total	**101.46**	**115.46**	**115.57**	**115.56**	**122.39**	**122.12**	**123.51**	**131.57**	**138.63**	**174.63**
End-Use Sector[5]										
Conventional Hydropower	0.70	0.70	0.70	0.70	0.70	0.70	0.70	0.70	0.70	0.70
Geothermal	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Municipal Waste[6]	0.34	0.34	0.34	0.34	0.34	0.34	0.34	0.34	0.34	0.34
Wood and Other Biomass	4.64	4.65	4.65	4.65	7.08	7.28	7.56	12.74	13.23	14.03
Solar Photovoltaic	0.43	1.73	1.73	1.74	8.81	9.72	12.45	9.25	11.78	17.50
Wind	0.04	0.04	0.04	0.04	0.07	0.09	0.12	0.24	0.31	0.70
Total	**6.15**	**7.45**	**7.45**	**7.46**	**17.00**	**18.12**	**21.16**	**23.27**	**26.35**	**33.26**
Generation (billion kilowatthours)										
Electric Power Sector[1]										
Coal	2002	2040	2038	2035	2129	2125	2121	2374	2367	2258
Petroleum	61	43	43	43	45	45	45	47	46	46
Natural Gas	814	738	737	737	801	801	797	883	880	871
Total Fossil	**2877**	**2820**	**2818**	**2816**	**2975**	**2970**	**2963**	**3304**	**3293**	**3175**
Conventional Hydropower	245.86	268.05	268.05	268.05	296.37	296.29	296.96	297.40	298.97	303.84
Geothermal	14.84	17.78	17.78	17.78	18.91	19.11	18.91	18.94	21.80	22.06
Municipal Waste[7]	14.42	18.71	19.30	19.30	19.45	19.95	19.50	20.15	20.17	19.50
Wood and Other Biomass[4]	10.38	26.35	28.07	30.80	113.21	117.82	130.90	131.41	140.44	261.52
Dedicated Plants	8.41	12.88	12.85	12.87	25.96	28.74	39.05	34.57	62.27	193.82
Cofiring	1.97	13.47	15.22	17.93	87.25	89.08	91.85	96.85	78.17	67.70
Solar Thermal	0.60	0.99	0.99	0.99	1.88	1.88	1.88	2.02	2.02	2.02
Solar Photovoltaic	0.01	0.14	0.14	0.14	0.49	0.49	0.49	0.94	0.94	0.94
Wind	32.14	80.39	80.50	80.49	94.62	92.45	93.20	120.48	129.38	188.34
Total Renewable	**318.25**	**412.42**	**414.82**	**417.54**	**544.94**	**547.99**	**561.84**	**591.34**	**613.71**	**798.22**
End-Use Sector[5]										
Total Fossil	101	110	110	110	141	141	140	195	194	192
Conventional Hydropower[8]	2.45	2.45	2.45	2.45	2.45	2.45	2.45	2.45	2.45	2.45
Geothermal	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Municipal Waste[6]	2.01	2.75	2.75	2.75	2.75	2.75	2.75	2.75	2.75	2.75
Wood and Other Biomass	28.13	28.19	28.20	28.22	46.00	47.17	48.82	87.93	90.81	95.83
Solar Photovoltaic	0.68	2.77	2.78	2.79	14.15	16.02	20.34	14.82	19.49	28.92
Wind	0.06	0.06	0.06	0.06	0.10	0.12	0.17	0.35	0.45	1.00
Total Renewable	**33.33**	**36.22**	**36.24**	**36.27**	**65.46**	**68.51**	**74.54**	**108.30**	**115.95**	**130.95**
Carbon Dioxide Emissions by the Electric Power Sector (million metric tons)[1]										
Coal	1979.7	1996.7	1995.0	1992.3	2091.9	2088.5	2083.4	2300.5	2299.0	2209.9
Petroleum	65.7	38.0	38.0	38.0	39.6	39.5	39.5	41.1	40.9	40.4
Natural Gas	376.5	341.2	340.7	341.0	357.1	356.9	355.4	378.3	377.9	375.0
Other[9]	11.6	11.6	11.6	11.6	11.7	11.7	11.7	11.7	11.7	11.7
Total	**2433.4**	**2387.5**	**2385.4**	**2382.9**	**2500.2**	**2496.6**	**2489.9**	**2731.5**	**2729.5**	**2637.1**

[1]Includes electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public.
[2]Includes hydrothermal resources only (hot water and steam).
[3]Includes all municipal waste, landfill gas, and municipal sewage sludge. Incremental growth is assumed to be for landfill gas facilities. All municipal waste is included, although a portion of the municipal waste stream contains petroleum-derived plastics and other non-renewable sources.
[4]Includes projections for energy crops after 2010.
[5]Includes combined heat and power plants and electricity-only plants in the commercial and industrial sectors; and small on-site generating systems in the residential, commercial, and industrial sectors used primarily for own-use generation, but which may also sell some power to the grid. Excludes off-grid photovoltaics and other generators not connected to the distribution or transmission systems.
[6]Includes municipal waste, landfill gas, and municipal sewage sludge. All municipal waste is included, although a portion of the municipal waste stream contains petroleum-derived plastics and other non-renewable sources.
[7]Includes biogenic municipal waste, landfill gas, and municipal sewage sludge. Incremental growth is assumed to be for landfill gas facilities.
[8]Represents own-use industrial hydroelectric power.
[9]Includes emissions from geothermal power and nonbiogenic emissions from municipal solid waste.
Note: Totals may not equal sum of components due to independent rounding. Data for 2007 are model results and may differ slightly from official EIA data reports.
Source: Energy Information Administration, AEO2009 National Energy Modeling System runs HIRENCST09.D011309B, AEO2009.D120908A, and LORENCST09.D011509B.

Table D11. Key Results for Production Tax Credit Case

Capacity, Generation, and Emissions	2007	2010		2020		2030	
		Reference	Production Tax Credit Extension	Reference	Production Tax Credit Extension	Reference	Production Tax Credit Extension
Net Summer Capacity (gigawatts)							
Electric Power Sector[1]							
Conventional Hydropower	76.72	76.73	76.73	77.02	77.03	77.58	77.47
Geothermal[2]	2.36	2.53	2.53	2.66	2.64	3.00	2.72
Municipal Waste[3]	3.43	4.04	3.81	4.12	4.09	4.15	4.14
Wood and Other Biomass[4]	2.18	2.20	2.20	4.22	4.67	8.86	9.18
Solar Thermal	0.53	0.54	0.54	0.81	0.81	0.86	0.86
Solar Photovoltaic	0.04	0.06	0.06	0.21	0.21	0.38	0.38
Wind	16.19	29.46	33.33	33.07	49.65	43.80	52.08
Total	**101.46**	**115.57**	**119.20**	**122.12**	**139.09**	**138.63**	**146.83**
End-Use Sector[5]							
Conventional Hydropower	0.70	0.70	0.70	0.70	0.70	0.70	0.70
Geothermal	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Municipal Waste[6]	0.34	0.34	0.34	0.34	0.34	0.34	0.34
Wood and Other Biomass	4.64	4.65	4.65	7.28	7.28	13.23	13.23
Solar Photovoltaic	0.43	1.73	1.73	9.72	9.72	11.78	11.76
Wind	0.04	0.04	0.04	0.09	0.09	0.31	0.31
Total	**6.15**	**7.45**	**7.45**	**18.12**	**18.12**	**26.35**	**26.33**
Generation (billion kilowatthours)							
Electric Power Sector[1]							
Coal	2002	2038	2039	2125	2137	2367	2360
Petroleum	61	43	43	45	45	46	46
Natural Gas	814	737	727	801	767	880	876
Total Fossil	**2877**	**2818**	**2809**	**2970**	**2948**	**3293**	**3283**
Conventional Hydropower	245.86	268.05	268.05	296.29	296.26	298.97	298.29
Geothermal	14.84	17.78	17.78	19.11	18.91	21.80	19.58
Municipal Waste[7]	14.42	19.30	17.48	19.95	19.65	20.17	20.11
Wood and Other Biomass[4]	10.38	28.07	26.51	117.82	97.83	140.44	138.81
Dedicated Plants	8.41	12.85	12.81	28.74	31.42	62.27	64.28
Cofiring	1.97	15.22	13.70	89.08	66.41	78.17	74.54
Solar Thermal	0.60	0.99	0.99	1.88	1.88	2.02	2.02
Solar Photovoltaic	0.01	0.14	0.14	0.49	0.49	0.94	0.94
Wind	32.14	80.50	93.73	92.45	149.09	129.38	157.85
Total Renewable	**318.25**	**414.82**	**424.68**	**547.99**	**584.11**	**613.71**	**637.60**
End-Use Sector[5]							
Total Fossil	101	110	110	141	141	194	193
Conventional Hydropower[8]	2.45	2.45	2.45	2.45	2.45	2.45	2.45
Geothermal	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Municipal Waste[6]	2.01	2.75	2.75	2.75	2.75	2.75	2.75
Wood and Other Biomass	28.13	28.20	28.20	47.17	47.18	90.81	90.86
Solar Photovoltaic	0.68	2.78	2.78	16.02	16.01	19.49	19.46
Wind	0.06	0.06	0.06	0.12	0.12	0.45	0.44
Total Renewable	**33.33**	**36.24**	**36.24**	**68.51**	**68.52**	**115.95**	**115.96**
Carbon Dioxide Emissions by the Electric Power Sector (million metric tons)[1]							
Coal	1979.7	1995.0	1995.4	2088.5	2098.8	2299.0	2292.5
Petroleum	65.7	38.0	38.0	39.5	39.4	40.9	40.8
Natural Gas	376.5	340.7	336.9	356.9	343.3	377.9	376.2
Other[9]	11.6	11.6	11.6	11.7	11.7	11.7	11.7
Total	**2433.4**	**2385.4**	**2381.9**	**2496.6**	**2493.2**	**2729.5**	**2721.1**

[1]Includes electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public.
[2]Includes hydrothermal resources only (hot water and steam).
[3]Includes all municipal waste, landfill gas, and municipal sewage sludge. Incremental growth is assumed to be for landfill gas facilities. All municipal waste is included, although a portion of the municipal waste stream contains petroleum-derived plastics and other non-renewable sources.
[4]Includes projections for energy crops after 2010.
[5]Includes combined heat and power plants and electricity-only plants in the commercial and industrial sectors; and small on-site generating systems in the residential, commercial, and industrial sectors used primarily for own-use generation, but which may also sell some power to the grid. Excludes off-grid photovoltaics and other generators not connected to the distribution or transmission systems.
[6]Includes municipal waste, landfill gas, and municipal sewage sludge. All municipal waste is included, although a portion of the municipal waste stream contains petroleum-derived plastics and other non-renewable sources.
[7]Includes biogenic municipal waste, landfill gas, and municipal sewage sludge. Incremental growth is assumed to be for landfill gas facilities.
[8]Represents own-use industrial hydroelectric power.
[9]Includes emissions from geothermal power and nonbiogenic emissions from municipal solid waste.
Note: Totals may not equal sum of components due to independent rounding. Data for 2007 are model results and may differ slightly from official EIA data reports.
Source: Energy Information Administration, AEO2009 National Energy Modeling System runs AEO2009.D120908A, and PTC09.D010709A.

Table D12. Natural Gas Supply and Disposition, Oil and Gas Technological Progress Cases
(Trillion Cubic Feet per Year, Unless Otherwise Noted)

Supply, Disposition, and Prices	2007	2010			2020			2030		
		Slow Technology	Reference	Rapid Technology	Slow Technology	Reference	Rapid Technology	Slow Technology	Reference	Rapid Technology
Natural Gas Prices										
(2007 dollars per million Btu)										
Henry Hub Spot Price	6.96	6.68	6.66	6.57	7.96	7.43	7.04	10.27	9.25	8.60
Average Lower 48 Wellhead Price[1]	6.22	5.90	5.88	5.81	7.03	6.56	6.22	9.07	8.17	7.59
(2007 dollars per thousand cubic feet)										
Average Lower 48 Wellhead Price[1]	6.39	6.06	6.05	5.97	7.23	6.75	6.39	9.33	8.40	7.81
Dry Gas Production[2]	**19.30**	**20.36**	**20.38**	**20.41**	**20.76**	**21.48**	**21.94**	**22.06**	**23.60**	**25.03**
Lower 48 Onshore	15.91	16.74	16.75	16.75	15.63	16.11	16.41	15.22	16.76	17.91
Associated-Dissolved	1.39	1.41	1.41	1.41	1.32	1.37	1.40	1.22	1.32	1.35
Non-Associated	14.51	15.33	15.34	15.34	14.30	14.74	15.00	14.00	15.44	16.56
Conventional	5.36	4.72	4.70	4.69	3.46	3.36	3.30	2.31	2.18	2.15
Unconventional	9.15	10.62	10.64	10.65	10.84	11.38	11.70	11.70	13.26	14.41
Gas Shale	1.17	2.26	2.31	2.31	2.54	2.97	3.05	3.36	4.15	4.48
Coalbed Methane	1.84	1.80	1.79	1.80	1.73	1.78	1.88	1.76	2.01	2.23
Tight Gas	6.15	6.56	6.54	6.54	6.57	6.62	6.78	6.57	7.10	7.70
Lower 48 Offshore	2.97	3.25	3.26	3.28	3.99	4.23	4.39	4.87	4.88	5.15
Associated-Dissolved	0.62	0.71	0.72	0.72	0.98	1.00	1.06	1.06	1.16	1.23
Non-Associated	2.35	2.53	2.55	2.56	3.01	3.23	3.34	3.81	3.72	3.92
Alaska	0.42	0.37	0.37	0.37	1.14	1.14	1.14	1.96	1.96	1.96
Supplemental Natural Gas[3]	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06
Net Imports	**3.79**	**2.51**	**2.50**	**2.49**	**2.01**	**1.86**	**1.83**	**0.91**	**0.66**	**0.84**
Pipeline[4]	3.06	2.03	2.02	2.02	0.56	0.48	0.50	-0.01	-0.18	0.03
Liquefied Natural Gas	0.73	0.48	0.47	0.47	1.46	1.38	1.33	0.92	0.85	0.80
Total Supply	**23.15**	**22.93**	**22.94**	**22.96**	**22.84**	**23.40**	**23.84**	**23.03**	**24.33**	**25.93**
Consumption by Sector										
Residential	4.72	4.78	4.79	4.79	4.92	4.96	4.99	4.86	4.93	4.97
Commercial	3.01	3.05	3.06	3.06	3.21	3.25	3.28	3.37	3.44	3.49
Industrial[5]	6.63	6.56	6.59	6.58	6.58	6.65	6.69	6.67	6.85	6.94
Electric Power[6]	6.87	6.26	6.25	6.27	6.16	6.54	6.85	6.04	6.93	8.25
Transportation[7]	0.02	0.03	0.03	0.03	0.07	0.07	0.07	0.09	0.09	0.09
Pipeline Fuel	0.62	0.62	0.62	0.62	0.66	0.67	0.68	0.67	0.70	0.73
Lease and Plant Fuel[8]	1.17	1.24	1.24	1.24	1.27	1.29	1.32	1.36	1.43	1.49
Total	**23.05**	**22.55**	**22.57**	**22.59**	**22.87**	**23.43**	**23.87**	**23.06**	**24.36**	**25.96**
Discrepancy[9]	**0.09**	**0.38**	**0.37**	**0.38**	**-0.03**	**-0.03**	**-0.03**	**-0.03**	**-0.03**	**-0.03**
Lower 48 End of Year Reserves	**225.18**	**229.03**	**230.11**	**231.42**	**200.96**	**213.14**	**222.92**	**184.54**	**211.98**	**233.91**

[1]Represents lower 48 onshore and offshore supplies.
[2]Marketed production (wet) minus extraction losses.
[3]Synthetic natural gas, propane air, coke oven gas, refinery gas, biomass gas, air injected for Btu stabilization, and manufactured gas commingled and distributed with natural gas.
[4]Includes any natural gas regasified in the Bahamas and transported via pipeline to Florida.
[5]Includes energy for combined heat and power plants, except those whose primary business is to sell electricity, or electricity and heat, to the public.
[6]Includes consumption of energy by electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public. Includes small power producers and exempt wholesale generators.
[7]Compressed natural gas used as a vehicle fuel.
[8]Represents natural gas used in field gathering and processing plant machinery.
[9]Balancing item. Natural gas lost as a result of converting flow data measured at varying temperatures and pressures to a standard temperature and pressure and the merger of different data reporting systems which vary in scope, format, definition, and respondent type. In addition, 2007 values include net storage injections.

Note: Totals may not equal sum of components due to independent rounding. Data for 2007 are model results and may differ slightly from official EIA data reports.

Sources: 2007 supply values: Energy Information Administration (EIA), *Natural Gas Monthly*, DOE/EIA-0130(2008/08) (Washington, DC, August 2008). 2007 consumption based on: EIA, *Annual Energy Review 2007*, DOE/EIA-0384(2007) (Washington, DC, June 2008). **Projections:** EIA, AEO2009 National Energy Modeling System runs OGLTEC09.D121408A, AEO2009.D120908A, and OGHTEC09.D121408A.

Table D13. Liquid Fuels Supply and Disposition, Oil and Gas Technological Progress Cases
(Million Barrels per Day, Unless Otherwise Noted)

Supply, Disposition, and Prices	2007	2010			2020			2030		
		Slow Technology	Reference	Rapid Technology	Slow Technology	Reference	Rapid Technology	Slow Technology	Reference	Rapid Technology
Prices (2007 dollars per barrel)										
Imported Low Sulfur Light Crude Oil[1]	**72.33**	**78.19**	**80.16**	**78.00**	**115.61**	**115.45**	**114.58**	**132.28**	**130.43**	**129.33**
Imported Crude Oil[1]	**63.83**	**75.49**	**77.56**	**75.23**	**112.58**	**112.05**	**109.31**	**126.43**	**124.60**	**119.51**
Crude Oil Supply										
Domestic Crude Oil Production[2]	5.07	5.58	5.62	5.65	6.12	6.48	6.73	6.65	7.37	7.71
Alaska	0.72	0.69	0.69	0.69	0.71	0.72	0.72	0.57	0.57	0.58
Lower 48 Onshore	2.91	2.90	2.92	2.94	3.16	3.37	3.52	3.47	4.06	4.18
Lower 48 Offshore	1.44	1.99	2.01	2.02	2.24	2.39	2.49	2.61	2.74	2.94
Net Crude Oil Imports	10.00	8.14	8.10	8.07	7.68	7.29	7.17	7.60	6.95	6.64
Other Crude Oil Supply	0.09	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total Crude Oil Supply	**15.16**	**13.72**	**13.72**	**13.73**	**13.80**	**13.77**	**13.90**	**14.26**	**14.32**	**14.34**
Other Petroleum Supply										
Natural Gas Plant Liquids	1.78	1.91	1.91	1.91	1.86	1.91	1.94	1.82	1.92	2.03
Net Petroleum Product Imports[3]	2.09	1.68	1.66	1.67	1.52	1.49	1.42	1.40	1.40	1.37
Refinery Processing Gain[4]	1.00	0.98	0.97	0.98	0.93	0.93	0.93	0.89	0.86	0.85
Other Supply[5]	0.74	1.22	1.22	1.22	1.97	1.98	1.98	3.10	3.08	3.07
Total Primary Supply[6]	**20.77**	**19.50**	**19.48**	**19.51**	**20.07**	**20.08**	**20.16**	**21.46**	**21.59**	**21.67**
Refined Petroleum Products Supplied										
Residential and Commercial	1.11	1.05	1.05	1.05	0.99	0.99	1.00	0.97	0.97	0.98
Industrial[7]	5.26	4.47	4.46	4.47	4.34	4.34	4.37	4.29	4.28	4.31
Transportation	14.25	13.97	13.96	13.98	14.64	14.65	14.70	16.08	16.18	16.21
Electric Power[8]	0.30	0.22	0.22	0.22	0.23	0.23	0.23	0.23	0.23	0.23
Total	**20.65**	**19.71**	**19.69**	**19.71**	**20.20**	**20.21**	**20.28**	**21.57**	**21.67**	**21.73**
Discrepancy[9]	**0.12**	**-0.21**	**-0.20**	**-0.21**	**-0.13**	**-0.13**	**-0.12**	**-0.11**	**-0.08**	**-0.06**
Lower 48 End of Year Reserves (billion barrels)[2]	**18.62**	**18.96**	**19.21**	**19.41**	**21.16**	**22.50**	**23.48**	**22.70**	**25.38**	**26.45**

[1]Weighted average price delivered to U.S. refiners.
[2]Includes lease condensate.
[3]Includes net imports of finished petroleum products, unfinished oils, other hydrocarbons, alcohols, ethers, and blending components.
[4]The volumetric amount by which total output is greater than input due to the processing of crude oil into products which, in total, have a lower specific gravity than the crude oil processed.
[5]Includes ethanol (including imports), alcohols, ethers, petroleum product stock withdrawals, domestic sources of blending components, other hydrocarbons, biodiesel (including imports), natural gas converted to liquid fuel, coal converted to liquid fuel, and biomass converted to liquid fuel.
[6]Total crude supply plus natural gas plant liquids, other inputs, refinery processing gain, and net product imports.
[7]Includes consumption for combined heat and power, which produces electricity and other useful thermal energy.
[8]Includes consumption of energy by electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public. Includes small power producers and exempt wholesale generators.
[9]Balancing item. Includes unaccounted for supply, losses and gains.
Note: Totals may not equal sum of components due to independent rounding. Data for 2007 are model results and may differ slightly from official EIA data reports.
Sources: 2007 product supplied data and imported crude oil price based on: Energy Information Administration (EIA), *Annual Energy Review 2007*, DOE/EIA-0384(2007) (Washington, DC, June 2008). 2007 imported low sulfur light crude oil price: EIA, Form EIA-856, "Monthly Foreign Crude Oil Acquisition Report." Other 2007 data: EIA, *Petroleum Supply Annual 2007,* DOE/EIA-0340(2007)/1 (Washington, DC, July 2008). **Projections:** EIA, AEO2009 National Energy Modeling System runs OGLTEC09.D121408A, AEO2009.D120908A, and OGHTEC09.D121408A.

Table D14. Natural Gas Supply and Disposition, OCS Limited Case

(Trillion Cubic Feet per Year, Unless Otherwise Noted)

Supply, Disposition, and Prices	2007	2010		2020		2030	
		Reference	OCS Limited	Reference	OCS Limited	Reference	OCS Limited
Natural Gas Prices							
(2007 dollars per million Btu)							
Henry Hub Spot Price	6.96	6.66	6.62	7.43	7.52	9.25	9.48
Average Lower 48 Wellhead Price[1]	6.22	5.88	5.85	6.56	6.64	8.17	8.38
(2007 dollars per thousand cubic feet)							
Average Lower 48 Wellhead Price[1]	6.39	6.05	6.01	6.75	6.83	8.40	8.61
Dry Gas Production[2]	**19.30**	**20.38**	**20.39**	**21.48**	**21.27**	**23.60**	**23.00**
Lower 48 Onshore	15.91	16.75	16.76	16.11	16.14	16.76	16.93
Associated-Dissolved	1.39	1.41	1.41	1.37	1.37	1.32	1.33
Non-Associated	14.51	15.34	15.35	14.74	14.77	15.44	15.60
Conventional	5.36	4.70	4.70	3.36	3.38	2.18	2.25
Unconventional	9.15	10.64	10.64	11.38	11.39	13.26	13.35
Gas Shale	1.17	2.31	2.31	2.97	2.97	4.15	4.22
Coalbed Methane	1.84	1.79	1.80	1.78	1.79	2.01	2.02
Tight Gas	6.15	6.54	6.54	6.62	6.63	7.10	7.11
Lower 48 Offshore	2.97	3.26	3.26	4.23	3.99	4.88	4.11
Associated-Dissolved	0.62	0.72	0.72	1.00	0.95	1.16	0.93
Non-Associated	2.35	2.55	2.55	3.23	3.04	3.72	3.18
Alaska	0.42	0.37	0.37	1.14	1.14	1.96	1.96
Supplemental Natural Gas[3]	0.06	0.06	0.06	0.06	0.06	0.06	0.06
Net Imports	**3.79**	**2.50**	**2.50**	**1.86**	**1.94**	**0.66**	**0.90**
Pipeline[4]	3.06	2.02	2.02	0.48	0.55	-0.18	0.04
Liquefied Natural Gas	0.73	0.47	0.47	1.38	1.40	0.85	0.86
Total Supply	**23.15**	**22.94**	**22.95**	**23.40**	**23.28**	**24.33**	**23.97**
Consumption by Sector							
Residential	4.72	4.79	4.79	4.96	4.95	4.93	4.91
Commercial	3.01	3.06	3.06	3.25	3.25	3.44	3.42
Industrial[5]	6.63	6.59	6.57	6.65	6.63	6.85	6.76
Electric Power[6]	6.87	6.25	6.27	6.54	6.47	6.93	6.74
Transportation[7]	0.02	0.03	0.03	0.07	0.07	0.09	0.09
Pipeline Fuel	0.62	0.62	0.62	0.67	0.67	0.70	0.71
Lease and Plant Fuel[8]	1.17	1.24	1.24	1.29	1.28	1.43	1.37
Total	**23.05**	**22.57**	**22.57**	**23.43**	**23.31**	**24.36**	**24.00**
Discrepancy[9]	**0.09**	**0.37**	**0.38**	**-0.03**	**-0.03**	**-0.03**	**-0.03**
Lower 48 End of Year Reserves	**225.18**	**230.11**	**230.00**	**213.14**	**211.41**	**211.98**	**209.17**

[1]Represents lower 48 onshore and offshore supplies.
[2]Marketed production (wet) minus extraction losses.
[3]Synthetic natural gas, propane air, coke oven gas, refinery gas, biomass gas, air injected for Btu stabilization, and manufactured gas commingled and distributed with natural gas.
[4]Includes any natural gas regasified in the Bahamas and transported via pipeline to Florida.
[5]Includes energy for combined heat and power plants, except those whose primary business is to sell electricity, or electricity and heat, to the public.
[6]Includes consumption of energy by electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public. Includes small power producers and exempt wholesale generators.
[7]Compressed natural gas used as a vehicle fuel.
[8]Represents natural gas used in field gathering and processing plant machinery.
[9]Balancing item. Natural gas lost as a result of converting flow data measured at varying temperatures and pressures to a standard temperature and pressure and the merger of different data reporting systems which vary in scope, format, definition, and respondent type. In addition, 2007 values include net storage injections.
OCS = Outer continental shelf.
Note: Totals may not equal sum of components due to independent rounding. Data for 2007 are model results and may differ slightly from official EIA data reports.
Sources: 2007 supply values: Energy Information Administration (EIA), *Natural Gas Monthly*, DOE/EIA-0130(2008/08) (Washington, DC, August 2008). 2007 consumption based on: EIA, *Annual Energy Review 2007*, DOE/EIA-0384(2007) (Washington, DC, June 2008). **Projections:** EIA, AEO2009 National Energy Modeling System runs AEO2009.D120908A and OCSLIMITED.D120908A.

Table D15. Liquid Fuels Supply and Disposition, OCS Limited Case
(Million Barrels per Day, Unless Otherwise Noted)

Supply, Disposition, and Prices	2007	2010		2020		2030	
		Reference	OCS Limited	Reference	OCS Limited	Reference	OCS Limited
Prices (2007 dollars per barrel)							
Imported Low Sulfur Light Crude Oil[1]	**72.33**	**80.16**	**78.10**	**115.45**	**115.56**	**130.43**	**131.76**
Imported Crude Oil[1]	**63.83**	**77.56**	**75.40**	**112.05**	**112.90**	**124.60**	**126.08**
Crude Oil Supply							
Domestic Crude Oil Production[2]	5.07	5.62	5.61	6.48	6.21	7.37	6.83
Alaska	0.72	0.69	0.69	0.72	0.72	0.57	0.58
Lower 48 Onshore	2.91	2.92	2.92	3.37	3.36	4.06	4.07
Lower 48 Offshore	1.44	2.01	2.01	2.39	2.12	2.74	2.17
Net Crude Oil Imports	10.00	8.10	8.11	7.29	7.58	6.95	7.44
Other Crude Oil Supply	0.09	0.00	0.00	0.00	0.00	0.00	0.00
Total Crude Oil Supply	**15.16**	**13.72**	**13.72**	**13.77**	**13.78**	**14.32**	**14.27**
Other Petroleum Supply							
Natural Gas Plant Liquids	1.78	1.91	1.91	1.91	1.90	1.92	1.92
Net Petroleum Product Imports[3]	2.09	1.66	1.67	1.49	1.51	1.40	1.40
Refinery Processing Gain[4]	1.00	0.97	0.98	0.93	0.93	0.86	0.86
Other Supply[5]	0.74	1.22	1.22	1.98	1.97	3.08	3.07
Total Primary Supply[6]	**20.77**	**19.48**	**19.50**	**20.08**	**20.09**	**21.59**	**21.51**
Refined Petroleum Products Supplied							
Residential and Commercial	1.11	1.05	1.05	0.99	0.99	0.97	0.97
Industrial[7]	5.26	4.46	4.47	4.34	4.34	4.28	4.29
Transportation	14.25	13.96	13.97	14.65	14.66	16.18	16.10
Electric Power[8]	0.30	0.22	0.22	0.23	0.23	0.23	0.23
Total	**20.65**	**19.69**	**19.71**	**20.21**	**20.22**	**21.67**	**21.59**
Discrepancy[9]	**0.12**	**-0.20**	**-0.21**	**-0.13**	**-0.13**	**-0.08**	**-0.08**
Lower 48 End of Year Reserves (billion barrels)[2]	**18.62**	**19.21**	**19.18**	**22.50**	**21.32**	**25.38**	**23.32**

[1]Weighted average price delivered to U.S. refiners.
[2]Includes lease condensate.
[3]Includes net imports of finished petroleum products, unfinished oils, other hydrocarbons, alcohols, ethers, and blending components.
[4]The volumetric amount by which total output is greater than input due to the processing of crude oil into products which, in total, have a lower specific gravity than the crude oil processed.
[5]Includes ethanol (including imports), alcohols, ethers, petroleum product stock withdrawals, domestic sources of blending components, other hydrocarbons, biodiesel (including imports), natural gas converted to liquid fuel, coal converted to liquid fuel, and biomass converted to liquid fuel.
[6]Total crude supply plus natural gas plant liquids, other inputs, refinery processing gain, and net product imports.
[7]Includes consumption for combined heat and power, which produces electricity and other useful thermal energy.
[8]Includes consumption of energy by electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public. Includes small power producers and exempt wholesale generators.
[9]Balancing item. Includes unaccounted for supply, losses and gains.
OCS = Outer continental shelf.
Note: Totals may not equal sum of components due to independent rounding. Data for 2007 are model results and may differ slightly from official EIA data reports.
Sources: 2007 product supplied data and imported crude oil price based on: Energy Information Administration (EIA), *Annual Energy Review 2007*, DOE/EIA-0384(2007) (Washington, DC, June 2008). 2007 imported low sulfur light crude oil price: EIA, Form EIA-856, “Monthly Foreign Crude Oil Acquisition Report.” Other 2007 data: EIA, *Petroleum Supply Annual 2007,* DOE/EIA-0340(2007)/1 (Washington, DC, July 2008). **Projections:** EIA, AEO2009 National Energy Modeling System runs AEO2009.D120908A and OCSLIMITED.D120908A.

Table D16. Natural Gas Supply and Disposition, Liquefied Natural Gas Supply Cases
(Trillion Cubic Feet per Year, Unless Otherwise Noted)

Supply, Disposition, and Prices	2007	2010			2020			2030		
		Low LNG	Reference	High LNG	Low LNG	Reference	High LNG	Low LNG	Reference	High LNG
Dry Gas Production[1]	**19.30**	**20.46**	**20.38**	**20.39**	**21.93**	**21.48**	**19.92**	**23.84**	**23.60**	**22.00**
Lower 48 Onshore	15.91	16.81	16.75	16.76	16.46	16.11	14.92	16.93	16.76	15.35
Associated-Dissolved	1.39	1.41	1.41	1.41	1.37	1.37	1.37	1.32	1.32	1.32
Non-Associated	14.51	15.40	15.34	15.34	15.10	14.74	13.55	15.61	15.44	14.02
Conventional	5.36	4.72	4.70	4.70	3.44	3.36	3.10	2.17	2.18	2.09
Unconventional	9.15	10.67	10.64	10.64	11.66	11.38	10.45	13.43	13.26	11.94
Gas Shale	1.17	2.32	2.31	2.31	3.08	2.97	2.66	4.25	4.15	3.43
Coalbed Methane	1.84	1.80	1.79	1.79	1.81	1.78	1.67	2.02	2.01	1.92
Tight Gas	6.15	6.56	6.54	6.54	6.77	6.62	6.13	7.16	7.10	6.58
Lower 48 Offshore	2.97	3.28	3.26	3.27	4.32	4.23	3.86	4.94	4.88	4.69
Associated-Dissolved	0.62	0.72	0.72	0.72	1.02	1.00	1.00	1.17	1.16	1.03
Non-Associated	2.35	2.56	2.55	2.55	3.30	3.23	2.86	3.78	3.72	3.66
Alaska	0.42	0.37	0.37	0.37	1.14	1.14	1.14	1.96	1.96	1.96
Supplemental Natural Gas[2]	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06
Net Imports	**3.79**	**2.41**	**2.50**	**2.50**	**1.17**	**1.86**	**4.14**	**0.39**	**0.66**	**3.65**
Pipeline[3]	3.06	2.03	2.02	2.03	0.76	0.48	-0.02	-0.02	-0.18	-0.57
Liquefied Natural Gas	0.73	0.37	0.47	0.47	0.41	1.38	4.15	0.41	0.85	4.22
Total Supply	**23.15**	**22.93**	**22.94**	**22.95**	**23.16**	**23.40**	**24.13**	**24.30**	**24.33**	**25.71**
Consumption by Sector										
Residential	4.72	4.79	4.79	4.79	4.94	4.96	5.03	4.93	4.93	4.98
Commercial	3.01	3.06	3.06	3.06	3.23	3.25	3.33	3.44	3.44	3.48
Industrial[4]	6.63	6.55	6.59	6.57	6.55	6.65	6.83	6.81	6.85	7.06
Electric Power[5]	6.87	6.26	6.25	6.27	6.43	6.54	7.00	6.93	6.93	8.08
Transportation[6]	0.02	0.03	0.03	0.03	0.07	0.07	0.07	0.09	0.09	0.09
Pipeline Fuel	0.62	0.62	0.62	0.62	0.66	0.67	0.66	0.69	0.70	0.70
Lease and Plant Fuel[7]	1.17	1.24	1.24	1.24	1.32	1.29	1.23	1.44	1.43	1.35
Total	**23.05**	**22.55**	**22.57**	**22.57**	**23.19**	**23.43**	**24.16**	**24.33**	**24.36**	**25.74**
Discrepancy[8]	**0.09**	**0.38**	**0.37**	**0.38**	**-0.03**	**-0.03**	**-0.03**	**-0.03**	**-0.03**	**-0.03**
Lower 48 End of Year Reserves	**225.18**	**229.99**	**230.11**	**229.92**	**215.76**	**213.14**	**207.10**	**214.22**	**211.98**	**195.62**
Natural Gas Prices										
(2007 dollars per million Btu)										
Henry Hub Spot Price	6.96	6.64	6.66	6.62	7.65	7.43	6.44	9.18	9.25	8.84
Average Lower 48 Wellhead Price[11]	6.22	5.87	5.88	5.85	6.76	6.56	5.69	8.11	8.17	7.80
(2007 dollars per thousand cubic feet)										
Average Lower 48 Wellhead Price[11]	6.39	6.03	6.05	6.01	6.94	6.75	5.85	8.33	8.40	8.02
Delivered Prices										
(2007 dollars per thousand cubic feet)										
Residential	13.05	12.42	12.43	12.40	13.04	12.85	11.91	14.64	14.71	14.30
Commercial	11.30	10.83	10.84	10.81	11.63	11.44	10.50	13.24	13.32	12.90
Industrial[4]	7.73	7.10	7.10	7.07	7.87	7.69	6.76	9.27	9.33	8.96
Electric Power[5]	7.22	6.76	6.77	6.74	7.53	7.35	6.52	8.90	8.94	8.73
Transportation[10]	15.89	15.31	15.32	15.29	15.51	15.31	14.45	16.62	16.70	16.33
Average[11]	**9.26**	**8.79**	**8.80**	**8.76**	**9.57**	**9.37**	**8.43**	**10.99**	**11.05**	**10.61**

[1]Marketed production (wet) minus extraction losses.
[2]Synthetic natural gas, propane air, coke oven gas, refinery gas, biomass gas, air injected for Btu stabilization, and manufactured gas commingled and distributed with natural gas.
[3]Includes any natural gas regasified in the Bahamas and transported via pipeline to Florida.
[4]Includes energy for combined heat and power plants, except those whose primary business is to sell electricity, or electricity and heat, to the public.
[5]Includes consumption of energy by electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public. Includes small power producers and exempt wholesale generators.
[6]Compressed natural gas used as vehicle fuel.
[7]Represents natural gas used in field gathering and processing plant machinery.
[8]Balancing item. Natural gas lost as a result of converting flow data measured at varying temperatures and pressures to a standard temperature and pressure and the merger of different data reporting systems which vary in scope, format, definition, and respondent type. In addition, 2007 values include net storage injections.
[9]Represents lower 48 onshore and offshore supplies.
[10]Compressed natural gas used as a vehicle fuel. Price includes estimated motor vehicle fuel taxes and estimated dispensing costs or charges.
[11]Weighted average prices. Weights used are the sectoral consumption values excluding lease, plant, and pipeline fuel.
LNG = Liquefied natural gas.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Data for 2007 are model results and may differ slightly from official EIA data reports.
Sources: 2007 supply values: Energy Information Administration (EIA), *Natural Gas Monthly*, DOE/EIA-0130(2008/08) (Washington, DC, August 2008). 2007 consumption based on: EIA, *Annual Energy Review 2007*, DOE/EIA-0384(2007) (Washington, DC, June 2008). **Projections:** EIA, AEO2009 National Energy Modeling System runs LOLNG09.D121408A, AEO2009.D120908A, and HILNG09.D121408A.

Table D17. Petroleum Supply and Disposition, ANWR Drilling Case
(Million Barrels per Day, Unless Otherwise Noted)

Supply, Disposition, and Prices	2007	2010		2020		2030	
		Reference	ANWR	Reference	ANWR	Reference	ANWR
Crude Oil							
Domestic Crude Production[1]	5.07	5.62	5.61	6.48	6.57	7.37	8.08
Alaska	0.72	0.69	0.69	0.72	0.83	0.57	1.30
Lower 48 States	4.35	4.93	4.93	5.76	5.74	6.80	6.78
Net Imports	10.00	8.10	8.11	7.29	7.22	6.95	6.22
Other Crude Supply[2]	0.09	0.00	0.00	0.00	0.00	0.00	0.00
Total Crude Supply	**15.16**	**13.72**	**13.72**	**13.77**	**13.80**	**14.32**	**14.31**
Other Supply							
Natural Gas Plant Liquids	1.78	1.91	1.91	1.91	1.91	1.92	1.97
Net Product Imports[3]	2.09	1.66	1.68	1.49	1.50	1.40	1.38
Refinery Processing Gain[4]	1.00	0.97	0.98	0.93	0.93	0.86	0.89
Ethanol[5]	0.45	0.84	0.84	1.28	1.28	1.91	1.91
Biodiesel[5]	0.03	0.06	0.06	0.10	0.10	0.13	0.13
Liquids from Coal	0.00	0.00	0.00	0.10	0.10	0.26	0.26
Liquids from Biomass	0.00	0.00	0.00	0.07	0.07	0.33	0.33
Other[6]	0.26	0.32	0.32	0.42	0.41	0.45	0.45
Total Primary Supply[7]	**20.77**	**19.48**	**19.50**	**20.08**	**20.12**	**21.59**	**21.62**
Refined Petroleum Products Supplied							
by Fuel							
Liquefied Petroleum Gases	2.09	1.99	2.00	1.82	1.82	1.74	1.75
E85[8]	0.00	0.00	0.00	0.58	0.58	1.50	1.50
Motor Gasoline[9]	9.29	9.34	9.35	8.60	8.61	8.04	8.01
Jet Fuel[10]	1.62	1.45	1.45	1.65	1.65	1.99	1.99
Distillate Fuel Oil[11]	4.20	4.08	4.09	4.62	4.62	5.42	5.43
Residual Fuel Oil	0.72	0.63	0.63	0.70	0.70	0.72	0.72
Other[12]	2.74	2.19	2.19	2.24	2.25	2.25	2.26
by Sector							
Residential and Commercial	1.11	1.05	1.05	0.99	1.00	0.97	0.98
Industrial[13]	5.26	4.46	4.47	4.34	4.35	4.28	4.30
Transportation	14.25	13.96	13.97	14.65	14.67	16.18	16.16
Electric Power[14]	0.30	0.22	0.22	0.23	0.23	0.23	0.23
Total	**20.65**	**19.69**	**19.71**	**20.21**	**20.24**	**21.67**	**21.66**
Discrepancy[15]	**0.12**	**-0.20**	**-0.21**	**-0.13**	**-0.12**	**-0.08**	**-0.04**
Imported Low Sulfur Light Crude Oil Price (2007 dollars per barrel)[16]	72.33	80.16	78.10	115.45	115.06	130.43	128.31
Imported Crude Oil Price (2007 dollars per barrel)[16]	63.83	77.56	75.41	112.05	111.60	124.60	121.74
Import Share of Product Supplied (percent)	58.3	50.1	50.1	44.0	43.6	40.9	37.4
Net Expenditures for Imported Crude Oil and Petroleum Products (billion 2007 dollars)	280.13	261.60	254.68	344.32	340.35	376.65	336.39

[1]Includes lease condensate.
[2]Strategic petroleum reserve stock additions plus unaccounted for crude oil and crude stock withdrawals minus crude product supplied.
[3]Includes other hydrocarbons and alcohols.
[4]The volumetric amount by which total output is greater than input due to the processing of crude oil into products which, in total, have a lower specific gravity than the crude oil processed.
[5]Includes net imports.
[6]Includes petroleum product stock withdrawals; domestic sources of blending components, other hydrocarbons, alcohols, and ethers.
[7]Total crude supply plus all components of Other Supply.
[8]E85 refers to a blend of 85 percent ethanol (renewable) and 15 percent motor gasoline (nonrenewable). To address cold starting issues, the percentage of ethanol varies seasonally. The annual average ethanol content of 74 percent is used for this forecast.
[9]Includes ethanol and ethers blended into gasoline.
[10]Includes only kerosene type.
[11]Includes distillate and kerosene.
[12]Includes aviation gasoline, petrochemical feedstocks, lubricants, waxes, asphalt, road oil, still gas, special naphthas, petroleum coke, crude oil product supplied, and miscellaneous petroleum products.
[13]Includes consumption for combined heat and power, which produces electricity and other useful thermal energy.
[14]Includes consumption of energy by electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public. Includes small power producers and exempt wholesale generators.
[15]Balancing item. Includes unaccounted for supply, losses, and gains.
[16]Weighted average price delivered to U.S. refiners.
ANWR = Arctic National Wildlife Refuge.
Note: Totals may not equal sum of components due to independent rounding. Data for 2007 are model results and may differ slightly from official EIA data reports.
Sources: 2007 imported crude oil price and petroleum product supplied based on: Energy Information Administration (EIA), *Annual Energy Review 2007*, DOE/EIA-0384(2007) (Washington, DC, June 2008). 2007 imported low sulfur light crude oil price: EIA, Form EIA-856, "Monthly Foreign Crude Oil Acquisition Report." Other 2007 data: EIA, *Petroleum Supply Annual 2007,* DOE/EIA-0340(2007)/1 (Washington, DC, July 2008). **Projections:** EIA, AEO2009 National Energy Modeling System runs AEO2009.D120908A and ANWR2009.D120908A.

Table D18. Key Results for Coal Cost Cases
(Million Short Tons per Year, Unless Otherwise Noted)

Supply, Disposition, and Prices	2007	2015			2030			Growth Rate, 2007-2030		
		Low Coal Cost	Reference	High Coal Cost	Low Coal Cost	Reference	High Coal Cost	Low Coal Cost	Reference	High Coal Cost
Production[1]	**1147**	**1218**	**1206**	**1172**	**1482**	**1341**	**1076**	**1.1%**	**0.7%**	**-0.3%**
Appalachia	378	350	343	341	403	353	344	0.3%	-0.3%	-0.4%
Interior	147	185	192	211	229	252	267	1.9%	2.4%	2.6%
West	621	682	671	619	849	735	464	1.4%	0.7%	-1.3%
Waste Coal Supplied[2]	**14**	**13**	**13**	**13**	**12**	**13**	**20**	**-0.9%**	**-0.4%**	**1.5%**
Net Imports[3]	**-25**	**-36**	**-28**	**-15**	**-38**	**10**	**75**	**1.9%**	**- -**	**- -**
Total Supply[4]	**1136**	**1195**	**1192**	**1170**	**1455**	**1363**	**1171**	**1.1%**	**0.8%**	**0.1%**
Consumption by Sector										
Residential and Commercial	4	3	3	3	3	3	3	-0.4%	-0.4%	-0.4%
Coke Plants	23	20	20	20	19	18	18	-0.8%	-1.0%	-1.0%
Other Industrial[5]	57	56	56	56	56	57	55	-0.0%	-0.0%	-0.1%
Coal-to-Liquids Heat and Power	0	10	9	9	40	38	35	- -	- -	- -
Coal-to-Liquids Liquids Production	0	8	8	8	34	32	29	- -	- -	- -
Electric Power[6]	1046	1097	1096	1074	1303	1215	1030	1.0%	0.7%	-0.1%
Total Coal Use	**1129**	**1195**	**1192**	**1170**	**1455**	**1363**	**1170**	**1.1%**	**0.8%**	**0.2%**
Average Minemouth Price[7]										
(2007 dollars per short ton)	25.82	24.18	28.71	35.11	15.63	29.10	60.12	-2.2%	0.5%	3.7%
(2007 dollars per million Btu)	1.27	1.19	1.42	1.73	0.78	1.46	2.92	-2.1%	0.6%	3.7%
Delivered Prices[8]										
(2007 dollars per short ton)										
Coke Plants	94.97	101.37	115.38	129.63	76.98	115.57	196.08	-0.9%	0.9%	3.2%
Other Industrial[5]	54.42	49.65	55.54	62.83	37.90	57.22	88.60	-1.6%	0.2%	2.1%
Coal to Liquids	- -	14.57	17.14	20.87	8.94	20.96	47.60	- -	- -	- -
Electric Power[6]										
(2007 dollars per short ton)	35.45	33.56	38.47	45.12	25.52	40.61	70.73	-1.4%	0.6%	3.0%
(2007 dollars per million Btu)	1.78	1.69	1.94	2.27	1.28	2.04	3.42	-1.4%	0.6%	2.9%
Average	**37.60**	**35.21**	**40.30**	**47.09**	**25.83**	**41.30**	**72.24**	**-1.6%**	**0.4%**	**2.9%**
Exports[9]	70.25	78.99	88.70	97.22	63.79	80.02	150.83	-0.4%	0.6%	3.4%
Cumulative Electricity Generating Capacity Additions (gigawatts)[10]										
Coal	0.0	17.8	17.8	17.8	75.5	47.5	22.6	- -	- -	- -
Conventional	0.0	15.6	15.6	15.6	61.3	37.2	15.6	- -	- -	- -
Advanced without Sequestration	0.0	2.2	2.2	2.2	13.2	9.3	6.0	- -	- -	- -
Advanced with Sequestration	0.0	0.0	0.0	0.0	1.0	1.0	1.0			
Petroleum	0.0	1.3	1.3	1.3	1.4	1.4	1.4	- -	- -	- -
Natural Gas	0.0	30.5	30.4	29.9	125.3	136.9	146.2	- -	- -	- -
Nuclear	0.0	1.2	1.2	1.2	5.4	13.1	16.7	- -	- -	- -
Renewables[11]	0.0	24.0	23.5	23.9	58.0	57.6	56.5	- -	- -	- -
Other	0.0	2.3	2.2	2.3	2.3	2.3	2.3	- -	- -	- -
Total	**0.0**	**77.1**	**76.5**	**76.4**	**267.9**	**258.7**	**245.8**			
Liquids from Coal (million barrels per day)	0.00	0.06	0.06	0.06	0.26	0.26	0.26	- -	- -	- -

Table D18. Key Results for Coal Cost Cases (Continued)
(Million Short Tons per Year, Unless Otherwise Noted)

Supply, Disposition, and Prices	2007	2015			2030			Growth Rate, 2007-2030		
		Low Coal Cost	Reference	High Coal Cost	Low Coal Cost	Reference	High Coal Cost	Low Coal Cost	Reference	High Coal Cost
Cost Indices										
(constant dollar index, 2007=1.000)										
Transportation Rate Multipliers										
Eastern Railroads	1.000	0.990	1.064	1.140	0.780	1.044	1.300	-1.1%	0.2%	1.1%
Western Railroads	1.000	1.010	1.082	1.160	0.890	1.183	1.480	-0.5%	0.7%	1.7%
Mine Equipment Costs										
Underground	1.000	1.008	1.071	1.136	0.867	1.071	1.319	-0.6%	0.3%	1.2%
Surface	1.000	0.948	1.007	1.069	0.815	1.007	1.241	-0.9%	0.0%	0.9%
Other Mine Supply Costs										
East of the Mississippi: All Mines	1.000	1.130	1.201	1.275	0.902	1.114	1.373	-0.4%	0.5%	1.4%
West of the Mississippi: Underground	1.000	1.130	1.201	1.275	0.902	1.114	1.373	-0.4%	0.5%	1.4%
West of the Mississippi: Surface	1.000	0.962	1.022	1.085	0.768	0.948	1.168	-1.1%	-0.2%	0.7%
Coal Mining Labor Productivity (short tons per miner per hour)	6.27	7.66	6.25	4.89	12.61	6.02	2.33	3.1%	-0.2%	-4.2%
Average Coal Miner Wage (2007 dollars per hour)	21.96	20.66	21.96	23.32	17.79	21.96	27.05	-0.9%	0.0%	0.9%

[1]Includes anthracite, bituminous coal, subbituminous coal, and lignite.
[2]Includes waste coal consumed by the electric power and industrial sectors. Waste coal supplied is counted as a supply-side item to balance the same amount of waste coal included in the consumption data.
[3]Excludes imports to Puerto Rico and the U.S. Virgin Islands.
[4]Production plus waste coal supplied plus net imports.
[5]Includes consumption for combined heat and power plants, except those plants whose primary business is to sell electricity, or electricity and heat, to the public. Excludes all coal use in the coal to liquids process.
[6]Includes all electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public.
[7]Includes reported prices for both open market and captive mines.
[8]Prices weighted by consumption tonnage; weighted average excludes residential and commercial prices, and export free-alongside-ship (f.a.s.) prices.
[9]F.a.s. price at U.S. port of exit.
[10]Cumulative additions after December 31, 2007. Includes all additions of electricity only and combined heat and power plants projected for the electric power, industrial, and commercial sectors.
[11]Includes conventional hydroelectric, geothermal, wood, wood waste, municipal waste, landfill gas, other biomass, solar, and wind power. Facilities co-firing biomass and coal are classified as coal.
- - = Not applicable.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Data for 2007 are model results and may differ slightly from official EIA data reports.
Sources: 2007 data based on: Energy Information Administration (EIA), *Annual Coal Report 2007*, DOE/EIA-0584(2007) (Washington, DC, September 2008); EIA, *Quarterly Coal Report, October-December 2007*, DOE/EIA-0121(2007/4Q) (Washington, DC, March 2008); U.S. Department of Labor, Bureau of Labor Statistics, Average Hourly Earnings of Production Workers: Coal Mining, Series ID : ceu1021210008; and EIA, AEO2009 National Energy Modeling System run AEO2009.D120908A. **Projections:** EIA, AEO2009 National Energy Modeling System runs LCCST09.D121608A, AEO2009.D120908A, and HCCST09.D121608A.

NEMS Overview and Brief Description of Cases

The National Energy Modeling System

The projections in the *Annual Energy Outlook 2009* (*AEO2009*) are generated from the National Energy Modeling System (NEMS) [*1*], developed and maintained by the Office of Integrated Analysis and Forecasting (OIAF) of the Energy Information Administration (EIA). In addition to its use in developing the *Annual Energy Outlook* (*AEO*) projections, NEMS is also used in analytical studies for the U.S. Congress, the Executive Office of the President, other offices within the U.S. Department of Energy (DOE), and other Federal agencies. The *AEO* projections are also used by analysts and planners in other government agencies and nongovernment organizations.

The projections in NEMS are developed with the use of a market-based approach to energy analysis. For each fuel and consuming sector, NEMS balances energy supply and demand, accounting for economic competition among the various energy fuels and sources. The time horizon of NEMS is the period through 2030, approximately 25 years into the future [*2*]. In order to represent regional differences in energy markets, the component modules of NEMS function at the regional level: the nine Census divisions for the end-use demand modules; production regions specific to oil, natural gas, and coal supply and distribution; the North American Electric Reliability Council regions and subregions for electricity; and the Petroleum Administration for Defense Districts (PADDs) for refineries.

NEMS is organized and implemented as a modular system. The modules represent each of the fuel supply markets, conversion sectors, and end-use consumption sectors of the energy system. NEMS also includes macroeconomic and international modules. The primary flows of information among the modules are the delivered prices of energy to end users and the quantities consumed, by product, region, and sector. The delivered fuel prices encompass all the activities necessary to produce, import, and transport fuels to end users. The information flows also include other data on such areas as economic activity, domestic production, and international petroleum supply.

The Integrating Module controls the execution of each of the component modules. To facilitate modularity, the components do not pass information to each other directly but communicate through a central data structure. This modular design provides the capability to execute modules individually, thus allowing decentralized development of the system and independent analysis and testing of individual modules. The modular design also permits the use of the methodology and level of detail most appropriate for each energy sector. NEMS calls each supply, conversion, and end-use demand module in sequence until the delivered prices of energy and the quantities demanded have converged within tolerance, thus achieving an economic equilibrium of supply and demand in the consuming sectors. A solution is reached annually through the projection horizon. Other variables, such as petroleum product imports, crude oil imports, and several macroeconomic indicators, also are evaluated for convergence.

Each NEMS component represents the impacts and costs of legislation and environmental regulations that affect that sector. NEMS accounts for all combustion-related carbon dioxide (CO_2) emissions, as well as emissions of sulfur dioxide (SO_2), nitrogen oxides (NO_x), and mercury from the electricity generation sector.

The version of NEMS used for *AEO2009* represents current legislation and environmental regulations as of November 2008 (such as the Energy Independence and Security Act of 2007 [EISA2007], which was signed into law on December 19, 2007; the Energy Policy Act of 2005 [EPACT2005]; the Working Families Tax Relief Act of 2004; and the American Jobs Creation Act of 2004), and the costs of compliance with regulations (such as the new stationary diesel regulations issued by the U.S. Environmental Protection Agency [EPA] in July 2006). It does not include representation of the American Recovery and Reinvestment Act, which was enacted in February 2009. The *AEO2009* models do not represent the Clean Air Mercury Rule (CAMR), which was vacated and remanded by the D.C. Circuit Court of the U.S. Court of Appeals on February 8, 2008, but they do represent State requirements for reduction of mercury emissions.

The *AEO2009* reference case also reflects the recent decision by the D.C. Circuit Court on July 11, 2008, to vacate and remand the NO_x and SO_2 cap-and-trade programs included in the Clean Air Interstate Rule (CAIR), but not the temporary reinstatement in a more recent ruling (issued on December 23, 2008, well after the cutoff date for inclusion in *AEO2009*). It is assumed, however, that electricity generators will continue to retrofit existing capacity with emissions control equipment to comply with the revised National Ambient Air Quality Standards (NAAQS), even without the CAIR regulations. Also, it is assumed that plants not equipped with scrubbers ultimately will be required to use low-sulfur coal in order to comply with the NAAQS. The potential impacts of pending or proposed Federal and State legislation, regulations, or standards—or of sections of legislation that have been enacted but require funds or implementing regulations that have not been provided or specified—are not reflected in NEMS.

In general, the historical data used for the *AEO2009* projections are based on EIA's *Annual Energy Review 2007*, published in June 2008 [*3*]; however, data were taken from multiple sources. In some cases, only partial or preliminary data were available for 2007. CO_2 emissions were calculated by using CO_2 coefficients from the EIA report, *Emissions of Greenhouse Gases in the United States 2007*, published in December 2008 [*4*]. Historical numbers are presented for comparison only and may be estimates. Source documents should be consulted for the official data values. Footnotes to the *AEO2009* appendix tables indicate the definitions and sources of historical data.

The *AEO2009* projections for 2008 and 2009 incorporate short-term projections from EIA's November 2008 *Short-Term Energy Outlook* (*STEO*). For short-term energy projections, readers are referred to monthly updates of the *STEO* [*5*].

Component Modules

The component modules of NEMS represent the individual supply, demand, and conversion sectors of domestic energy markets and also include international and macroeconomic modules. In general, the modules interact through values representing the prices or expenditures for energy delivered to the consuming sectors and the quantities of end-use energy consumption.

Macroeconomic Activity Module

The Macroeconomic Activity Module (MAM) provides a set of macroeconomic drivers to the energy modules, and there is a macroeconomic feedback mechanism within NEMS. Key macroeconomic variables used in the energy modules include gross domestic product (GDP), disposable income, value of industrial shipments, new housing starts, sales of new light-duty vehicles (LDVs), interest rates, and employment. The MAM uses the following models from IHS Global Insight: Macroeconomic Model of the U.S. Economy, National Industry Model, and National Employment Model. In addition, EIA has constructed a Regional Economic and Industry Model to project regional economic drivers, and a Commercial Floorspace Model to project 13 floorspace types in 9 Census divisions. The accounting framework for industrial value of shipments uses the North American Industry Classification System (NAICS).

International Module

The International Module represents the response of world oil markets (supply and demand) to assumed world oil prices. The results/outputs of the module are international liquids consumption and production by region and a crude oil supply curve representing international crude oil similar in quality to the West Texas Intermediate crude that is available to U.S. markets through the Petroleum Market Module (PMM) of NEMS. The supply-curve calculations are based on historical market data and a world oil supply/demand balance, which is developed from reduced-form models of international liquids supply and demand, current investment trends in exploration and development, and long-term resource economics for 221 countries/territories. The oil production estimates include both conventional and unconventional supply recovery technologies.

Residential and Commercial Demand Modules

The Residential Demand Module projects energy consumption in the residential sector by housing type and end use, based on delivered energy prices, the menu of equipment available, the availability of renewable sources of energy, and housing starts. The Commercial Demand Module projects energy consumption in the commercial sector by building type and nonbuilding uses of energy and by category of end use, based on delivered prices of energy, availability of renewable sources of energy, and macroeconomic variables representing interest rates and floorspace construction.

Both modules estimate the equipment stock for the major end-use services, incorporating assessments of advanced technologies, including representations of renewable energy technologies; and the effects of both building shell and appliance standards, including the recently enacted provisions of the Energy Independence and Security Act of 2007 (EISA2007). The Commercial Demand Module incorporates combined heat and power (CHP) technology. The modules also include projections of distributed generation. Both modules incorporate changes to "normal" heating and cooling degree-days by Census division, based on a 10-year average and on State-level population projections. The Residential Demand Module projects an increase in the average square footage of both new construction and existing structures, based on trends in the size of new construction and the remodeling of existing homes.

Industrial Demand Module

The Industrial Demand Module projects the consumption of energy for heat and power and for feedstocks and raw materials in each of 21 industries, subject to the delivered prices of energy and macroeconomic variables representing employment and the value of shipments for each industry. As noted in the description of the MAM, the value of shipments is based on NAICS. The industries are classified into three groups—energy-intensive manufacturing, non-energy-intensive manufacturing, and nonmanufacturing. Of the eight energy-intensive industries, seven are modeled in the Industrial Demand Module, with components for boiler/steam/cogeneration, buildings, and process/assembly use of energy. Bulk chemicals are further disaggregated to organic, inorganic, resins, and agricultural chemicals. A generalized representation of cogeneration and a recycling component also are included. The use of energy for petroleum refining is modeled in the PMM, and the projected consumption is included in the industrial totals.

Transportation Demand Module

The Transportation Demand Module projects consumption of fuels in the transportation sector, including petroleum products, electricity, methanol, ethanol, compressed natural gas, and hydrogen, by transportation mode, vehicle vintage, and size class, subject to delivered prices of energy fuels and macroeconomic variables representing disposable personal income, GDP, population, interest rates, and industrial shipments. Fleet vehicles are represented separately to allow analysis of the Energy Policy Act of 1992 (EPACT1992) and other legislation and legislative proposals. The transportation demand module also includes a component to assess the penetration of alternative-fuel vehicles (AFVs). EPACT2005 and the Energy Improvement and Extension Act of 2008 (EIEA2008) are reflected in the assessment of the impacts of tax credits on the purchase of hybrid gas-electric, alternative-fuel, and fuel-cell vehicles. The corporate average fuel economy (CAFE) and biofuel representation in the module reflect standards proposed by the National Highway Traffic Safety Administration (NHTSA) and provisions in EISA2007.

The air transportation component of the Transportation Demand Module explicitly represents air travel in domestic and foreign markets and includes the industry practice of parking aircraft in both domestic and international markets to reduce operating costs, as well as the movement of aging aircraft from passenger to cargo markets [*6*]. For passenger travel and air freight shipments, the module represents regional fuel use in regional, narrow-body, and wide-body aircraft. An infrastructure constraint, which is also modeled, can potentially limit overall growth in passenger and freight air travel to levels commensurate with industry-projected infrastructure expansion and capacity growth.

Electricity Market Module

The Electricity Market Module represents generation, transmission, and pricing of electricity, subject to delivered prices for coal, petroleum products, natural gas, and biofuels; costs of generation by all generating plants, including capital costs and macroeconomic variables for costs of capital and domestic investment; environmental emissions laws and regulations; and electricity load shapes and demand. There are three primary submodules—capacity planning, fuel dispatching, and finance and pricing.

All specifically identified options promulgated by the EPA for compliance with the Clean Air Act Amendments of 1990 (CAAA90) are explicitly represented in the capacity expansion and dispatch decisions; those that have not been promulgated (e.g., fine particulate proposals) are not incorporated. All financial incentives for power generation expansion and dispatch specifically identified in EPACT2005 have been implemented. Several States, primarily in the Northeast, have recently enacted air emission regulations for CO_2 that affect the electricity generation sector, and those regulations are represented in *AEO2009*.

Although currently there is no Federal legislation in place that restricts greenhouse gas (GHG) emissions, regulators and the investment community are beginning to push energy companies to invest in technologies that are less GHG-intensive. The trend is captured in the *AEO2009* reference case through a 3-percentage-point increase in the cost of capital when investments in new coal-fired power plants without carbon control and sequestration (CCS) and new coal-to-liquids (CTL) plants are evaluated.

Renewable Fuels Module

The Renewable Fuels Module (RFM) includes submodules representing renewable resource supply and technology input information for central-station, grid-connected electricity generation technologies, including conventional hydroelectricity, biomass (Dedicated biomass plants and co-firing in existing coal plants), geothermal, landfill gas, solar thermal electricity, solar photovoltaics (PV), and wind energy. The RFM contains renewable resource supply estimates representing the regional opportunities for renewable energy development. Investment tax credits (ITCs) for renewable fuels are incorporated, as currently enacted, including a permanent 10-percent ITC for business investment in solar energy (thermal nonpower uses as well as power uses) and geothermal power (available only to those projects not accepting the production tax credit [PTC] for geothermal power). In addition, the module reflects the increase in the ITC to 30 percent for solar energy systems installed before January 1, 2017, and the extension of the credit to individual homeowners under EIEA2008.

PTCs for wind, geothermal, landfill gas, and some types of hydroelectric and biomass-fueled plants also are represented. They provide a credit of up to 2.0 cents per kilowatthour for electricity produced in the first 10 years of plant operation. For *AEO2009*, new plants coming on line before January 1, 2010, are eligible to receive the ITC. *AEO2009* also accounts for new renewable energy capacity resulting from State renewable portfolio standard (RPS) programs, mandates, and goals, as described in *Assumptions to the Annual Energy Outlook 2009* [7].

Oil and Gas Supply Module

The Oil and Gas Supply Module represents domestic crude oil and natural gas supply within an integrated framework that captures the interrelationships among the various sources of supply: onshore, offshore, and Alaska by both conventional and unconventional techniques, including natural gas recovery from coalbeds and low-permeability formations of sandstone and shale. The framework analyzes cash flow and profitability to compute investment and drilling for each of the supply sources, based on the prices for crude oil and natural gas, the domestic recoverable resource base, and the state of technology. Oil and natural gas production activities are modeled for 12 supply regions, including 3 offshore and 3 Alaskan regions.

Crude oil production quantities are used as inputs to the PMM in NEMS for conversion and blending into refined petroleum products. Supply curves for natural gas are used as inputs to the Natural Gas Transmission and Distribution Module for determining natural gas prices and quantities.

Natural Gas Transmission and Distribution Module

The Natural Gas Transmission and Distribution Module represents the transmission, distribution, and pricing of natural gas, subject to end-use demand for natural gas and the availability of domestic natural gas and natural gas traded on the international market. The module tracks the flows of natural gas and determines the associated capacity expansion requirements in an aggregate pipeline network, connecting the domestic and foreign supply regions with 12 U.S. demand regions. The flow of natural gas is determined for both a peak and off-peak period in the year. Key components of pipeline and distributor tariffs are included in separate pricing algorithms. The module also represents foreign sources of natural gas, including pipeline imports and exports to Canada and Mexico, and LNG imports and exports.

Petroleum Market Module

The PMM projects prices of petroleum products, crude oil and product import activity, and domestic refinery operations (including fuel consumption), subject to the demand for petroleum products, the availability and price of imported petroleum, and the domestic production of crude oil, natural gas liquids, and biofuels (ethanol, biodiesel, and biomass-to-liquids [BTL]). The module represents refining activities in the five PADDs, as well as a less detailed representation of refining activities in the rest of the world. It explicitly models the requirements of EISA2007 and CAAA90 and the costs of automotive fuels, such as conventional and reformulated gasoline, and includes the production of biofuels for blending in gasoline and diesel.

AEO2009 represents regulations that limit the sulfur content of all nonroad and locomotive/marine diesel to 15 parts per million (ppm) by mid-2012. The module also reflects the new renewable fuels standard (RFS) in EISA2007 that requires the use of 36 billion gallons per year of biofuels by 2022 if achievable, with corn ethanol limited to 15 billion gallons per year. Demand growth and regulatory changes necessitate capacity expansion for refinery processing units. U.S. end-use prices are based on the marginal costs of production, plus markups representing the costs of product marketing, importing, transportation, and distribution, as well as applicable State and Federal taxes [*8*]. Refinery capacity expansion at existing sites is permitted in each of the five refining regions modeled.

Fuel ethanol and biodiesel are included in the PMM, because they are commonly blended into petroleum products. The module allows ethanol blending into gasoline at 10 percent or less by volume (E10) and up to 85 percent by volume (E85). For *AEO2009*, the level of allowable non-E85 ethanol blending in California has been raised from 5.7 percent to 10 percent in recent regulatory changes [*9*] that have set a framework for E10 emissions standards.

Ethanol is produced primarily in the Midwest from corn or other starchy crops, and in the future it may be produced from cellulosic material, such as switchgrass and poplar. Biodiesel (diesel-like fuel made in a trans-esterification process) is produced from seed oil, imported palm oil, animal fats, or yellow grease (primarily, recycled cooking oil). Renewable or "green" diesel is also modeled as a blending component in petroleum diesel. Unlike the more common biodiesel, renewable diesel is made by hydrogenation of vegetable oils and is completely fungible with petroleum diesel. Imports and limited exports of these biofuels are modeled in the PMM.

Both domestic and imported ethanol count toward the RFS. Domestic ethanol production from two feedstocks, corn and cellulosic materials, is modeled. Corn-based ethanol plants are numerous (more than 150 are now in operation, with a total production capacity of more than 10 billion gallons annually) and are based on a well-known technology that converts sugar into ethanol. Ethanol from cellulosic sources is a new technology with no pilot plants in operation; however, DOE awarded grants (up to $385 million) in 2007 to construct capacity totaling 147 million gallons per year, which *AEO2009* assumes will begin operating in 2012. Imported ethanol may be produced from cane sugar or bagasse, the cellulosic byproduct of sugar milling. The sources of ethanol are modeled to compete on an economic basis and to meet the EISA2007 renewable fuels mandate.

Fuels produced by gasification and Fischer-Tropsch synthesis are also modeled in the PMM, based on their economics relative to competing feedstocks and products. The three processes modeled are coal-to-liquids (CTL), gas-to-liquids (GTL), and BTL. CTL facilities are likely to be built at locations close to coal supplies and water sources, where liquid products and surplus electricity could also be distributed to nearby demand regions. GTL facilities may be built in Alaska, but they would compete with the Alaska Natural Gas Transportation System for available natural gas resources. BTL facilities are likely to be built where there are large supplies of biomass, such as crop residues and forestry waste. Because the BTL process uses cellulosic feedstocks, it is also modeled as a choice to meet the EISA2007 cellulosic biofuels requirement.

Coal Market Module

The Coal Market Module (CMM) simulates mining, transportation, and pricing of coal, subject to end-use demand for coal differentiated by heat and sulfur content. U.S. coal production is represented in the CMM by 40 separate supply curves—differentiated by region, mine type, coal rank, and sulfur content. The coal supply curves include a response to capacity utilization of mines, mining capacity, labor productivity, and factor input costs (mining equipment, mining labor, and fuel requirements). Projections of U.S. coal distribution are determined by minimizing the cost of coal supplied, given coal demands by demand region and sector, environmental restrictions, and accounting for minemouth prices, transportation costs, and coal supply contracts. Over the projection horizon, coal transportation costs in the CMM vary in response to changes in the cost of rail investments.

The CMM produces projections of U.S. steam and metallurgical coal exports and imports in the context of world coal trade, determining the pattern of world coal trade flows that minimizes the production and transportation costs of meeting a specified set of regional world coal import demands, subject to constraints on export capacities and trade flows. The international coal market component of the module computes trade in 3 types of coal for 17 export regions and 20 import regions. U.S. coal production and distribution are computed for 14 supply regions and 14 demand regions.

Annual Energy Outlook 2009 Cases

Table E1 provides a summary of the cases produced as part of the *AEO2009*. For each case, the table gives the name used in this report, a brief description of the major assumptions underlying the projections, the mode in which the case was run in NEMS (either fully integrated, partially integrated, or standalone), and a reference to the pages in the body of the report and in this appendix where the case is discussed. The text sections following Table E1 describe the various cases. The reference case assumptions for each sector are described in *Assumptions to the Annual Energy Outlook 2009* [*10*]. Regional results and other details of the projections are available at web site www.eia.doe.gov/oiaf/aeo/supplement.

Macroeconomic Growth Cases

In addition to the *AEO2009* reference case, the low economic growth and high economic growth cases were developed to reflect the uncertainty in projections of economic growth. The alternative cases are intended to show the effects of alternative growth assumptions on energy market projections. The cases are described as follows:

- The *low economic growth case* assumes lower growth rates for population (0.6 percent per year), nonfarm employment (0.5 percent per year), and labor productivity (1.5 percent per year), resulting in higher prices and interest rates and lower growth in industrial output. In the low economic growth case, economic output as measured by real GDP increases by 1.8 percent per year from 2007 through 2030, and growth in real disposable income per capita averages 1.5 percent per year.
- The *high economic growth case* assumes higher growth rates for population (1.3 percent per year), nonfarm employment (1.3 percent per year), and labor productivity (2.4 percent per year). With higher productivity gains and employment growth, inflation and interest rates are lower than in the reference case, and consequently economic output grows at a higher rate (3.0 percent per year) than in the reference case (2.5 percent). Disposable income per capita grows by 1.7 percent per year, compared with 1.6 percent in the reference case.

Oil Price Cases

The world oil price in *AEO2009* is defined as the average price of light, low-sulfur crude oil delivered in Cushing, Oklahoma, and is similar to the price for light, sweet crude oil traded on the New York Mercantile Exchange. *AEO2009* also includes a projection of the U.S. annual average refiners' acquisition cost of imported crude oil, which is more representative of the average cost of all crude oils used by refiners.

The historical record shows substantial variability in world oil prices, and there is arguably even more uncertainty about future prices in the long term. *AEO2009* considers three price cases (reference, low oil price, and high oil price) to allow an assessment of alternative views on the course of future oil prices. The low and high oil price cases define a wide range of potential price paths, reflecting different assumptions about decisions by OPEC members regarding the preferred rate of oil production and about the future finding and development costs and accessibility of conventional oil resources outside the United States. Because the low and high oil price cases are not fully integrated with a world economic model, the impact of world oil prices on international economies is not accounted for directly.

- In the *reference case*, real world oil prices rise from a low of $61 per barrel (2007 dollars) in 2009 to $110 per barrel in 2015, then increase more slowly to $130 per barrel in 2030. The reference case represents EIA's current judgment regarding exploration and development costs and accessibility of oil resources outside the United States. It also assumes that OPEC producers will choose to maintain their share of the market and will schedule investments in incremental production capacity so that OPEC's conventional oil production will represent about 40 percent of the world's total liquids production.
- In the *low oil price case*, real world oil prices are only $50 per barrel (2007 dollars) in 2030, compared with $130 per barrel in the reference case. The low oil price case assumes that OPEC countries will increase their conventional oil production to obtain approximately a 44-percent share of total world liquids production, and that oil resources outside the U.S. will be more accessible and/or less costly to produce (as a result of technology advances, more attractive fiscal regimes, or both) than in the reference case. With these assumptions, conventional oil production outside

Table E1. Summary of the *AEO2009* cases

Case name	Description	Integration mode	Reference in text	Reference in Appendix E
Reference	Baseline economic growth (2.5 percent per year from 2007 through 2030), world oil price, and technology assumptions. Complete projection tables in Appendix A.	Fully integrated	-	-
Low Economic Growth	Real GDP grows at an average annual rate of 1.8 percent from 2007 to 2030. Other energy market assumptions are the same as in the reference case. Partial projection tables in Appendix B.	Fully integrated	p. 58	p. 202
High Economic Growth	Real GDP grows at an average annual rate of 3.0 percent from 2007 to 2030. Other energy market assumptions are the same as in the reference case. Partial projection tables in Appendix B.	Fully integrated	p. 58	p. 202
Low Oil Price	More optimistic assumptions for economic access to non-OPEC resources and OPEC behavior than in the reference case. World light, sweet crude oil prices are $50 per barrel in 2030, compared with $130 per barrel in the reference case (2007 dollars). Other assumptions are the same as in the reference case. Partial projection tables in Appendix C.	Fully integrated	p. 60	p. 202
High Oil Price	More pessimistic assumptions for economic access to non-OPEC resources and OPEC behavior than in the reference case. World light, sweet crude oil prices are about $200 per barrel (2007 dollars) in 2030. Other assumptions are the same as in the reference case. Partial projection tables in Appendix C.	Fully integrated	p. 60	p. 202
Residential: 2009 Technology	Future equipment purchases based on equipment available in 2009. Existing building shell efficiencies fixed at 2009 levels. Partial projection tables in Appendix D.	With commercial	p. 63	p. 206
Residential: High Technology	Earlier availability, lower costs, and higher efficiencies assumed for more advanced equipment. Building shell efficiencies for new construction meet ENERGY STAR requirements after 2016. Partial projection tables in Appendix D.	With commercial	p. 63	p. 206
Residential: Best Available Technology	Future equipment purchases and new building shells based on most efficient technologies available by fuel. Building shell efficiencies for new construction meet the criteria for most efficient components after 2009. Partial projection tables in Appendix D.	With commercial	p. 64	p. 206
Commercial: 2009 Technology	Future equipment purchases based on equipment available in 2009. Building shell efficiencies fixed at 2009 levels. Partial projection tables in Appendix D.	With residential	p. 65	p. 206
Commercial: High Technology	Earlier availability, lower costs, and higher efficiencies for more advanced equipment. Building shell efficiencies for new and existing buildings increase by 8.8 and 6.3 percent, respectively, from 2003 values by 2030. Partial projection tables in Appendix D.	With residential	p. 65	p. 206
Commercial: Best Available Technology	Future equipment purchases based on most efficient technologies available by fuel. Building shell efficiencies for new and existing buildings increase by 10.5 and 7.5 percent, respectively, from 2003 values by 2030. Partial projection tables in Appendix D.	With residential	p. 66	p. 206

Table E1. Summary of the *AEO2008* cases (continued)

Case name	Description	Integration mode	Reference in text	Reference in Appendix E
Industrial: 2009 Technology	Efficiency of plant and equipment fixed at 2009 levels. Partial projection tables in Appendix D.	Standalone	p. 178	p. 207
Industrial: High Technology	Earlier availability, lower costs, and higher efficiencies for more advanced equipment. Partial projection tables in Appendix D.	Standalone	p. 178	p. 207
Transportation: Low Technology	Advanced technologies are more costly and less efficient than in the reference case. Partial projection tables in Appendix D.	Standalone	p. 69	p. 207
Transportation: High Technology	Advanced technologies are less costly and more efficient than in the reference case. Partial projection tables in Appendix D.	Standalone	p. 69	p. 207
Electricity: Low Nuclear Cost	New nuclear capacity has 25 percent lower capital and operating costs in 2030 than in the reference case. Partial projection tables in Appendix D.	Fully integrated	p. 181	p. 207
Electricity: High Nuclear Cost	Costs for new nuclear technology do not improve from 2009 levels in the reference case. Existing nuclear plants are retired after 55 years of service. Partial projection tables in Appendix D.	Fully integrated	p. 181	p. 208
Electricity: Low Fossil Technology Cost	Capital and operating costs for all new fossil-fired generating technologies improve by 25 percent in 2030 from reference case values. Partial projection tables in Appendix D.	Fully integrated	p. 182	p. 208
Electricity: High Fossil Technology Cost	Costs for new advanced fossil-fired generating technologies do not improve over time from 2009. Partial projection tables in Appendix D.	Fully integrated	p. 182	p. 208
Electricity: Frozen Plant Capital Costs	Base overnight costs for all new electric generating technologies are frozen at 2013 levels. Cost decreases due to learning still occur, but no declines in costs due to commodity price changes are assumed.	Fully integrated	p. 45	p. 208
Electricity: High Plant Capital Costs	Base overnight costs for all new electric generating technologies continue increasing throughout the projection, through a cost factor in 2030 that is 25 percentage points above the 2013 factor. Cost decreases due to learning can still occur and may partially offset the increases.	Fully integrated	p. 45	p. 208
Electricity: Falling Plant Capital Costs	Base overnight costs for all new electric generating technologies fall more rapidly than in the reference case, by assuming a cost factor 25 percentage points below the reference case cost factor in 2030.	Fully integrated	p. 45	p. 208
Renewable Fuels: High Renewable Technology Cost	New renewable generating technologies do not improve over time from 2009. Partial projection tables in Appendix D.	Fully integrated	p. 75	p. 208
Renewable Fuels: Low Renewable Technology Cost	Levelized cost of energy for nonhydropower renewable generating technologies declines by 25 percent in 2030 from reference case values. Partial projection tables in Appendix D.	Fully integrated	p. 75	p. 209
Renewable Fuels: Production Tax Credit Extension	Production Tax Credit for certain renewable generation is extended to projects constructed through 2019.	Fully integrated	p. 47	p. 209

Table E1. Summary of the *AEO2008* cases (continued)

Case name	Description	Integration mode	Reference in text	Reference in Appendix E
Oil and Gas: Rapid Technology	Cost, finding rate, and success rate parameters are adjusted for 50 percent more rapid improvement than in the reference case. Partial projection tables in Appendix D.	Fully integrated	p. 76	p. 209
Oil and Gas: Slow Technology	Cost, finding rate, and success rate parameters are adjusted for 50 percent slower improvement than in the reference case. Partial projection tables in Appendix D.	Fully Integrated	p. 76	p. 209
Oil and Gas: High LNG Supply	LNG imports are set exogenously to a factor times the reference case levels from 2010 forward, with the remaining assumptions unchanged from the reference case. The factor starts at 1.0 in 2010 and increases linearly to 5.0 in 2030. Partial projection tables in Appendix D.	Fully integrated	p. 192	p. 209
Oil and Gas: Low LNG Supply	LNG imports held constant at 2009 levels, with the remaining assumptions unchanged from the reference case. Partial projection tables in Appendix D.	Fully integrated	p. 192	p. 209
Oil and Gas: ANWR	The Arctic National Wildlife Refuge (ANWR) in Alaska is opened to Federal oil and natural gas leasing, with the remaining assumptions unchanged from the reference case. Partial projection tables in Appendix D.	Fully integrated	p. 193	p. 209
Oil and Gas: No Alaska Pipeline	A natural gas pipeline from the North Slope of Alaska to the lower 48 States is not built during the projection period.	Fully integrated	p. 78	p. 210
Oil and Gas: OCS Limited	Access to the Atlantic , Pacific , and Gulf of Mexico Outer Continental Shelf (OCS) is limited by reinstatement of leasing moratoria that lapsed in 2008.	Fully integrated	p. 35	p.210
Coal: Low Coal Cost	Productivity growth rates for coal mining are higher than in the reference case, and coal mining wages, mine equipment, and coal transportation rates are lower. Partial projection tables in Appendix D.	Fully integrated	p. 83	p. 210
Coal: High Coal Cost	Productivity growth rates for coal mining are lower than in the reference case, and coal mining wages, mine equipment, and coal transportation rates are higher. Partial projection tables in Appendix D.	Fully integrated	p. 83	p. 210
Integrated 2009 Technology	Combination of the residential, commercial, and industrial 2009 technology cases and the electricity high fossil technology cost, high renewable technology cost, and high nuclear cost cases. Partial projection tables in Appendix D.	Fully integrated	p. 176	p. 210
Integrated High Technology	Combination of the residential, commercial, industrial, and transportation high technology cases and the electricity low fossil technology cost, low renewable technology cost, and low nuclear cost cases. Partial projection tables in Appendix D.	Fully integrated	p. 176	p. 210
No GHG Concern	No greenhouse gas emissions reduction policy is enacted, and market investment decisions are not altered in anticipation of such a policy.	Fully integrated	p. 50	p. 211
LW110	Based on the greenhouse gas emissions reduction policy proposed by Senators Lieberman and Warner in the 110th Congress (S. 2191).	Fully integrated	p. 50	p. 211
No 2008 Tax Legislation	EIEA2008 tax legislation is removed from the reference case.	Fully integrated	p. 66	p. 211

the U.S. is higher in the low oil price case than in the reference case.

- In the *high oil price case*, real world oil prices reach about $200 per barrel (2007 dollars) in 2030. The high oil price case assumes that OPEC countries will reduce their production from the current rate, sacrificing market share as global liquids production increases, and that oil resources outside the United States will be less accessible and/or more costly to produce than assumed in the reference case.

Buildings Sector Cases

In addition to the *AEO2009* reference case, three standalone technology-focused cases using the Residential and Commercial Demand Modules of NEMS were developed to examine the effects of changes in equipment and building shell efficiencies.

For the residential sector, the three technology-focused cases are as follows:

- The *2009 technology case* assumes that all future equipment purchases are based only on the range of equipment available in 2009. Existing building shell efficiencies are assumed to be fixed at 2009 levels (no further improvements). For new construction, building shell technology options are constrained to those available in 2009.
- The *high technology case* assumes earlier availability, lower costs, and higher efficiencies for more advanced equipment [*11*]. For new construction, building shell efficiencies are assumed to meet ENERGY STAR requirements after 2016.
- The *best available technology case* assumes that all future equipment purchases are made from a menu of technologies that includes only the most efficient models available in a particular year for each fuel, regardless of cost. For new construction, building shell efficiencies are assumed to meet the criteria for the most efficient components after 2009.

For the commercial sector, the three technology-focused cases are as follows:

- The *2009 technology case* assumes that all future equipment purchases are based only on the range of equipment available in 2009. Building shell efficiencies are assumed to be fixed at 2009 levels.
- The *high technology case* assumes earlier availability, lower costs, and/or higher efficiencies for more advanced equipment than in the reference case [*12*]. Building shell efficiencies for new and existing buildings in 2030 are assumed to be 8.8 percent and 6.3 percent higher, respectively, than their 2003 levels—a 25-percent improvement relative to the reference case.
- The *best available technology case* assumes that all future equipment purchases are made from a menu of technologies that includes only the most efficient models available in a particular year for each fuel, regardless of cost. Building shell efficiencies for new and existing buildings in 2030 are assumed to be 10.5 percent and 7.5 percent higher, respectively, than their 2003 values—a 50-percent improvement relative to the reference case.

The Residential and Commercial Demand Modules of NEMS were also used to complete the high and low renewable technology cost cases, which are discussed in more detail below in the Renewable Fuels Cases section. In combination with assumptions for electricity generation from renewable fuels in the electric power sector and industrial sector, these sensitivity cases analyze the impacts of changes in generating technologies that use renewable fuels and in the availability of renewable energy sources. For the Residential and Commercial Demand Modules:

- The *low renewable technology cost case* assumes greater improvements in residential and commercial PV and wind systems than in the reference case. The assumptions result in capital cost estimates for 2030 that are approximately 25 percent lower than reference case costs for distributed PV technologies.
- The *high renewable technology cost case* assumes that costs and performance levels for residential and commercial PV and wind systems remain constant at 2009 levels through 2030.

Industrial Sector Cases

In addition to the *AEO2009* reference case, two standalone cases using the Industrial Demand Module of NEMS were developed to examine the effects of less rapid and more rapid technology change and adoption. Because they are standalone cases, the energy intensity changes discussed in this section exclude the refining industry. Energy use in the refining industry is estimated as part of the Petroleum Market Module in NEMS. The Industrial Demand Module also was used as part of the integrated low and high renewable technology cost cases. For the industrial sector:

- The *2009 technology case* holds the energy efficiency of plant and equipment constant at the 2009 level over the projection period. In this case, delivered energy intensity falls by 1.1 percent annually from 2007 to 2030, as compared with 1.5 percent annually in the reference case. Changes in aggregate energy intensity may result both from changing equipment and production efficiency and from changing composition of industrial output. Because the level and composition of industrial output are the same in the reference, 2009 technology, and high technology cases, any change in energy intensity in the two technology cases is attributable to efficiency changes.
- The *high technology case* assumes earlier availability, lower costs, and higher efficiency for more advanced equipment [*13*] and a more rapid rate of improvement in the recovery of biomass byproducts from industrial processes (0.7 percent per year, as compared with 0.4 percent per year in the reference case). The same assumption is incorporated in the integrated low renewable technology cost case, which focuses on electricity generation. Although the choice of the 0.7-percent annual rate of improvement in byproduct recovery is an assumption in the high technology case, it is based on the expectation that there would be higher recovery rates and substantially increased use of CHP in that case. Delivered energy intensity falls by 1.7 percent annually in the high technology case.

The 2009 technology case was run with only the Industrial Demand Module, rather than in fully integrated NEMS runs. Consequently, no potential feedback effects from energy market interactions are captured, and energy consumption and production in the refining industry, which are modeled in the PMM, are excluded.

Transportation Sector Cases

In addition to the *AEO2009* reference case, two standalone cases using the NEMS Transportation Demand Module were developed to examine the effects of advanced technology costs and efficiency improvement on technology adoption and vehicle fuel economy [*14*]. For the transportation sector:

- In the *low technology case,* the characteristics of conventional technologies, advanced technologies, and alternative-fuel LDVs, heavy-duty vehicles, and aircraft reflect more pessimistic assumptions about cost and efficiency improvements achieved over the projection. More pessimistic assumptions for fuel efficiency improvement are also reflected in the rail and shipping sectors.
- In the *high technology case*, the characteristics of conventional and alternative-fuel light-duty vehicles reflect more optimistic assumptions about incremental improvements in fuel economy and costs. In the freight truck sector, the high technology case assumes more rapid incremental improvement in fuel efficiency for engine and emissions control technologies. More optimistic assumptions for fuel efficiency improvements are also made for the air, rail, and shipping sectors.

The low technology and high technology cases were run with only the Transportation Demand Module rather than as fully integrated NEMS runs. Consequently, no potential macroeconomic feedback related to vehicles costs or travel demand was captured, nor were changes in fuel prices incorporated.

Electricity Sector Cases

In addition to the reference case, several integrated cases with alternative electric power assumptions were developed to analyze uncertainties about the future costs and performance of new generating technologies. Two of the cases examine alternative assumptions for nuclear power technologies, and two examine alternative assumptions for fossil fuel technologies. Three additional cases examine alternative cost paths for all technologies, based on uncertainties in the underlying commodity prices that influence power plant construction costs. Reference case values for technology characteristics are determined in consultation with industry and government specialists; however, there is always uncertainty surrounding the major component costs. The electricity cases analyze what could happen if costs of new plants were either higher or lower than assumed in the reference case. The cases are fully integrated to allow feedback between the potential shifts in fuel consumption and fuel prices.

Nuclear Technology Cost Cases

- The cost assumptions for the *low nuclear cost case* reflect a 25-percent reduction in the capital and operating costs for advanced nuclear technology in 2030, relative to the reference case. The reference case projects a 29-percent reduction in the capital costs of nuclear power plants from 2009 to 2030; the low nuclear cost case assumes a 46-percent reduction from 2009 to 2030.

- The *high nuclear cost case* assumes that capital costs for the advanced nuclear technology do not decline during the projection period but remain fixed at the 2009 levels assumed in the reference case. This case also assumes that existing nuclear plants are retired after 55 years of operation, as compared with a maximum 60-year life in the reference case. There is considerable uncertainty surrounding the technical lifetime for some of the major components of older nuclear plants.

Fossil Cost Technology Cases

- In the *low fossil technology cost case*, capital costs and operating costs for all coal- and natural-gas-fired generating technologies are assumed to be 25 percent lower than reference case levels in 2030. Because learning in the reference case reduces costs with manufacturing experience, costs in the low fossil cost case are reduced by 40 to 47 percent between 2009 and 2030, depending on the technology.
- In the *high fossil technology cost case*, capital costs for all coal- and natural-gas-fired generating technologies do not decline during the projection period but remain fixed at the 2009 values assumed in the reference case.

Additional details about annual capital costs, operating and maintenance costs, plant efficiencies, and other factors used in the high and low fossil technology cost cases will be provided in *Assumptions to the Annual Energy Outlook 2009* [*15*].

Electricity Plant Capital Cost Cases

The costs to build new power plants have risen dramatically in the past few years, primarily as a result of significant increases in the costs of construction-related materials, such as cement, iron, steel, and copper. For the *AEO2009* reference case, initial overnight costs for all technologies were updated to be consistent with costs estimates in the early part of 2008. A cost adjustment factor based on the projected producer price index for metals and metal products was also implemented, allowing the overnight costs to fall in the future if the index drops, or to rise further if the index increases. Although there is significant correlation between commodity prices and power plant construction costs, other factors may influence future costs, raising the uncertainties surrounding the future costs of building new power plants. For *AEO2009*, three additional cost cases focus on the uncertainties of future plant construction costs. The three cases use exogenous assumptions for the annual adjustment factors, rather than linking to the metals price index. The cases are discussed in "Electricity Plant Cost Uncertainties" in the Issues in Focus section of this report.

- In the *frozen plant capital costs case,* base overnight costs for all new generating technologies are assumed to be frozen at 2013 levels. Cost decreases still can occur with learning. In this case, costs do decline slightly over the projection, but capital costs are roughly 20 percent above reference case costs in 2030.
- In the *high plant capital costs case*, base overnight costs for all new generating technologies are assumed to continue increasing throughout the projection, with the cost factor increasing by 25 percentage points from 2013 to 2030. Cost decreases still can occur with learning, and they may partially offset the increases, but costs for most technologies in 2030 are above current costs and about 50 percent higher than projected costs in 2030 in the reference case.
- In the *falling plant capital costs case*, base overnight costs for all new generating technologies are assumed to fall more rapidly than in the reference case, starting in 2013. In 2030, the cost factor is assumed to be 25 percentage points below the reference case value.

Renewable Fuels Cases

In addition to the *AEO2009* reference case, two integrated cases with alternative assumptions about renewable fuels were developed to examine the effects of less aggressive and more aggressive improvement in the cost of renewable technologies. The cases are as follows:

- In the *high renewable technology cost case*, capital costs, operating and maintenance costs, and performance levels for wind, solar, biomass, and geothermal resources are assumed to remain constant at 2009 levels through 2030. Although biomass prices are not changed from the reference case, this case assumes that dedicated energy crops (also known as "closed-loop" biomass fuel supply) do not become available.

- In the *low renewable technology cost case*, the levelized costs of energy resources for generating technologies using renewable resources are assumed to decline to 25 percent below the reference case costs for the same resources in 2030. In general, lower costs are represented by reducing the capital costs of new plant construction. Biomass fuel supplies also are assumed to be 25 percent less expensive than in the reference case for the same resource quantities used in the reference case. Assumptions for other generating technologies are unchanged from those in the reference case. In the low renewable technology cost case, the rate of improvement in recovery of biomass byproducts from industrial processes is also increased.
- In the *production tax credit extension case,* an additional extension of the PTC is provided to all eligible resources modeled in *AEO2009*. In this case, plants entering service by December 31, 2019, are assumed to be eligible for the PTC. Under current law as of December 2008, the PTC for certain renewable generation technologies, including geothermal, biomass, hydroelectric, and landfill gas, will not be available for plants constructed after December 31, 2010. For wind, the PTC will not be available to plants constructed after December 31, 2009. This law has been renewed periodically, however, either before or within a several months after its expiration.

Oil and Gas Supply Cases

The sensitivity of the projections to changes in the assumed rates of technological progress in oil and natural gas supply and LNG imports are examined in four cases:

- In the *rapid technology case*, the parameters representing the effects of technological progress on finding rates, drilling costs, lease equipment and operating costs, and success rates for conventional oil and natural gas drilling in the reference case are improved by 50 percent. Improvements in a number of key exploration and production technologies for unconventional natural gas also are increased by 50 percent in the rapid technology case. Key supply parameters for Canadian oil and natural gas also are modified to simulate the assumed impacts of more rapid oil and natural gas technology penetration on Canadian supply potential. All other parameters in the model are kept at the reference case values, including technology parameters for other modules, parameters affecting foreign oil supply, and assumptions about imports and exports of LNG and natural gas trade between the United States and Mexico. Specific detail by region and fuel category is provided in *Assumptions to the Annual Energy Outlook 2009* [*16*].
- In the *slow technology case*, the parameters representing the effects of technological progress on finding rates, drilling, lease equipment and operating costs, and success rates for conventional oil and natural gas drilling are 50 percent less optimistic than those in the reference case. Improvements in a number of key exploration and production technologies for unconventional natural gas also are reduced by 50 percent in the slow technology case. Key Canadian supply parameters also are modified to simulate the assumed impacts of slow oil and natural gas technology penetration on Canadian supply potential. All other parameters in the model are kept at the reference case values.
- The *high LNG supply case* exogenously specifies LNG import levels for 2010 through 2030 equal to a factor times the reference case levels. The factor starts at 1 in 2010 and increases linearly to 5 in 2030. The intent is to project the potential impact on domestic natural gas markets if LNG imports turn out to be higher than projected in the reference case.
- The *low LNG supply case* exogenously specifies LNG imports at the 2009 levels projected in the reference case for the period 2010 through 2030. The intent is to project the potential impact on domestic natural gas markets if LNG imports turn out to be lower than projected in the reference case.

Additional cases show the potential impacts of lifting leasing restrictions in the Arctic National Wildlife Refuge (ANWR), of conditions that result in no construction of an Alaska pipeline before 2030, and of reinstating the Outer Continental Shelf (OCS) leasing moratoria that expired on September 30, 2008.

- The *ANWR case* assumes that Federal legislation passed during 2009 permits Federal oil and gas leasing in ANWR's 1002 area, and that oil and natural gas leasing will commence after 2009 in the State and Native lands that are either in or adjoining ANWR.

- The *no Alaska pipeline case* examines the natural gas market impacts of assuming that a pipeline to move North Slope gas from Alaska to the lower 48 States is not constructed during the projection period. Currently, there are no specific prohibitions on the construction of such a pipeline; however, political, business, and/or economic factors could lead to indefinite postponement of the project.
- The *OCS limited case* assumes that the OCS leasing allowed by Congress to expire on September 30, 2008, does not expire and will continue to be renewed annually throughout the projection period, thus prohibiting offshore drilling for oil and natural gas in the Pacific, the Atlantic, most of the Eastern Gulf of Mexico, and a small area in the Central Gulf of Mexico OCS. In the OCS limited case, technically recoverable resources in the OCS total 75 billion barrels of oil and 380 trillion cubic feet of natural gas, as compared with 93 billion barrels and 456 trillion cubic feet in the reference case.

Coal Market Cases

Two alternative coal cost cases examine the impacts on U.S. coal supply, demand, distribution, and prices that result from alternative assumptions about mining productivity, labor costs, mine equipment costs, and coal transportation rates. The alternative productivity and cost assumptions are applied in every year from 2010 through 2030. For the coal cost cases, adjustments to the reference case assumptions for coal mining productivity are based on variation in the average annual productivity growth of 3.6 percent observed since 1980. Transportation rates are lowered (in the low cost case) or raised (in the high cost case) from reference case levels to achieve a 25-percent change in rates relative to the reference case in 2030. The low and high coal cost cases represent fully integrated NEMS runs, with feedback from the macroeconomic activity, international, supply, conversion, and end-use demand modules.

- In the *low coal cost case*, the average annual growth rates for coal mining productivity are higher than those in the reference case and are applied at the supply curve level. As an example, the average annual growth rate for Wyoming's Southern Powder River Basin supply curve is increased from -0.5 percent in the reference case for the years 2010 through 2030 to 3.1 percent in the low coal cost case. Coal mining wages, mine equipment costs, and other mine supply costs all are assumed to be about 20 percent lower in 2030 in real terms in the low coal cost case than in the reference case. Coal transportation rates, excluding the impact of fuel surcharges, are assumed to be 25 percent lower in 2030.
- In the *high coal cost case*, the average annual productivity growth rates for coal mining are lower than those in the reference case and are applied as described in the *low coal cost case*. Coal mining wages, mine equipment costs, and other mine supply costs in 2030 are assumed to be about 20 percent higher than in the reference case, and coal transportation rates in 2030 are assumed to be 25 percent higher.

Additional details about the productivity, wage, mine equipment cost, and coal transportation rate assumptions for the reference and alternative coal cost cases are provided in Appendix D.

Cross-Cutting Integrated Cases

In addition to the sector-specific cases described above, a series of cross-cutting integrated cases are used in *AEO2009* to analyze specific scenarios with broader sectoral impacts. For example, two integrated technology progress cases combine the assumptions from the other technology progress cases to analyze the broader impacts of more rapid and slower technology improvement rates. In addition, two cases also were run with alternative assumptions about future regulation of GHG emissions.

Integrated Technology Cases

The *integrated 2009 technology case* combines the assumptions from the residential, commercial, and industrial 2009 technology cases and the electricity high fossil technology cost, high renewable technology cost, and high nuclear cost cases. The *integrated high technology case* combines the assumptions from the residential, commercial, industrial, and transportation high technology cases and the electricity high fossil technology cost, low renewable technology cost, and low nuclear cost cases.

Greenhouse Gas Uncertainty Cases

Although currently no legislation restricting GHG emissions is in place in the United States, regulators and the investment community are beginning to push energy companies to invest in less GHG-intensive technologies, as captured in the reference case by assuming a 3-percentage-point increase in the cost of capital for investments in new coal-fired power plants without CCS and new CTL plants. Those assumptions affect cost evaluations for the construction of new capacity but not the actual operating costs when a new plant begins operation.

Two alternative cases are used to provide a range of outcomes, from no concern about future GHG legislation to the imposition of a specific GHG limit. The *no GHG concern case*, which was run without any adjustment for concern about potential GHG regulations, is similar to the reference cases from previous *AEO*s (without the 3-percentage-point increase). In the no GHG concern case, the same cost of capital is used to evaluate all new capacity builds, regardless of type. The *LW110 case* assumes implementation of a GHG emissions reduction policy that affects both investment and operating costs. Assumptions for the LW110 case are based on S. 2191, the Lieberman-Warner Climate Security Act of 2007 in the 110th Congress, as modeled in an earlier EIA analysis [*17*]. Results from the LW110 case should be viewed as illustrative, because the impact of any policy to reduce GHG emissions will depend on its detailed specifications, which are likely to differ from those in the LW110 case.

No 2008 Tax Legislation Case

Because the *AEO2009* reference case includes the tax provisions from EIEA2008 [*18*], a *no 2008 tax legislation case* is used to examine the impacts of those specific tax provisions.

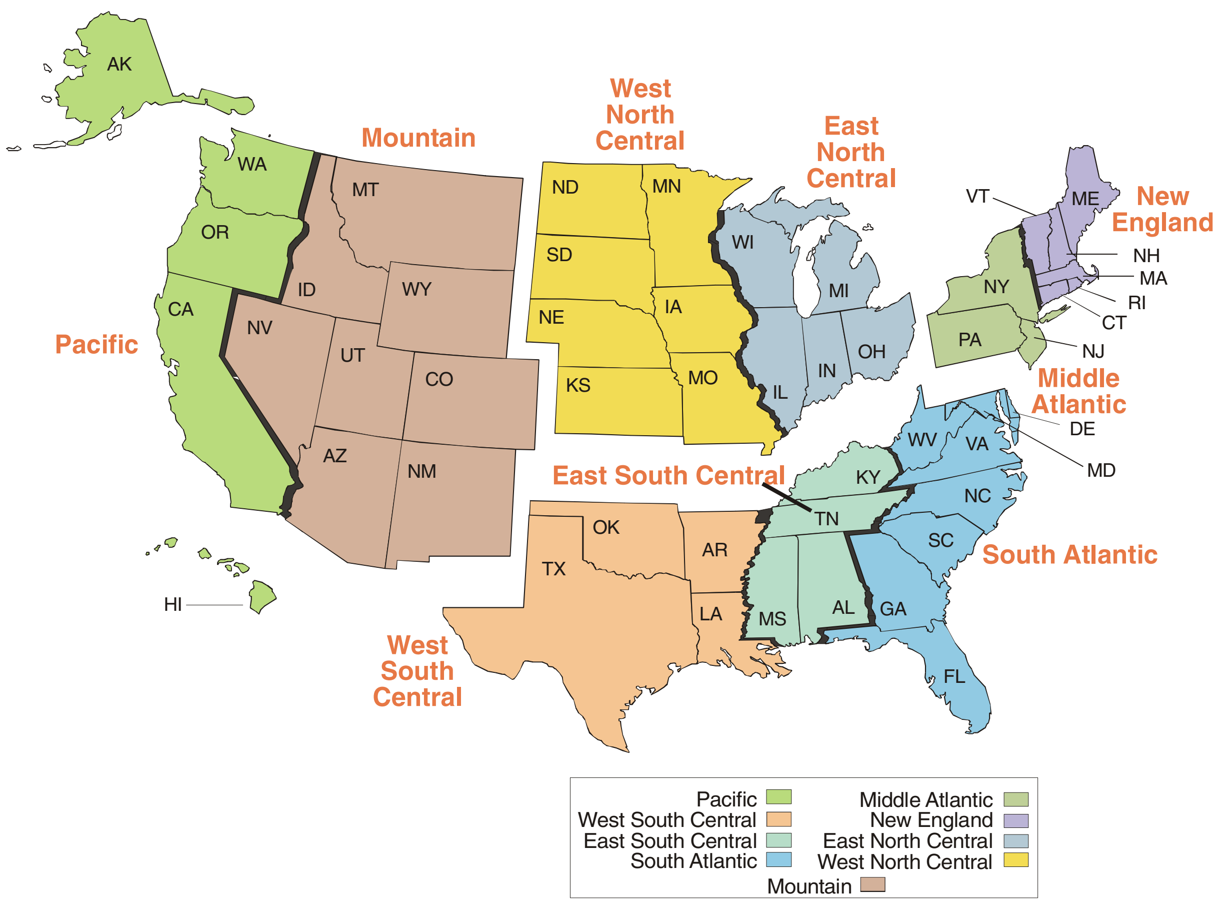
Endnotes

1. Energy Information Administration, *The National Energy Modeling System: An Overview 2003*, DOE/EIA-0581(2003) (Washington, DC, March 2003), web site www.eia.doe.gov/oiaf/aeo/overview.
2. For *AEO2010*, the projection period is expected to be extended to 2035.
3. Energy Information Administration, *Annual Energy Review 2007*, DOE/EIA-0384(2007) (Washington, DC, June 2008), web site www.eia.doe.gov/emeu/aer/contents.html.
4. Energy Information Administration, *Emissions of Greenhouse Gases in the United States 2007*, DOE/EIA-0573(2007) (Washington, DC, December, 2008), web site www.eia.doe.gov/oiaf/1605/ggrpt/index.html.
5. Energy Information Administration, *Short-Term Energy Outlook*, web site www.eia.doe.gov/emeu/steo/pub/contents.html. Portions of the preliminary information were also used to initialize the NEMS Petroleum Market Module projection.
6. Jet Information Services, Inc., *World Jet Inventory Year-End 2006* (Utica, NY, March 2007); and personal communication from Stuart Miller (Jet Information Services).
7. Energy Information Administration, *Assumptions to the Annual Energy Outlook 2009*, DOE/EIA-0554 (2009) (Washington, DC, March 2009), web site www.eia.doe.gov/oiaf/aeo/assumption.
8. For gasoline blended with ethanol, the tax credit of 51 cents (nominal) per gallon of ethanol is assumed to be available for 2008; however, it is reduced to 45 cents starting in 2009 (the year after annual U.S. ethanol consumption surpasses 7.5 billion gallons), as mandated by the Food, Conservation, and Energy Act of 2008 (the Farm Bill), and it is set to expire after 2010. In addition, modeling updates include the Farm Bill's mandated extension of the ethanol import tariff, at 54 cents per gallon, to December 31, 2010. Finally, again in accordance with the Farm Bill, a new cellulosic ethanol producer's tax credit of $1.01 per gallon, valid through 2012, is implemented in the model; however, it is reduced by the amount of the blender's tax credit amount. Thus, in 2009 and 2010, the cellulosic ethanol producer's tax credit is modeled as $1.01 - $0.45 = $0.56 per gallon, and in 2011 and 2012 it is set at $1.01 per gallon.
9. California Environmental Protection Agency, Air Resources Board, "Phase 3 California Reformulated Gasoline Regulations," web site www.arb.ca.gov/regact/2007/carfg07/carfg07.htm.
10. Energy Information Administration, *Assumptions to the Annual Energy Outlook 2009*, DOE/EIA-0554 (2009) (Washington, DC, March 2009), web site www.eia.doe.gov/oiaf/aeo/assumption.
11. High technology assumptions for the residential sector are based on Energy Information Administration, *EIA—Technology Forecast Updates—Residential and Commercial Building Technologies—Advanced Case Second Edition (Revised)* (Navigant Consulting, Inc., September 2007), and *EIA—Technology Forecast Updates—Residential and Commercial Building Technologies—Advanced Case: Residential and Commercial Lighting, Commercial Refrigeration, and Commercial Ventilation Technologies* (Navigant Consulting, Inc., September 2008).
12. High technology assumptions for the commercial sector are based on Energy Information Administration, *EIA—Technology Forecast Updates—Residential and Commercial Building Technologies—Advanced Case Second Edition (Revised)* (Navigant Consulting, Inc., September 2007), and *EIA—Technology Forecast Updates—Residential and Commercial Building Technologies—Advanced Case: Residential and Commercial Lighting, Commercial Refrigeration, and Commercial Ventilation Technologies* (Navigant Consulting, Inc., September 2008).

13. These assumptions are based in part on Energy Information Administration, *Industrial Technology and Data Analysis Supporting the NEMS Industrial Model* (FOCIS Associates, October 2005).
14. Energy Information Administration, *Documentation of Technologies Included in the NEMS Fuel Economy Model for Passenger Cars and Light Trucks* (Energy and Environmental Analysis, September 2003).
15. Energy Information Administration, *Assumptions to the Annual Energy Outlook 2009*, DOE/EIA-0554 (2009) (Washington, DC, March 2009), web site www.eia.doe.gov/oiaf/aeo/assumption.
16. Energy Information Administration, *Assumptions to the Annual Energy Outlook 2009*, DOE/EIA-0554 (2009) (Washington, DC, March 2009), web site www.eia.doe.gov/oiaf/aeo/assumption.
17. See Energy Information Administration, *Energy Market and Economic Impacts of S. 2191, the Lieberman-Warner Climate Security Act of 2007*, SR/OIAF/2008-01 (Washington, DC, April 2008), web site www.eia.doe.gov/oiaf/servicerpt/s2191/pdf/sroiaf(2008)01.pdf.
18. See pages 9-12 in the Legislation and Regulations section of this report.

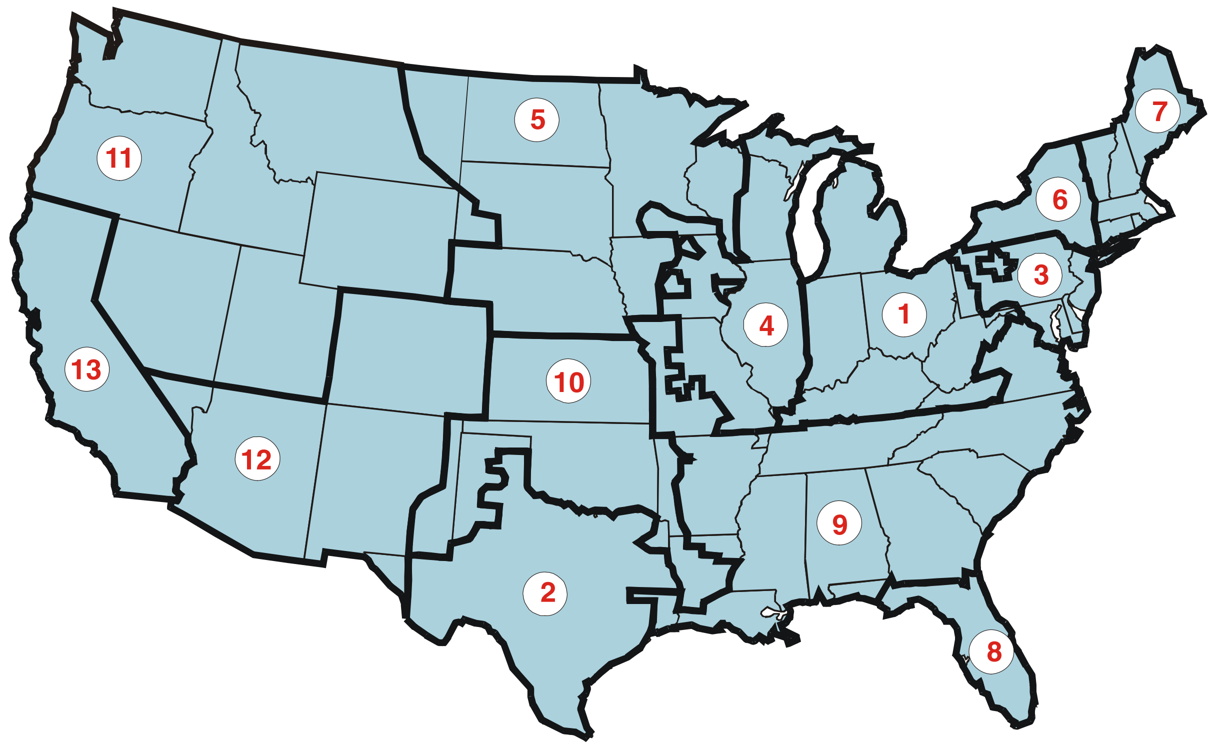
Regional Maps

F1. United States Census Divisions



Source: Energy Information Administration. Office of Integrated Analysis and Forecasting.

F2. Electricity Market Module Regions



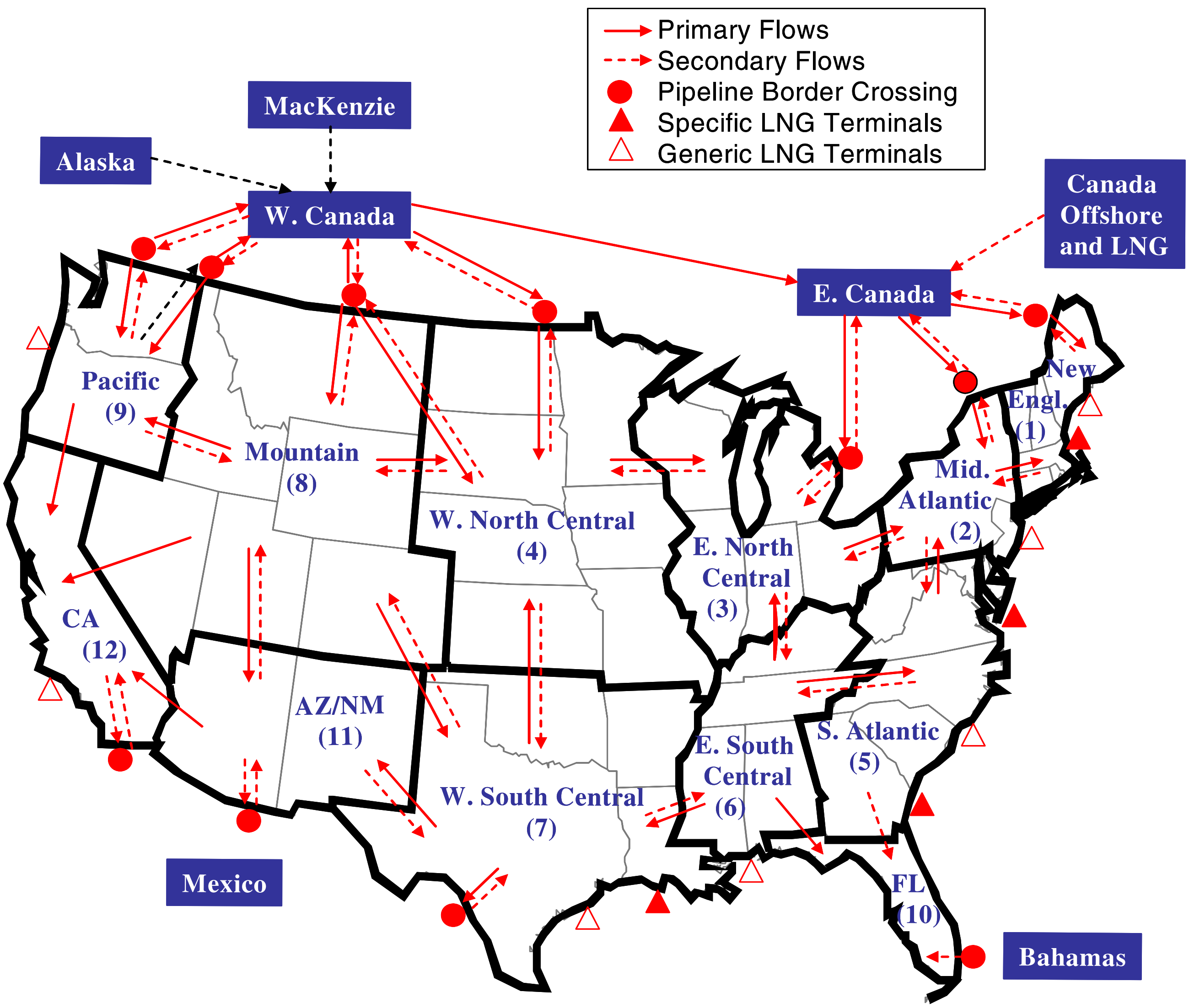
1 East Central Area Reliability Coordination Agreement (ECAR)
2 Electric Reliability Council of Texas (ERCOT)
3 Mid-Atlantic Area Council (MAAC)
4 Mid-America Interconnected Network (MAIN)
5 Mid-Continent Area Power Pool (MAPP)
6. New York (NY)
7. New England (NE)
8. Florida Reliability Coordinating Council (FL)
9. Southeastern Electric Reliability Council (SEF
10. Southwest Power Pool (SPP)
11. Northwest Power Pool (NWP)
12. Rocky Mountain Power Area, Arizona, New Mexico, and Southern Nevada (RA)
13. California (CA)

Source: Energy Information Administration. Office of Integrated Analysis and Forecasting.

F3. Oil and Gas Supply Model Regions

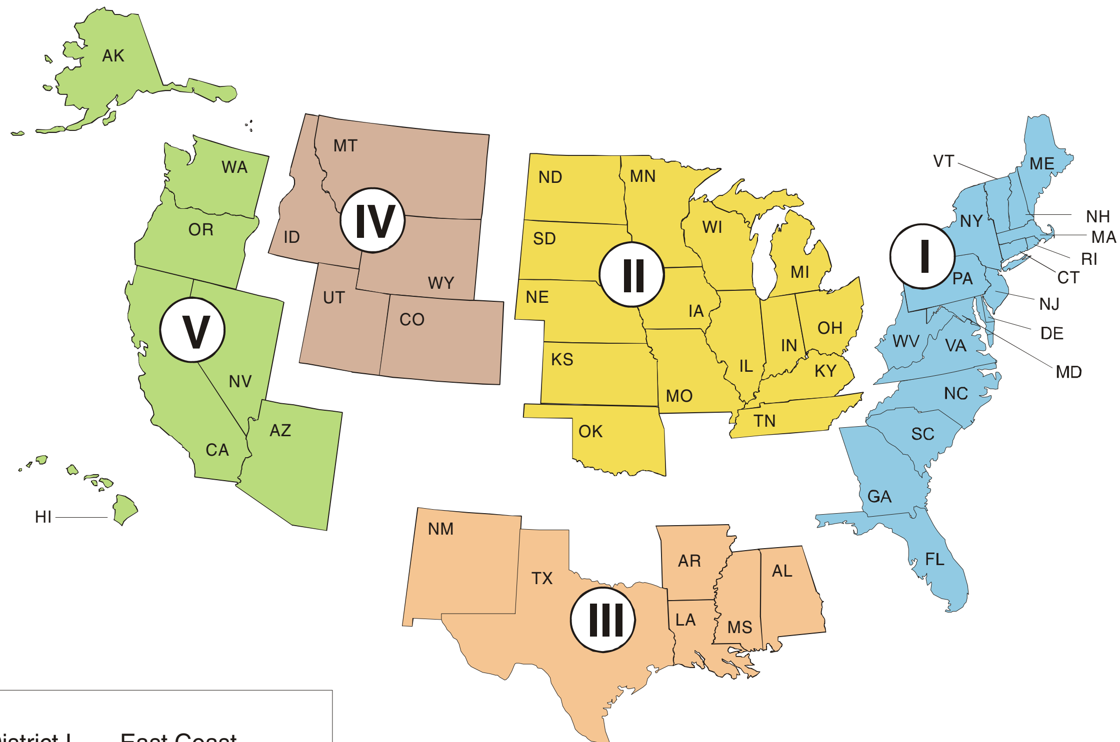
Source: Energy Information Administration. Office of Integrated Analysis and Forecasting.

F4. Natural Gas Transmission and Distribution Model Regions



Source: Energy Information Administration. Office of Integrated Analysis and Forecasting.

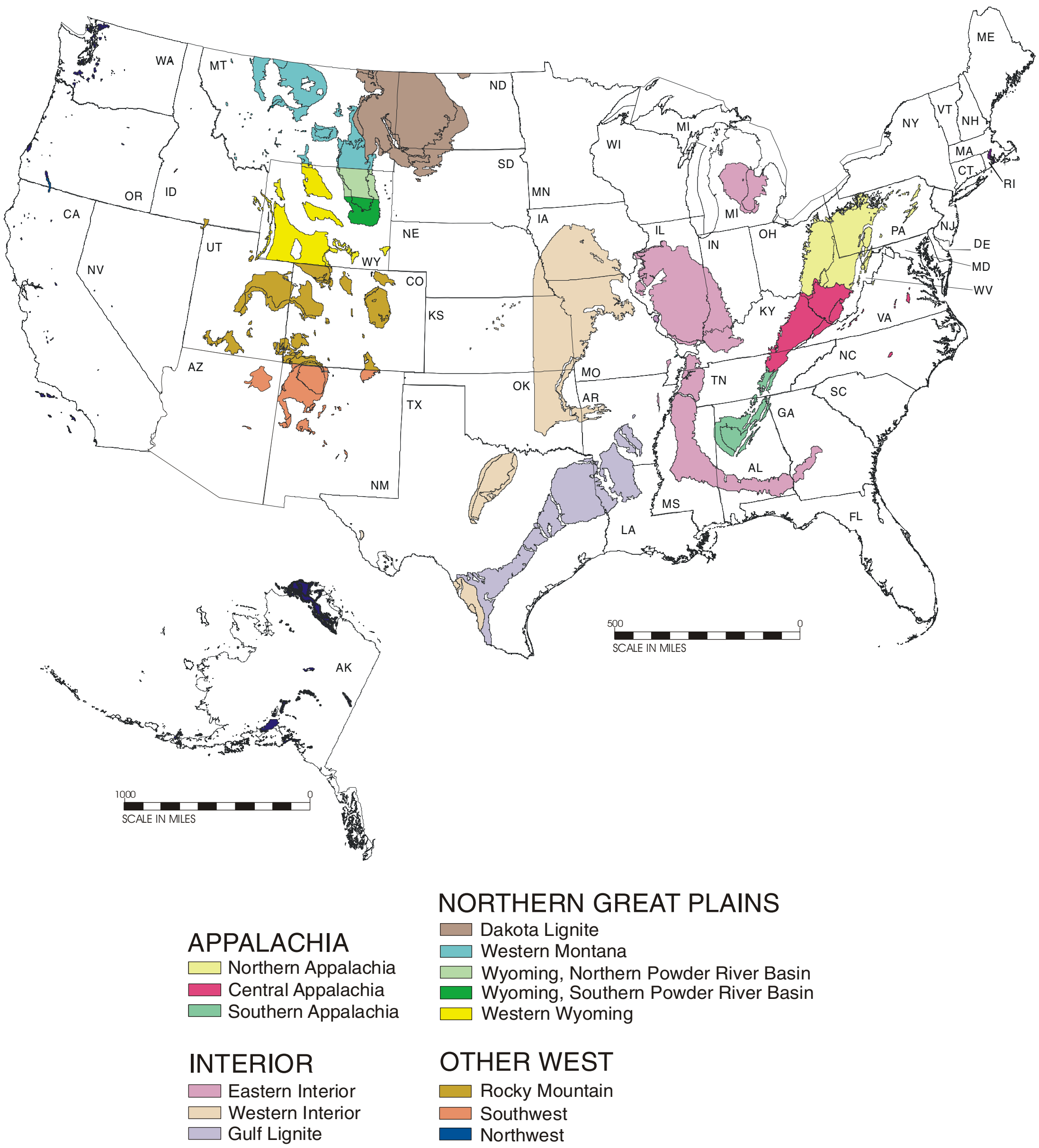
F5. Petroleum Administration for Defense Districts



PAD District I - East Coast
PAD District II - Midwest
PAD District III - Gulf Coast
PAD District IV - Rocky Mountain
PAD District V - West Coast

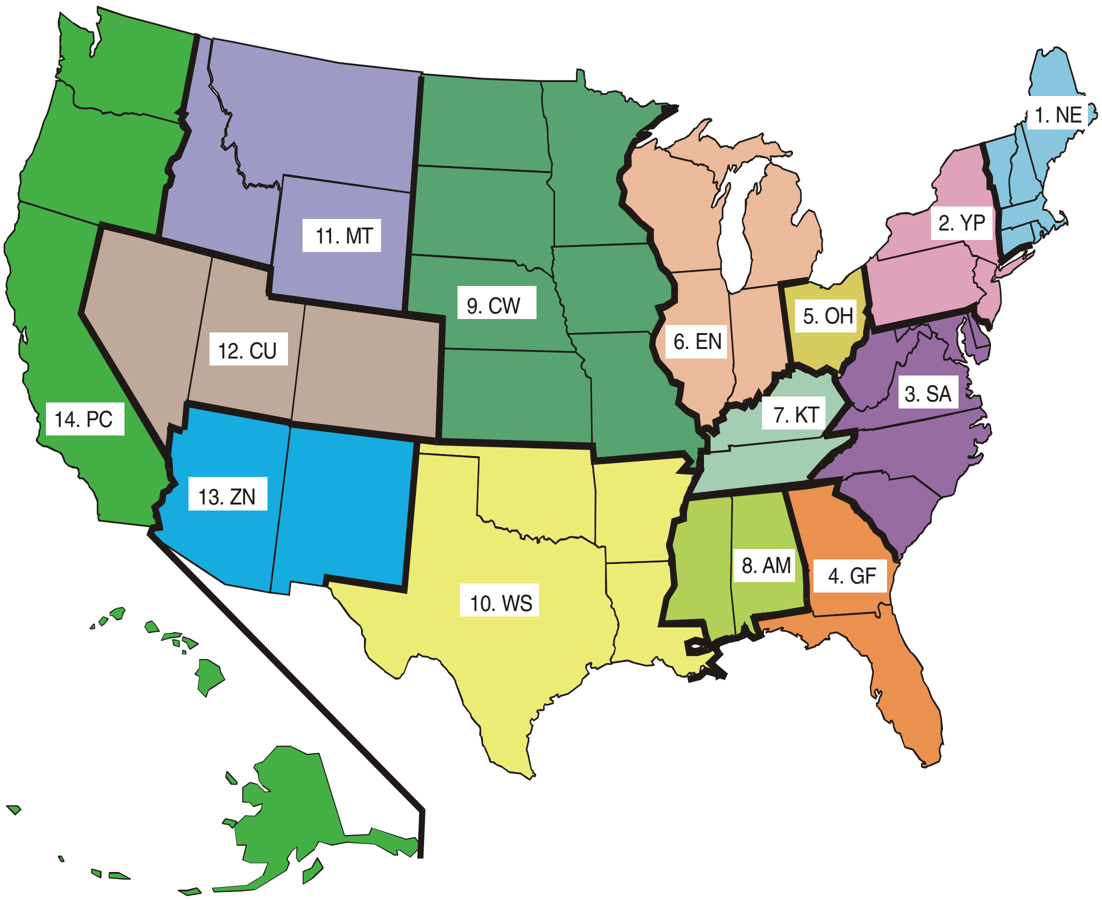
Source: Energy Information Administration. Office of Integrated Analysis and Forecasting.

F6. Coal Supply Regions



Source: Energy Information Administration. Office of Integrated Analysis and Forecasting.

F7. Coal Demand Regions



Region Code	Region Content
1. NE	CT,MA,ME,NH,RI,VT
2. YP	NY,PA,NJ
3. SA	WV,MD,DC,DE,VA,NC,SC
4. GF	GA,FL
5. OH	OH
6. EN	IN,IL,MI,WI
7. KT	KY,TN

Region Code	Region Content
8. AM	AL,MS
9. CW	MN,IA,ND,SD,NE,MO,KS
10. WS	TX,LA,OK,AR
11. MT	MT,WY,ID
12. CU	CO,UT,NV
13. ZN	AZ,NM
14. PC	AK,HI,WA,OR,CA

Source: Energy Information Administration. Office of Integrated Analysis and Forecasting.

Conversion Factors

Table G1. Heat Rates

Fuel	Units	Approximate Heat Content
Coal[1]		
Production	million Btu per short ton	20.341
Consumption	million Btu per short ton	20.165
Coke Plants	million Btu per short ton	26.325
Industrial	million Btu per short ton	22.312
Residential and Commercial	million Btu per short ton	21.235
Electric Power Sector	million Btu per short ton	19.911
Imports	million Btu per short ton	25.066
Exports	million Btu per short ton	25.524
Coal Coke	million Btu per short ton	24.800
Crude Oil		
Production	million Btu per barrel	5.800
Imports[1]	million Btu per barrel	5.981
Liquids		
Consumption[1]	million Btu per barrel	5.337
Motor Gasoline[1]	million Btu per barrel	5.157
Jet Fuel	million Btu per barrel	5.670
Distillate Fuel Oil[1]	million Btu per barrel	5.780
Diesel Fuel[1]	million Btu per barrel	5.769
Residual Fuel Oil	million Btu per barrel	6.287
Liquefied Petroleum Gases[1]	million Btu per barrel	3.591
Kerosene	million Btu per barrel	5.670
Petrochemical Feedstocks[1]	million Btu per barrel	5.562
Unfinished Oils	million Btu per barrel	6.118
Imports[1]	million Btu per barrel	5.558
Exports[1]	million Btu per barrel	5.745
Ethanol	million Btu per barrel	3.539
Biodiesel	million Btu per barrel	5.376
Natural Gas Plant Liquids		
Production[1]	million Btu per barrel	3.701
Natural Gas[1]		
Production, Dry	Btu per cubic foot	1,028
Consumption	Btu per cubic foot	1,028
End-Use Sectors	Btu per cubic foot	1,028
Electric Power Sector	Btu per cubic foot	1,028
Imports	Btu per cubic foot	1,025
Exports	Btu per cubic foot	1,009
Electricity Consumption	Btu per kilowatthour	3,412

[1]Conversion factor varies from year to year. The value shown is for 2007.
Btu = British thermal unit.
Sources: Energy Information Administration (EIA), *Annual Energy Review 2007*, DOE/EIA-0384(2007) (Washington, DC, June 2008), and EIA, AEO2009 National Energy Modeling System run AEO2009.D120908A.