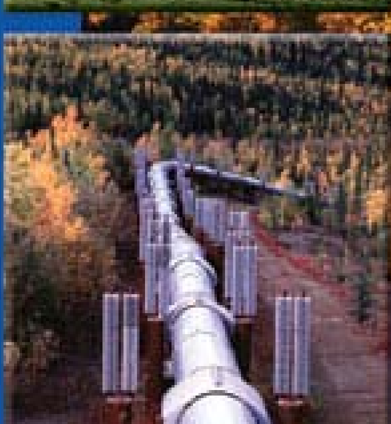
Annual Energy Outlook 2010

With Projections to 2035



U.S. Energy Information Administration

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April 2010

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For Further Information . . .

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The *Annual Energy Outlook 2010* 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 2010* during 2010.

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Preface

The *Annual Energy Outlook 2010* (*AEO2010*), prepared by the U.S. Energy Information Administration (EIA), presents long-term projections of energy supply, demand, and prices through 2035, based on results from EIA's National Energy Modeling System (NEMS). EIA published an "early release" version of the *AEO2010* Reference case in December 2009.

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 legislative and regulatory issues, including a summary of recently enacted legislation, such as the American Recovery and Reinvestment Act of 2009 (ARRA). The next section, "Issues in Focus," contains discussions of selected energy topics. The first discussion provides a comparison of the results in two cases that adopt different assumptions about the future course of existing policies: one case assumes the extension of a selected group of existing public policies—corporate average fuel economy (CAFE) standards, appliance standards, production tax credits (PTCs), and the elimination of sunset provisions in existing energy policies; the other case assumes only the elimination of sunset provisions. Other discussions include: end-use energy efficiency trends; the sensitivity of the projection results to variations in assumptions about the size of the U.S. shale gas resource; the implications of retiring nuclear plants after 60 years of operation; the relationship between natural gas and oil prices; and the basis for world oil price and production trends in *AEO2010*.

The "Market Trends" section summarizes the projections for energy markets. The analysis in *AEO2010* 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.

AEO2010 projections are based on Federal, State, and local laws and regulations in effect as of the end of October 2009. 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.

AEO2010 is published in accordance with Section 205c of the U.S. 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 by EIA are not statements of what will happen but of what might happen, given the assumptions and methodologies used for any particular scenario. The Reference case projection is a business-as-usual trend estimate, given known technology and technological and demographic trends. EIA explores the impacts of alternative assumptions in other scenarios with different macroeconomic growth rates, world oil prices, and rates of technology progress. The main cases in *AEO2010* generally assume that current laws and regulations are maintained throughout the projections. Thus, the projections provide policy-neutral baselines that can be used to analyze policy initiatives.

While energy markets are complex, energy 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 *AEO2010* 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

In 2009, U.S. energy markets continued to show the impacts of the economic downturn that began in late 2007. After falling by 1 percent in 2008, total electricity generation dropped by another 3 percent in 2009. Although other factors, including weather, contributed to the decrease, it was the first time in the 60-year data series maintained by the EIA that electricity use fell in two consecutive years. Over the next few years, the key factors influencing U.S. energy markets will be the pace of the economic recovery, any lasting impacts on capital-intensive energy projects from the turmoil in financial markets, and the potential enactment of legislation related to energy and the environment.

The projections in *AEO2010* focus on the factors that shape U.S. energy markets in the long term. Under the assumption that current laws and regulations remain unchanged throughout the projections, the *AEO2010* Reference case provides the basis for examination and discussion of energy market trends and the direction they may take in the future. It also serves as a starting point for the analysis of potential changes in energy policies, rules, or regulations. Unless otherwise noted, results refer to the Reference case. But *AEO2010* is not limited to the Reference case. It also includes 38 sensitivity cases (see Appendix E, Table E1, on page 201), which explore important areas of market, technological, and policy uncertainty in the U.S. energy economy.

Key results highlighted in *AEO2010* include moderate growth in energy consumption, increased use of renewables, declining reliance on imported liquid fuels, strong growth in shale gas production, and projected slow growth in energy-related carbon dioxide (CO_2) emissions in the absence of new policies designed to mitigate greenhouse gas (GHG) emissions.

AEO2010 also includes in-depth discussions on topics of special interest that may affect the energy market outlook. They include: impacts of the continuing renewal and updating of Federal and State laws and regulations; end-use energy efficiency trends in the *AEO2010* Reference case; the sensitivity of projections to alternative assumptions about U.S. shale gas development; the implications of retiring nuclear plants after 60 years of operation; the relationship between natural gas and oil prices in U.S. markets; and the basis for world oil price and production trends in *AEO2010*. Some of the highlights from those discussions are mentioned in this Executive Summary. Readers interested in more detailed analyses and discussions should refer to the "Legislation and Regulations" and "Issues in Focus" sections of this report.

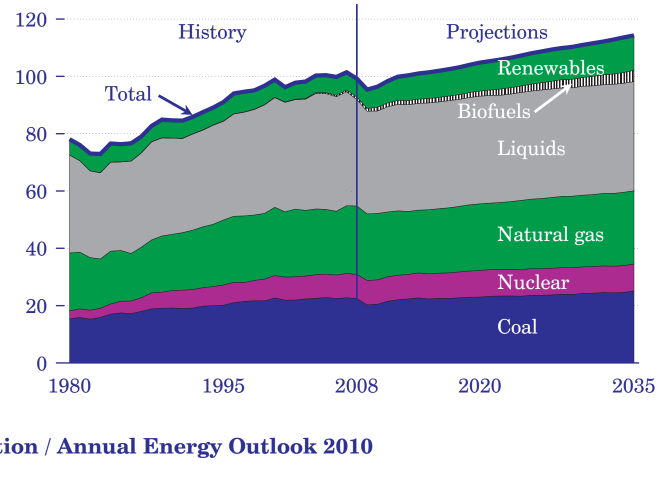
Moderate energy consumption growth and greater use of renewables

Total U.S. primary energy consumption increases by 14 percent from 2008 to 2035 in the Reference case (Figure 1), representing an average annual growth rate of 0.5 percent—only one-fifth of the projected 2.4-percent annual growth rate of the Nation's economic output. The difference between the two rates is the result of continuing improvement in the energy intensity of the U.S. economy, measured as the amount of energy consumed per dollar of gross domestic product (GDP). From 2008 to 2035, energy intensity falls by 1.9 percent per year in the Reference case, as the most rapid growth in the U.S. economy occurs in the less energy-intensive service sectors, and as the efficiency of energy-consuming appliances, vehicles, and structures improves.

EIA projects the strongest growth in fuel use for the renewable fuels used to generate electricity and to produce liquid fuels for the transportation sector. The growth in consumption of renewable fuels is primarily a result of Federal and State programs—including the Federal renewable fuels standard (RFS), various State renewable portfolio standard (RPS) programs, and funds in ARRA—together with rising fossil fuel prices. Although fossil fuels continue to provide most of the energy consumed in the United States over the next 25 years in the Reference case, their share of overall energy use falls from 84 percent in 2008 to 78 percent in 2035.

The role of renewables could grow still further if current policies that support renewable fuels are

Figure 1. U.S. primary energy consumption, 1980-2035 (quadrillion Btu)



extended. For example, the Reference case assumes that the PTC available for electricity generation from renewables sunsets in 2012 (wind) or 2013 (other technologies) as specified in current law, but it has a history of being renewed and could be extended again. In the Reference case, renewable generation accounts for 45 percent of the increase in total generation from 2008 to 2035. In alternative cases assuming the PTC for renewable generation is extended through 2035, the share of growth in total generation accounted for by renewables is between 61 and 65 percent.

Declining reliance on imported liquid fuels

Although U.S. consumption of liquid fuels continues to grow over the next 25 years in the *AEO2010* Reference case, reliance on petroleum imports decreases (Figure 2). With government policies and rising oil prices providing incentives for the continued development and use of alternatives to fossil fuels, biofuels account for all the growth in liquid fuel consumption in the United States over the next 25 years, while consumption of petroleum-based liquids is essentially flat. Total U.S. consumption of liquid fuels, including both fossil fuels and biofuels, rises from about 20 million barrels per day in 2008 to 22 million barrels per day in 2035 in the Reference case.

The role played by petroleum-based liquids could be further challenged if electric or natural-gas-fueled vehicles begin to enter the market in significant numbers. Rising oil prices, together with growing concerns about climate change and energy security, are leading to increased interest in alternative-fuel vehicles (AFVs), but both electric and natural gas vehicles face significant challenges. Alternative cases in this report examine the possible impacts of policies aimed at increasing natural gas use in heavy trucks and identify some of the key factors that will determine the potential for petroleum displacement.

Shale gas drives growth in natural gas production, offsetting declines in other sources

The growth in shale gas production in recent years is one of the most dynamic stories in U.S. energy markets. A few years ago, most analysts foresaw a growing U.S. reliance on imported sources of natural gas, and significant investments were being made in regasification facilities for imports of liquefied natural gas (LNG). Today, the biggest questions are the size of the shale gas resource base (which by most estimates is vast), the price level required to sustain its development, and whether there are technical or environmental factors that might dampen its development. Beyond those questions, the level of future domestic natural gas production will also depend on the level of natural gas demand in key consuming sectors, which will be shaped by prices, economic growth, and policies affecting fuel choice.

In the Reference case, total domestic natural gas production grows from 20.6 trillion cubic feet in 2008 to 23.3 trillion cubic feet in 2035. With technology improvements and rising natural gas prices, natural gas production from shale formations grows to 6 trillion cubic feet in 2035, more than offsetting declines in other production. In 2035, shale gas provides 24 percent of the natural gas consumed in the United States, up from 6 percent in 2008 (Figure 3).

Alternative cases in *AEO2010* examine the potential impacts of more limited shale gas development and of more extensive development of a larger resource base. In those cases, overall domestic natural gas production varies from 17.4 trillion cubic feet to 25.9 trillion

Figure 2. U.S. liquid fuels supply, 1970-2035 (million barrels per day)

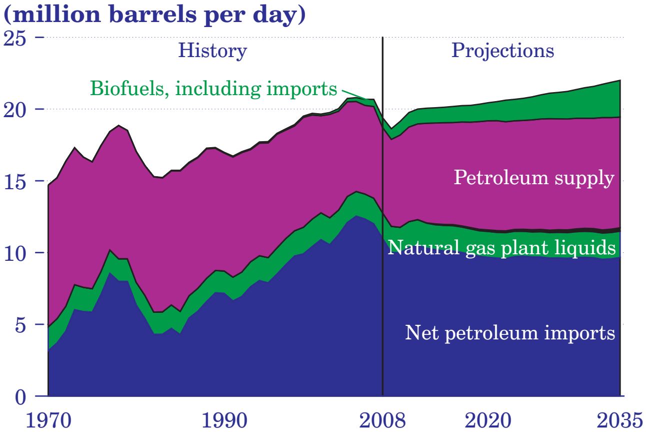
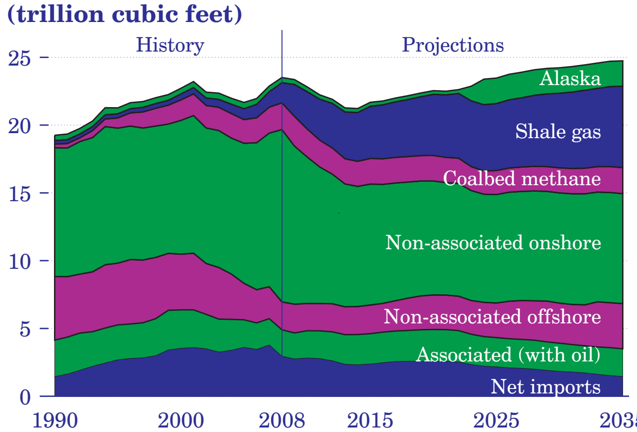


Figure 3. U.S. natural gas supply, 1990-2035 (trillion cubic feet)



cubic feet in 2035, compared with 23.3 trillion cubic feet in the Reference case. The wellhead price of natural gas in 2035 ranges from $6.92 per thousand cubic feet to $9.87 per thousand cubic feet in the alternative cases, compared with $8.06 per thousand cubic feet in the Reference case.

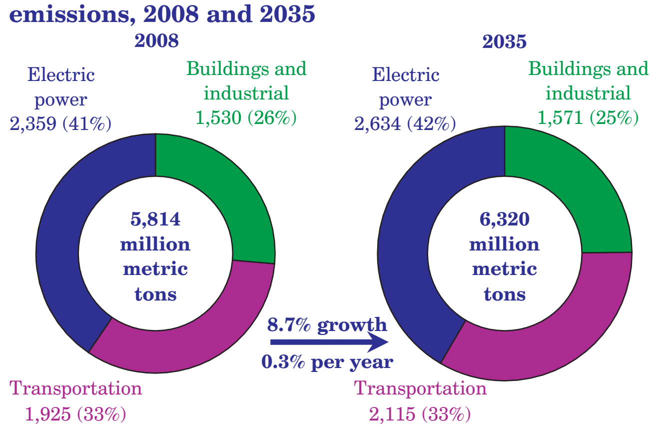
There also are uncertainties about the potential role of natural gas in various sectors of the economy. In recent years, total natural gas use has been increasing, with a decline in the industrial sector more than offset by growing use for electricity generation. In the long run, the use of natural gas for electricity generation continues growing in the Reference case. However, over the next few years the combination of relatively slow growth in total demand for electricity, strong growth in generation from renewable sources, and the completion of a number of coal-fired power plants already under construction limits the potential for increased use of natural gas in the electric power sector. The near- to mid-term downturn could be offset, of course, if policies were enacted that made the use of coal for electricity generation less attractive, if the recent growth in renewable electricity slowed, or if policies were enacted to make the use of natural gas in other sectors, such as transportation, more attractive.

Increases in energy-related carbon dioxide emissions slow

The combination of modest growth in energy consumption and increasing reliance on renewable fuels contributes to slow projected growth in U.S. CO_2 emissions. (For purposes of the *AEO2010* analysis, biomass energy consumption is assumed to be CO_2 neutral.) In the Reference case, which assumes no explicit regulations to limit GHG emissions beyond the recent vehicle GHG standards, CO_2 emissions from energy grow on average by 0.3 percent per year from 2008 to 2035, or a total of about 9 percent. To put the numbers in perspective, population growth is projected to average 0.9 percent per year, overall economic growth 2.4 percent per year, and growth in energy use 0.5 percent per year over the same period. Although total energy-related CO_2 emissions increase from 5,814 million metric tons in 2008 to 6,320 million metric tons in 2035 in the Reference case, emissions per capita fall by 0.6 percent per year. Most of the growth in CO_2 emissions in the *AEO2010* Reference case is accounted for by the electric power and transportation sectors (Figure 4).

The projections for CO_2 emissions are sensitive to many factors, including economic growth, policies aimed at stimulating renewable fuel use or low-carbon power sources, and any policies that may be enacted to reduce GHG emissions. In the *AEO2010* Low and High Economic Growth cases, projections for total primary energy consumption in 2035 are 104 quadrillion British thermal units (Btu) (9.5 percent below the Reference case) and 127 quadrillion Btu (10.7 percent above the Reference case), and projections for energy-related CO_2 emissions in 2035 are 5,768 million metric tons (8.7 percent below the Reference case) and 6,865 million metric tons (8.6 percent above the Reference case), respectively.

Figure 4. U.S. energy-related carbon dioxide emissions, 2008 and 2035



Legislation and Regulations

Legislation and Regulations

Introduction

The Reference case projections in *AEO2010* generally assume that current laws and regulations affecting the energy sector remain unchanged throughout the projection period (including the implication that laws which include sunset dates do, in fact, become ineffective at the time of those sunset dates). The potential impacts of pending or proposed legislation, regulations, and standards—or of sections of legislation that have been enacted but that require regulations for which the implementing agency will exercise major discretion, or require appropriation of funds that are not provided or specified in the legislation itself—are not reflected in the Reference case projections. However, sensitivity cases that incorporate alternative assumptions about the future of existing policies subject to periodic updates also are included. The Federal and State laws and regulations included in *AEO2010* are based on those in effect as of the end of October 2009. In addition, at the request of the Administration and Congress, EIA has regularly examined the potential implications of proposed legislation in Service Reports (see box on page 7).

Examples of Federal and State legislation that has been enacted over the past few years and incorporated in earlier *Annual Energy Outlooks* (*AEO*s) include:

- The provisions of the ARRA (Public Law 111-5), enacted in mid-February 2009 [*1*]. ARRA provides significant new Federal funding, loan guarantees, and tax credits to stimulate investments in energy efficiency and renewable energy (see details below).
- The tax provisions of the Energy Improvement and Extension Act of 2008 (EIEA2008), signed into law on October 3, 2008, as part of Public Law 110-343, the Emergency Economic Stabilization Act of 2008 [*2*], which extends the residential and business tax credits for renewable energy; removes the cap on the tax credit for purchases of residential solar photovoltaic (PV) installations; increases the tax credit for residential ground-source heat pumps; adds a business investment tax credit (ITC) for combined heat and power (CHP), small wind systems, and commercial ground-source heat pumps; creates a tax credit for the purchase of new, qualified, plug-in electric drive motor vehicles; extends the income and excise tax credits for biodiesel and renewable diesel to the end of 2009 and increases the amount of the tax credit for biodiesel and renewable diesel produced from recycled feedstock; establishes a tax credit for the production of liquid petroleum gas, LNG, compressed natural gas (CNG), and aviation fuels from biomass; creates an additional tax credit for the elimination of CO_2 emissions that would otherwise be released into the atmosphere in enhanced oil recovery (EOR) and non-EOR operations; extends and modifies key renewable energy tax provisions that were scheduled to expire at the end of 2008, including PTCs for wind, geothermal, landfill gas, and certain biomass and hydroelectric facilities; and expands 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 biofuel provisions of the Food, Conservation, and Energy Act of 2008 (Public Law 110-234) [*3*], 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.
- The provisions of the Energy Independence and Security Act of 2007 (EISA2007, Public Law 110-140), including: an RFS requiring the use of 36 billion gallons of biofuels 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.
- State RPS programs, representing laws and regulations of 30 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 have been considered in earlier *AEO*s, include the following:

- Decision by the U.S. Court of Appeals for the District of Columbia Circuit on December 23, 2008, to remand, but not vacate, the Clean Air Interstate Rule (CAIR) [*4*]. The decision, which overrides a previous decision by the D.C. Circuit Court on February 8, 2008, to vacate and remand

CAIR, allows CAIR to remain in effect, and provides time for the U.S. Environmental Protection Agency (EPA) to modify CAIR to address the objections raised by the Court in its earlier decision while leaving the rule in place (see details below).

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

Detailed information on more recent Federal and State legislative and regulatory developments that are considered in *AEO2010* is provided below.

American Recovery and Reinvestment Act of 2009: Summary of provisions

ARRA, signed into law in mid-February 2009, provides significant new Federal funding, loan guarantees, and tax credits to stimulate investments in energy efficiency and renewable energy. The provisions of ARRA were incorporated initially as part of a revision to the *AEO2009* Reference case that was released in April 2009 [*5*], and they also are included in *AEO2010*. However, provisions that require

EIA Service Reports released since January 2009

The table below summarizes EIA Service Reports completed in 2009. Those reports, and others that were completed before 2009, 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
Energy Market and Economic Impacts of H.R. 2454, the American Clean Energy and Security Act of 2009	August 2009	Congressmen Henry Waxman and Edward Markey	www.eia.gov/oiaf/servicerpt/hr2454/index.html	Analysis of H.R. 2454, the American Clean Energy and Security Act of 2009 (ACESA). ACESA, as passed by the House of Representatives on June 26, 2009, is a bill that regulates emissions of greenhouse gases through market-based mechanisms, efficiency programs, and economic incentives.
Impacts of a 25-Percent Renewable Electricity Standard as Proposed in the American Clean Energy and Security Act Discussion	April 2009	Congressman Edward Markey	www.eia.doe.gov/oiaf/servicerpt/acesa/pdf/sroiaf(2009)04.pdf	Analysis of a 25-percent Federal renewable electricity standard (RES). The RES proposal analyzed in this report is included in the discussion draft of broader legislation—ACESA, issued on the Energy and Commerce Committee web site at the end of March 2009. The analysis presented in this report starts from an updated version of the *Annual Energy Outlook 2009* (*AEO2009*) Reference case, which reflects the projected impacts of the ARRA, enacted in February 2009, and revised economic assumptions.
An Updated *Annual Energy Outlook 2009* Reference Case Reflecting Provisions of the American Recovery and Reinvestment Act and Recent Changes in the Economic Outlook	April 2009	NA	www.eia.doe.gov/oiaf/servicerpt/stimulus/pdf/sroiaf(2009)03.pdf	Updates the *AEO2009* Reference case released in December 2008, based on recently enacted legislation and the changing macroeconomic environment.
Light-Duty Diesel Vehicles: Efficiency and Emissions Attributes and Market Issues	February 2009	Senator Jeff Sessions	www.eia.doe.gov/oiaf/servicerpt/lightduty/pdf/sroiaf(2009)02.pdf	Analysis of the environmental and energy efficiency attributes of light-duty diesel vehicles. Specifically, the inquiry asked for a 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/pdf/sremeu(2009)01.pdf	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.

funding appropriations to be implemented, whose impact is highly uncertain, or that require further specification by Federal agencies or Congress, are not included. Moreover, *AEO2010* does not include any provision that addresses a level of detail beyond that modeled in NEMS.

This section provides a summary of the ARRA provisions and highlights those specific provisions incorporated in *AEO2010*, including:

- Weatherization and assisted housing programs
- Energy efficiency and conservation block grant programs
- State energy programs
- Tax credits for plug-in hybrid electric vehicles (PHEVs)
- Tax credits for electric vehicles
- Updated tax credits for renewables
- Loan guarantees for renewables and biofuels
- Support for carbon capture and storage (CCS)
- Smart grid expenditures.

The following discussion provides a summary of the ARRA provisions included in *AEO2010* 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 ARRA.

ARRA end-use demand provisions

Residential and commercial buildings

Many of the provisions of ARRA target energy efficiency and renewable energy use associated with residential and commercial buildings. Federal funding is provided to assist State and local governments in implementing energy efficiency programs; to improve energy efficiency and renewable energy use in Federal buildings and facilities; and to encourage renovations of schools and college facilities. ARRA also includes provisions that expand and revise tax credits for renewable and energy-efficient property purchased and installed in residential and commercial buildings.

Weatherization, assisted housing, and energy efficiency and conservation block grants

ARRA Title IV, "Energy and Water Development," allocates a total of $9.45 billion to weatherize and/or increase the energy efficiency of low-income housing and assist local governments in implementing energy efficiency programs, with a total of $4.75 billion specifically for weatherization. The regional impacts of weatherization funds are estimated on the basis of DOE's State allocation formula [*6*] and Oak Ridge National Laboratory's weatherization impact analysis. Local governments also are allowed, and assumed, to use some of the Conservation Block Grant funding for PV and wind turbine installations.

State energy programs

ARRA Title IV, "Energy and Water Development," allocates $3.1 billion for States to implement or enhance energy efficiency programs. Although the money can be spent on a variety of programs, Section 410 specifically mentions the adoption of building codes, citing the International Energy Conservation Code (IECC) 2009. To account for the impact of the funding in *AEO2010*, it is assumed that States will adopt and enforce the IECC 2006 code by 2011 and the IECC 2009 code by 2018. Likewise, States are assumed to adopt and enforce the ASHRAE 90.1-2007 standard for nonresidential construction by 2018. States and local governments also are assumed to use the 10-year Treasury Note rate (3.7 percent in 2011) when purchasing energy-using equipment for government-owned facilities during years when ARRA funding is available. It is also assumed that part of the funding for State energy programs will be used for PV and wind turbine installations.

Federal buildings and green schools

ARRA Division A allocates $4.5 billion to the U.S. General Services Administration (GSA) for measures to convert GSA facilities to high-performance green buildings, $2.3 billion for military construction, and $4.3 billion for U.S. Department of Defense (DOD) energy efficiency projects and modernization of facilities. Additional DOD funding is provided for energy efficiency technology demonstrations and research. Under the various titles included in ARRA, money is also allocated to virtually every major Federal agency for construction, repair, and/or modernization of facilities. To account for the funding in *AEO2010*, schools and Federal facilities are assumed to use the 10-year Treasury Note rate as a hurdle rate for new construction and replacement of equipment in years when ARRA funding is available. The 10-year Treasury Note rate already was assumed for new construction of Federal facilities, based on earlier legislation. ARRA funding also broadens its use to include replacement equipment as well. Photovoltaic installations, wind turbines, and fuel cells also are added where specified in expenditure plans.

Updated tax credits for renewables and energy-efficient technologies

ARRA Division B expands and revises tax credits for the purchase of renewable and energy-efficient property purchased and installed in residential and commercial buildings. Section 1103 removes the cap on the 30-percent business ITC for small wind property that was established in EIEA2008. Sections 1121 and 1122 extend by 1 year the tax credits for energy-efficient nonbusiness property while increasing the tax-deductible amount to $1,500. For renewable technologies, such as geothermal heat pumps and solar water heaters, the tax deductible amount is unlimited, up to 30 percent of the cost.

Transportation sector

ARRA contains several changes to the PHEV tax credit originally included in EIEA2008. Title I, "Tax Provisions," Section 1141, allows a $2,500 tax credit for the purchase of qualified PHEVs with battery capacity of at least 4 kilowatthours. Starting at a battery capacity of 5 kilowatthours, PHEVs earn an additional battery credit of $417 per kilowatthour, up to a maximum of $5,000. The maximum total PHEV credit that can be earned is capped at $7,500 per vehicle.

The PHEV tax credit eligibility and phaseout are tied to the sales of individual vehicle manufacturers. The credits are phased out once a manufacturer's cumulative sales of qualified vehicles reach 200,000. The phaseout period begins two calendar quarters after the first date in which a manufacturer's sales reach the cumulative sales maximum after December 31, 2009. The credit is reduced to 50 percent of its total value for the first two calendar quarters of the phaseout period, and then to 25 percent for the third and forth calendar quarters, before being phased out entirely thereafter. The credit applies to vehicles with gross vehicle weight rating (GVWR) less than 14,000 pounds. To capture the phaseout period in *AEO2010*, the PHEV tax credit has been incorporated across representative manufacturer groups.

ARRA Title I, "Tax Provisions," Section 1142, also allows a tax credit of 10 percent against the cost of a qualified electric vehicle with a battery capacity of at least 4 kilowatthours, subject to the same phaseout schedule applied to PHEVs. The new electric vehicle tax credit has also been incorporated in *AEO2010* by manufacturer group.

ARRA electricity provisions

ARRA establishes Federal loan guarantees for certain renewable fuel, biofuel, and electricity transmission projects. The provisions for renewable projects are included in the electricity modeling for *AEO2010*. ARRA also extends and modifies Federal tax credit incentives for new renewable generation capacity. The NEMS electricity module also represents the funding provided in ARRA for smart grid demonstration projects.

Extension of renewable production and investment tax credits

ARRA Division B, Title 1, "Tax Provisions," extends and significantly modifies the Federal tax credits for new renewable generation capacity. Before enactment of ARRA, wind, geothermal, landfill gas, and certain hydroelectric and biomass technologies were eligible to receive a PTC of up to 2.1 cents per kilowatthour generated over the first 10 years of plant operation [7]; wind was eligible to receive the PTC for plants constructed before January 1, 2010; and other eligible plants received the PTC if construction was completed before January 1, 2011. ARRA Section 1101 extends those in-service deadlines to January 1, 2013, for wind and January 1, 2014, for other eligible technologies.

In addition, under Section 1102, ARRA allows projects that are eligible for the PTC to instead receive a 30-percent ITC on plant investment costs. Section 1603 also allows the owners of projects choosing the ITC to receive the payment in the form of an after-tax grant of equivalent value rather than as a tax credit, which presumably will allow project owners with limited tax liabilities to claim the full value of the credit.

Solar technologies are not eligible for the ARRA PTC, but EIEA2008 established a 30-percent ITC for solar projects built through 2016, and the Energy Policy Act of 1992 provided a permanent 10-percent ITC.

AEO2010 incorporates the ARRA provisions cited above and generally assumes that renewable electricity projects will claim the more favorable tax credit or grant option available to them during the eligibility period. Provisions extending tax credits for marine-based technologies are not reflected in *AEO2010*, because EIA assumes that those technologies will not be in significant commercial use by 2035. ARRA also extends funding for Clean Renewable Energy Bonds (CREBs) used to fund renewable energy projects at publicly owned utilities that do not pay taxes and cannot take advantage of tax credits. Because *AEO2010* assumes that all new renewable capacity is developed and owned by taxable entities, CREBs are not included in NEMS.

Loan guarantees for renewables and transmission projects

ARRA Title IV, "Energy and Water Development," Section 406, provides $6 billion to pay the cost of guarantees for loans authorized by the Energy Policy Act of 2005 (EPACT2005). The purpose of the loan guarantees is to stimulate the deployment of conventional renewable technologies, conventional transmission technologies, and innovative biofuels technologies. To qualify, eligible projects must be under construction by September 30, 2011, meaning that projects with a long-term construction horizon are unlikely to qualify. The face value of the loans that may be guaranteed by the appropriation will depend on the subsidy costs assigned to the projects eventually selected. For example, if the average subsidy cost were 10 percent of the face value of the loans, the $6 billion appropriated would support loan guarantees on $60 billion of debt financing. The Section 406 provision is represented in *AEO2010* by a lower cost of financing (by 2 percentage points) for all eligible renewable projects brought on line by 2015. The 2015 date, 4 years after the September 30, 2011, cutoff date for start of construction, was chosen to allow for the construction period associated with most renewable generating technologies.

Smart grid expenditures

ARRA Title IV, "Energy and Water Development," Section 405, provides $4.5 billion to modernize, secure, and improve the reliability of electric energy and storage infrastructure and to develop a Smart Grid. While somewhat difficult to define, smart grid technologies generally include a wide array of storage, measurement, communications, and control equipment employed throughout the generation, transmission, and distribution system to enable real-time monitoring of the production, flow, and use of power from generator to consumer. Among other things, smart grid technologies, once deployed, are expected to enable more efficient use of the transmission and distribution grid and lower line losses, facilitate greater use of renewables, and provide information to utilities and their customers that will lead to greater investment in energy efficiency and reduction of peak load demands. The funds provided will not cover the cost of widespread implementation of smart grid technologies but could stimulate more rapid investment than otherwise would occur.

Several changes were made throughout NEMS to represent the impacts of the smart grid funding provided in ARRA. For the electricity module, it was assumed that line losses would decrease slightly, peak loads would fall as customers shifted their usage patterns, and customers would be more responsive to price signals. Historically, line losses (expressed as the percentage of electricity lost in transmission) have fallen as utilities have made investments to expand the grid or replace aging or failing equipment. That trend was incorporated in previous *AEO* Reference cases. After passage of ARRA, the time period for improvements was extended, allowing for greater declines in line losses. *AEO2010* assumes that line losses will be reduced from roughly 6.9 percent in 2008 to 5.3 percent in 2025.

Smart grid technologies also have the potential to reduce peak demand through the increased deployment of demand response programs. *AEO2010* assumes that efforts stimulated by Federal expenditures on smart grid technologies will reduce peak demands in 2035 by 3 percent from what they otherwise would be. Because the load shifted to off-peak hours is not eliminated, net energy consumed remains largely constant.

It is also assumed that increased investment in smart grid technologies—particularly, smart meters on buildings and homes—will make consumers more responsive to changes in electricity prices. Accordingly, the price elasticity of demand for residential and commercial electricity is increased for certain uses.

Coal

ARRA Title IV, "Energy and Water Development," provides $3.4 billion for additional research and development of fossil energy technologies, including $800 million to fund projects under the Clean Coal Power Initiative program focusing on capture and sequestration of GHGs [*8*]. In July 2009, a total of $408 million was allocated to two projects—the Basin Electric Power Cooperative's Antelope Valley Station in North Dakota and the Hydrogen Energy Project in California—to demonstrate the capability to capture 3 million tons of CO_2 per year. In December 2009, two additional project awards were announced through the Clean Coal Power Initiative program, which will be funded in part through ARRA. The projects include American Electric Power's Mountaineer plant in West Virginia (235-megawatt flue gas stream) and a new plant to be built by Summit Texas Clean Energy in Texas. To reflect the impact of this provision, the *AEO2010* Reference case assumes that an additional 1 gigawatt of coal-fired capacity with CCS will be built by 2017.

Other ARRA provisions

Additional appropriations under ARRA Title IV, totaling \$2.6 billion, are not included in *AEO2010*, because the activities funded have only indirect or unknown impacts on energy use, or because insufficient program detail has been provided. The additional appropriations include \$1 billion for research and development projects to be established by the Secretary of Energy; \$80 million for geologic sequestration projects covering site characterization, training, research grants, and other administrative costs; and \$1.52 billion for industrial carbon capture and energy efficiency projects or those developing innovative uses for CO_2. As of October 2009, \$112 million of the \$1.52 billion had been allocated to 14 industrial projects demonstrating various combinations of carbon capture technologies, CO_2 transport activities, sequestration, and EOR.

Liquid fuels taxes and tax credits

This section provides a review of the treatment of Federal fuels taxes and tax credits in *AEO2010*.

Excise taxes on highway fuel

The treatment of Federal highway fuel taxes remains unchanged from the previous year's *AEO*. Gasoline is taxed at 18.4 cents per gallon, diesel fuel at 24.4 cents per gallon, and jet fuel at 4.4 cents per gallon, consistent with current laws and regulations. Consistent with Federal budgeting procedures, which dictate that excise taxes dedicated to a trust fund, if expiring, are assumed to be extended at current rates, these taxes are maintained at their present levels, without adjustment for inflation, throughout the projection [*9*]. State fuel taxes are calculated on the basis of a volume-weighted average for diesel, gasoline, and jet fuels. The State fuel taxes were updated as of July 2009 [*10*] and are held constant in real terms over the projection period, consistent with historical experience.

Biofuels tax credits and tariffs

No changes have been made in the treatment of biofuels taxes and credits in *AEO2010*. The existing ethanol excise tax credit of \$0.45 per gallon, as specified in the Food, Conservation, and Energy Act of 2008 [*11*], is still scheduled to expire at the end of 2010. In addition, the PTC of \$1.01 per gallon for cellulosic biofuels [*12*], also specified in the Food, Conservation, and Energy Act of 2008, remains set to expire on January 1, 2013.

The \$1.00-per-gallon excise tax credit for biodiesel established in the Emergency Economic Stabilization Act of 2008 [*13*] expired on December 31, 2009. The credit applies to biodiesel made from recycled vegetable oils or recycled animals fats, as well as renewable diesel (e.g., diesel derived from biomass).

Low-carbon fuel standard

In April 2009, the CARB passed the world's first low-carbon fuel standard (LCFS), which is scheduled to go into effect on January 1, 2011 [*14*]. Because the rules for the LCFS had not been finalized as of October 2009, they are not included in *AEO2010*. The regulation aims to reduce the carbon content of transportation fuels sold in California by 10 percent in 2020. The reductions will be applied to gasoline and diesel fuel pools, as well as a number of their substitutes as defined by CARB's eligible fuel pathways [*15*], with providers of transportation fuels being the regulated parties. Regulated parties will be able to meet the LCFS by using a combination of fuel blends, alternative fuels, and LCFS credits. By the end of 2010, the baseline carbon intensities for gasoline, diesel fuel, and their substitutes will be calculated and finalized in a full-life-cycle fuel analysis, which will consider indirect land-use effects for certain biofuels.

CAFE standards

Pursuant to the President's announcement of a National Fuel Efficiency Policy, the National Highway Traffic Safety Administration (NHTSA) and the EPA have promulgated nationally coordinated standards for tailpipe CO_2-equivalent emissions and fuel economy for light-duty vehicles (LDVs) [*16*], which includes both passenger cars and light-duty trucks. In the joint rulemaking, EPA is enacting CO_2-equivalent emissions standards under the Clean Air Act (CAA), and NHTSA is enacting companion CAFE standards under the Energy Policy and Conservation Act, as amended by EISA2007.

The initial harmonized standards will affect model year (MY) 2012 vehicles, and compliance requirements will increase in stringency through MY 2016, building on NHTSA's enacted CAFE standard for MY 2011. NHTSA has estimated the impact of the new CAFE standards and has projected that the proposed fleet-wide standards for LDVs will increase fuel economy from 27.3 mpg in MY 2011 to 34.1 mpg in MY 2016, an average annual increase of 4.3 percent. EPA projects a fleet-wide reduction in CO_2-equivalent emissions from 295 grams per mile for MY 2011 to 250 grams per mile for MY 2016 (Table 1).

Although the two separate standards were issued jointly, there are important differences between them. In lieu of increasing vehicle fuel economy, EPA's vehicle CO_2-equivalent emissions standard allows manufacturers to generate CO_2-equivalent credits by reducing emissions of hydrofluorocarbons by improving air conditioner systems and alternative fuel use capabilities. NHTSA estimates that adoption of cost-effective technologies will enable manufacturers to achieve a fleet-wide minimum fuel economy requirement of 34.1 mpg by 2016. Because the CO_2-equivalent standards cover all vehicle emissions related to GHGs, manufacturers who do not implement technologies that address non-fuel-related emissions will have to comply with a fuel economy standard of 35.5 mpg by 2016.

The fuel standards use an attribute-based methodology to determine the minimum fuel economy requirements and CO_2-equivalent emissions standards for vehicles based on footprint, 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) in square feet.

Table 1. Estimated average fleet-wide fuel economy and CO_2-equivalent emissions compliance levels, model years 2012-2016

Model year	Passenger car	Light truck	Combined
NHTSA CAFE standard (miles per gallon)			
2012	33.3	25.4	29.7
2013	34.2	26.0	30.5
2014	34.9	26.6	31.3
2015	36.2	27.5	32.6
2016	37.5	28.8	34.1
EPA CO_2-equivalent emissions standard (grams per mile)			
2012	263	346	295
2013	256	337	286
2014	247	326	276
2015	236	312	263
2016	225	298	250

For example, a passenger car with a footprint of 44 square feet in MY 2016 will face a fuel economy standard of 38.8 mpg and a CO_2-equivalent emission standard of 218.6 grams per mile. Standards are revised in subsequent model years to ensure improvement in fuel economy and a reduction in CO_2-equivalent emissions over time. Separate mathematical functions are established for passenger cars and light trucks, reflecting their different design capabilities (Figures 5 and 6). As required by EISA2007, *AEO2010* assumes that CAFE standards will be increased, so that the combined fuel economy of new LDVs will achieve the required minimum of 35 mpg by 2020.

Manufacturer compliance is determined for CAFE by a harmonically weighted average of sales of cars and light trucks and for CO_2-equivalent emissions by a

Figure 5. Projected average fleet-wide fuel economy and CO_2-equivalent emissions compliance levels for passenger cars, model year 2016 (miles per gallon equivalent)

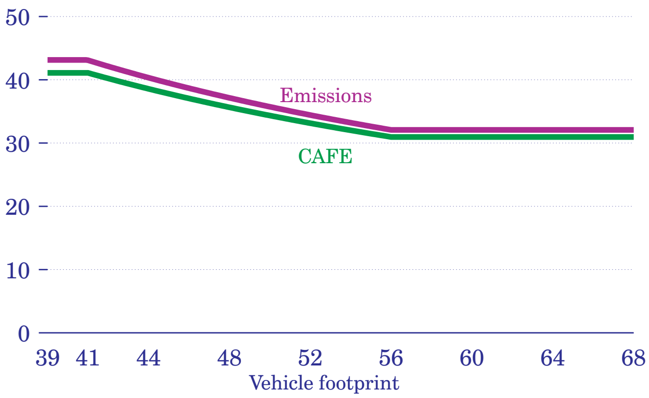
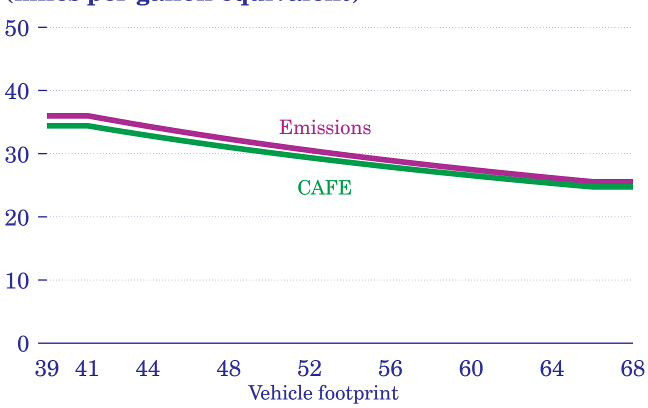


Figure 6. Projected average fleet-wide fuel economy and CO_2-equivalent emissions compliance levels for light trucks, model year 2016 (miles per gallon equivalent)



production-weighted average compliance across each manufacturer's fleet. Individual manufacturers face different CAFE and CO_2 equivalent compliance stringencies to the extent that their sales and production distributions differ by footprint.

The NHTSA-EPA standards also include flexibility provisions for compliance by individual manufacturers, such as: (1) allowing credit trading among manufacturers who exceed their standards and those who do not; (2) allowing credit transfers among vehicle fleets for a single manufacturer; (3) allowing manufacturers to "carry forward" credits earned from exceeding the standards in earlier model years and "carry back" credits earned in later years to meet shortfalls from earlier model years; and (4) allowing manufacturers to earn CAFE credits by producing AFVs, with credits for flex-fuel vehicles (FFVs) being phased out by MY 2019, and earn CO_2-equivalent credits for FFVs until MY 2015 unless the manufacturer can prove that the vehicle is actually using an alternative fuel. NHTSA and the EPA also differ in their compliance flexibility provisions, such as EPA's air conditioner credits and a temporary lead-time allowance for manufactures who sell fewer than 400,000 vehicles in MY 2009.

The flexibility provisions do not, however, allow manufacturers to deviate significantly from their annual fuel economy targets. NHTSA retains a required minimum fuel economy level for passenger cars. Before any credit can be applied by a manufacturer, its passenger car fleet 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 nondomestic passenger cars for that model year, whichever is higher. Based on NHTSA's current market projection, its estimate of the minimum standard is 34.8 mpg in 2016. It is important to note that EPA and NHTSA's joint proposal is subject to change in future rulemakings. Although the final CAFE standards have been enacted, only the proposed CAFE standards and compliance schedule were available when *AEO2010* was finalized. At that time, the proposal offered the best available insight into future regulations implementing EISA2007 CAFE requirements through 2016. *AEO2010* increases the MY 2016 fuel economy standards to ensure that the EISA2007 mandated minimum requirements are met through 2020.

New EPA guidelines for review of surface coal mining operations in Appalachia

On April 1, 2010, the EPA issued a set of new guidelines to several of its Regional offices regarding the compliance of surface coal mining operations in Appalachia with the provisions of the Clean Water Act (CWA), the National Environmental Policy Act, and the environmental justice Executive Order (E.O. 12898). The stated purpose of the guidance was to explain more fully the approach that the EPA will be following in permit reviews, and to provide additional assurance that its Regional offices use clear, consistent, and science-based standards in reviewing the permits. Although the new guidelines go into effect immediately, they will be subjected to review both by the public and by the EPA's Science Advisory Board, with a set of final guidelines to be issued no later than April 1, 2011.

Issuance of the new EPA guidelines is related primarily to the ongoing controversy over use of the mountaintop removal method at a number of surface coal mining operations in Central Appalachia—primarily in southern West Virginia and eastern Kentucky. Although the guidelines propose a more rigorous review for all new surface coal mines in Appalachia, the EPA indicates that the practice of valley fills, primarily associated with the mountaintop removal method, is the aspect of Appalachian coal mining that will be most scrutinized. In particular, the EPA points to new scientific evidence that dissolved solids in drainage from existing valley fills in Central Appalachia are adversely affecting downstream aquatic systems.

Although the proposed use of valley fills at mining sites will not necessarily preclude the issuance of permits for surface mines under CWA Sections 402 and 404, the EPA guidelines recommend that all practicable efforts be made to minimize their use. Section 402 of the CWA pertains to the issuance of National Pollution Discharge Elimination System permits. Section 404 relates to the issuance of permits for the discharge of dredge or fill material into the waters of the United States, including wetlands. Issuance of Section 404 permits comes under the authority of the U.S. Army Corps of Engineers, but is subject to EPA oversight.

Two recent actions by the EPA related to its review of Section 404 permits for proposed mountaintop mining operations in West Virginia indicate the agency's heightened concern with regard to valley fills. In January 2010, the EPA announced its approval for the issuance of a Section 404 permit for Patriot Coal's proposed Hobet 45 mountaintop mining operation. The EPA indicated that the company was able to eliminate the need for any valley fills and, as a result, reduce the estimated adverse downstream impact by 50 percent. In contrast, in March 2010, the EPA was not able to extend approval of a Section 404 permit for Arch Coal Company's proposed Spruce No. 1 mountaintop mining operation, because the mine plan proposed the burial of 7.5 miles of healthy headwater streams under the spoil of six separate valley fills.

The EPA's new guidelines for surface coal mining operations are not represented in the *AEO2010* projections, because they were issued after the cutoff date for model simulations. The likely impact of representing the more intensive reviews of new mining operations would be higher projected prices and lower production for surface-mined coal from Central Appalachia. In the *AEO2010* Reference case, coal production at surface mines in Central Appalachia is projected to decline from 115 million tons in 2008 to 71 million tons in 2020 and 63 million tons in 2035.

Clean Air Interstate Rule: Changes and modeling in *AEO2010*

On December 23, 2008, the D.C. Circuit Court remanded but did not vacate CAIR [*17*], overriding its previous decision on February 8, 2008, to remand and vacate CAIR. The December decision, which is reflected in *AEO2010*, allows CAIR to remain in effect, providing time for the EPA to modify the rule in order to address objections raised by the Court in its earlier decision. A similar rule, referred to as the CAMR, which was to set up a cap-and-trade system for reducing mercury emissions by approximately 70 percent, is not represented in the *AEO2010* projections, because it was vacated by the D.C. Circuit Court in February 2008.

CAIR, which was promulgated by the EPA in 2005, was designed to achieve further reductions in emissions of sulfur dioxide (SO_2) and nitrogen oxides (NO_x) beyond those established in the 1990 CAA Amendments. The emissions reductions mandated by the rule were put in place to assist States in meeting their National Ambient Air Quality Standards for ground-level ozone and particulate matter. The EPA identified 28 States and the District of Columbia to participate in the program, because they either were not meeting the standards themselves or were contributing to emissions in downwind States that were out of compliance. When fully implemented, CAIR was designed to cap SO_2 emissions at 2.5 million tons and NO_x emissions at 1.3 million tons in the affected States [*18*]. States could comply with the limits either by participating in a cap-and-trade system or by developing their own strategies to achieve their required reduction shares.

The annual NO_x emissions trading program developed for CAIR commenced in 2009. SO_2 emissions caps under the rule will take effect in 2010. Meanwhile, the EPA is developing a new CAIR designed to address the shortcomings identified by the court. The EPA expects to release a proposal for the replacement CAIR in May 2010 [*19*]. There is also a possibility that legislative action could be taken to develop new standards, but because the *AEO* does not anticipate future laws or regulations, *AEO2010* assumes that the long-term reduction goals of CAIR will be met through the existing cap-and-trade system specified in the current rule.

State renewable energy requirements and goals: Update through 2009

To the extent possible, *AEO2010* incorporates the impacts of State laws requiring the addition of renewable generation or capacity by utilities doing business in the States. Currently, 30 States and the District of Columbia have enforceable RPS or similar laws (Table 2). Under such standards, each State determines its own levels of generation, eligible technologies, and noncompliance penalties. *AEO2010* includes the impacts of all laws in effect as of September 2009 (with the exception of Hawaii, because NEMS provides electricity market projections for the continental United States only).

In the *AEO2010* Reference case, States generally meet their ultimate RPS targets. RPS compliance 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, which are composed of multiple States. Compliance costs in each region are tracked, and the projection for total renewable generation is checked for consistency with any State-level cost-control provisions, such as caps on renewable credit prices, limits on State compliance funding, or impacts on consumer electricity prices.

Table 2. Renewable portfolio standards in the 30 States with current mandates

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 provided to 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 dedicated 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 come 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 required an RPS target of 20 percent of sales by 2019. There is a separate requirement for solar generation (2 percent of the total), and penalty payments for compliance failure. Solar technologies receive triple credits. 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. In 2009, the rule was modified to cover sales outside a utility's home territory.
IA	In 1983, an RPS mandating105 megawatts of renewable energy capacity was adopted. A voluntary goal of 1,000 megawatts of renewable energy was adopted in 2001.
KS	In 2009, House Bill 2369 established a requirement that 20 percent of installed capacity must use renewable resources by 2020.
ME	In 2007, Public Law 403 was added to the State's RPS requirements. The original mandate of 30 percent renewable generation by 2000 was set below renewable generation at the time. The new law requires a 10-percent increase from the 2006 level of renewable capacity by 2017, and that level must be maintained in subsequent years. The years leading up to 2017 also have new capacity milestones. Generation from eligible community-owned facilities counts as 1.1 kilowatthours for every kilowatthour of actual generation.
MD	In April 2008, House Bill 375 revised the preceding RPS to contain a 20-percent target by 2022, including a 2-percent solar target. H.B. 375 also raised penalty payments for "Tier 1" compliance shortfalls to 4 cents per kilowatthour.
MA	The RPS has a goal of a 15-percent renewable share of total sales by 2020. The State also has necessary payments for compliance shortfalls. As of December 2009, consideration of the eligibility of new biomass facilities was temporarily suspended while the State studies the issue of the sustainability of biomass resources.
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 other suppliers. Also specified was the creation of a State cap-and-trade program that will assist the program's implementation. The 30-percent requirement for Excel consists of 24 percent that must be from wind, 1 percent that can be from wind or solar, and 5 percent that can be from other resources.
MO	In November 2008, Missouri voters approved Proposition C, which mandates a 2-percent renewable energy requirement in 2011, which will increase incrementally to 15 percent of generation in 2021. Bonus credits are given to renewable generation within the State.
MT	House Bill 681, approved in April 2008, 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 renewable energy credit market.
NV	The State has an escalating renewable target, established in 1997 and revised in 2005 and again in 2009 by Senate Bill 358. The most recent requirement mandates a 25-percent renewable generation share of sales by 2025. Up to one-quarter of the 25-percent share may be met through efficiency measures. There is also a minimum requirement for photovoltaic systems, which receive bonus credits.
NH	House Bill 873, passed in May 2007, legislated that 23.8 percent of electricity sales must be met by renewables in 2025. Compliance penalties vary by generation type.
NJ	In 2006, the RPS was revised to increase renewable energy targets. Renewable generation is to provide 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, passed in March 2007, directs investor-owned utilities to derive 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 25 percent of the total by 2013, from the current level of 19 percent. The program is administered and funded by the State.
NC	In 2007, 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.

(continued on page 16)

Table 2. Renewable portfolio standards in the 30 States with current mandates (continued)

State	Program mandate
OH	Senate Bill 221, passed in May 2008, requires 25 percent of electricity sales 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	Senate Bill 838 (signed into law in June 2007) required renewable targets of 25 percent by 2025 for large utilities and 5 to 10 percent by 2025 for smaller utilities. Renewable electricity on line after 1995 is considered eligible. Compliance penalty caps have not yet been determined.
PA	The Alternative Energy Portfolio Standard, signed into law in November 2004, has an18-percent requirement by 2020. Most of the qualifying generation must be renewable, but there is also a provision that allows waste coal resources to receive credits.
RI	The Renewable Energy Standard was signed into law in 2004. The program requires that 16 percent of total sales be renewable by 2019. The interim program targets escalate more rapidly in later years. If the target is not met, a generator must pay an alternative compliance penalty. State utilities must also procure 90 megawatts of new renewable capacity, including 3 megawatts of solar, by 2014.
TX	Senate Bill 20, passed in August 2005, 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	In November 2006, Washington 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.
WV	House Bill 103, passed in June 2009, established a requirement that 25 percent of sales must come from alternative energy resources by 2025. Alternative energy was defined to include various renewables, along with several different fossil energy technologies.
WI	Senate Bill 459, passed in March 2006, strengthened the State RPS with a requirement that, by 2015, each utility must generate 10 percent of its electricity from renewable resources, up from the previous requirement of 2.2 percent in 2011. The renewable share of total generation must be at least 6 percentage points above the average renewable share from 2001 to 2003.

States that have enacted new laws include the following:

Kansas. House Bill 2369 [*20*] established a capacity-based renewable electricity goal that requires 20 percent of capacity to be from renewable resources by 2020. In-State renewable capacity resources will count as 1.1 megawatts of capacity for every megawatt of nameplate capacity. Although other States, such as Texas and Iowa, have had capacity-based renewable targets before, Kansas specifies the capacity goal as a fraction of installed capacity rather than as a fixed quantity of capacity. Most of the RPS programs included in *AEO2010* are based on electricity generation; however, for modeling purposes EIA converted the capacity targets to approximate generation equivalents, assuming that wind will be the primary compliance resource.

West Virginia. In June 2009, the West Virginia legislation enacted House Bill 103 [*21*], an "alternative and renewable energy portfolio standard." The law allows certain types of coal or coal-based gases to compete to meet the same target as wind and other renewable resources. Eligible resources must meet 25 percent of electricity sales by 2025. Although other States have included nonrenewable resources in their policies, they have a separate "tier" or target schedule for the fossil resources. Because it lacks a distinct renewable energy target and presents capacity expansion requirements largely consistent with the underlying assumptions for *AEO2010*, the legislation is not specifically reflected in *AEO2010*.

States with significant modifications to existing laws include the following:

Illinois. The Illinois Commerce Commission issued additional regulations in implementing the existing Illinois RPS [*22*] with Order 09-0432 [*23*] and now applies the renewable targets to sales outside an energy service provider's territory, not just to sales by default service providers.

Maine. With the passage of LD 1075 [*24*], Maine now counts generation from eligible community-owned resources toward meeting the RPS requirements, at a rate of 1.5 kilowatthours for every kilowatthour of actual generation.

Massachusetts. On December 3, 2009, the Massachusetts Department of Energy Resources [*25*] placed a temporary hold on the consideration of certain new biomass plants to meet the State's RPS requirement. Because the action occurred after the *AEO2010* Reference case results were finalized, and because it is a temporary measure, EIA did not include it in the current projections. Currently, the Massachusetts Department of Energy Resources is studying concerns that have been raised over the sustainability of biomass resources; future consideration of biomass generation will be based on the results of that study.

Minnesota. Among other changes resulting from the passage of SF 550 [*26*], Minnesota now allows limited amounts of solar generation to be included in the wind-only generation provision applied to the State's largest utility. Whereas the prior law [*27*] required the largest utility in Minnesota to produce 25 percent of sales from wind generation and 5 percent from other eligible resources, now it may produce 24 percent from wind, 1 percent from wind or solar, and 5 percent from other eligible resources.

Nevada. In May 2009, Nevada enacted Senate Bill 358 [*28*], which increased the renewable electricity target to 25 percent of sales by 2025, of which 6 percent (1.5 percent of sales) must come from solar.

Rhode Island. In addition to its existing generation-based RPS schedule, with the enactment of H 5002 [*29*] Rhode Island will now require utilities to procure 90 megawatts of new renewable capacity, of which 3 megawatts must be solar.

Updated State air emissions regulations

Regional Greenhouse Gas Initiative

The Regional Greenhouse Gas Initiative (RGGI) is a program that includes 10 Northeast States that have agreed to curtail and reverse growth in their CO_2 emissions. The RGGI program includes all electricity generating units with a capacity of at least 25 megawatts and requires an allowance for each ton of CO_2 emitted [*30*]. The first year of mandatory compliance was in 2009.

Each participating State was provided a CO_2 budget consisting of a history-based baseline with a cushion for emissions growth, so that meeting the cap is expected to be relatively easy initially and become more stringent in subsequent years. The requirements are expected to cover 95 percent of CO_2 emissions from the region's electric power sector. Overall, the RGGI States as a whole must maintain covered emissions at a level of 188 million tons CO_2 for the next 4 years, after which a mandatory 2.5-percent annual decrease in CO_2 emissions through 2018 is expected to reduce the total for covered CO_2 emissions in the RGGI States to 10 percent below the initial calculated budget. Although each State was given its own emissions budget, allowances are auctioned at a uniform price across the entire region.

To preserve the program's integrity, several rules were agreed to by the participating States:

- Auctions are held quarterly and follow a single-round, sealed-bid format.
- Allowances are 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 have decided to auction all their allowances).
- Each emitter must buy one allowance for every ton of CO_2 emitted.
- Future allowances are made available for purchase up to 4 years before their official vintage date, as a way to reduce price volatility.
- A reserve price floor of $1.86 per allowance [*31*] in real dollars is 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 floor price is subject to change at the discretion of RGGI officials.
- Revenue from the auctions can be spent at the State's discretion, but at least 25 percent must go into a fund that benefits consumers and promotes low-carbon energy development.

Since the first auction in September 2008, there have been five subsequent RGGI auctions. At the most recent, in December 2009, 28.6 million allowances were offered and sold at a clearing price of $2.05 [*32*].

RGGI's impact on electricity markets is included in the *AEO2010* Reference case. Its impact on actual emissions, especially in the early years, is minimal because of its relatively generous emissions budget. Also, it is difficult to capture the nuances of initiatives that cover only single States or groups of States that do not correspond to the regions used in NEMS. Therefore, EIA estimated generation for the Mid-Atlantic region and capped emissions from those facilities. Pennsylvania's emissions were not restricted, because Pennsylvania is an observing member and is not participating in the cap-and-trade program or subject to any mandatory emission reductions.

Western Climate Initiative

The Western Climate Initiative (WCI) [*33*] is a separate regional GHG emissions reduction program. Participants include seven U.S. States (Arizona, California, Montana, New Mexico, Oregon, Utah, and Washington) and four Canadian Provinces (British

Columbia, Manitoba, Ontario, and Quebec), as well as additional observer States and Provinces in the United States, Canada, and Mexico. Unlike RGGI, the WCI and California regulations are not included in the *AEO2010* Reference case, because their rules still are subject to change.

The initiative seeks to reduce GHG to levels 15 percent below 2005 emissions by 2020. Although the original plan was to achieve the reductions through an allowance cap-and-trade program, the current economic environment and changing political landscape have led some of the States to reevaluate their participation. Each State must provide legislative authority for the cap-and-trade system, and currently only California has the required authority in place. Consequently, the WCI has recently formed a complementary policy committee that will examine moving beyond cap and trade to explore issues such as tightening building codes, instituting appliance efficiency standards, and adopting RPS programs.

The WCI cap-and-trade structure is similar to RGGI but with some important differences. For example, the first phase of the program (2012-2015) would not cover emissions produced by the combustion of fossil fuels from smaller facilities or mobile sources, but all fuels would be covered by 2015, including fuels used in the residential, commercial, industrial, and transportation sectors. All fuels will be regulated at the point where they enter commerce, which generally is at a fuel distributor. This may vary, however, and the exact point will be determined before 2015.

The 2015 fuel cap is an expansion in scope over the first phase, which applies only to facilities emitting more than 25,000 CO_2-equivalent metric tons per year. Although the second phase covers fuels at the distributor level, the first phase regulates the larger, stationary facilities at the emissions source. The WCI recommends that States begin mandatory emissions monitoring this year, so that reporting can begin in 2011. As of January 2010, Arizona and Montana had not committed to the WCI reporting goals.

Another distinction between RGGI and WCI is that the latter would cover emissions of nitrous oxide, methane, hydrofluorocarbons, perfluorocarbons, and sulfur hexafluoride in addition to CO_2. Emissions of the additional gases would be measured in terms of their CO_2-equivalent global warming potentials, and allowances would be issued accordingly. WCI documents estimate that 90 percent of the region's GHG emissions would be subject to regulation after combustion fuels are included in 2015.

As noted above, California's Assembly Bill (A.B.) 32 gives the CARB authority to regulate GHG emissions and reduce them to 1990 levels by 2020. The Board recently released its draft regulations, which were open to comment until January 2010 [*34*]. A public report is expected to be issued in spring 2010, and a final version is due to be released in fall 2010. The State will use a cap-and-trade program to cover 85 percent of its GHG emissions— equivalent to covering the 600 largest stationary emissions sources as well as suppliers of residential, commercial, industrial, and transportation fuels. Imported power also is subject to the regulations.

Currently, three compliance periods are proposed: 2012-2014, 2015-2017, and 2018-2020. The first period will cover electricity generation and industrial sources emitting more than 25,000 metric tons CO_2 equivalent per year. The second period will begin a phase-in of smaller industrial sources and fuels. The third period will have a lower GHG ceiling that will extend beyond 2020. It is important to note, however, that this is tentative, and the compliance period may be shortened to one year rather than the current three. As of January 2010, the GHG caps for each period had not been met.

Midwestern Greenhouse Gas Reduction Accord

The Midwestern Greenhouse Gas Reduction Accord [*35*] is another regional initiative that seeks to curtail emissions. Six States (Illinois, Iowa, Kansas, Michigan, Minnesota, and Wisconsin) and one Canadian province (Manitoba) are members, and there are four additional observer States. Its advisory group released a draft of final recommendations in June 2009 [*36*]. The program is similar in structure to the WCI, and it seeks a 20-percent reduction from 2005 GHG emission levels by 2020 and an 80-percent reduction by 2050.

Although its final recommendations strongly urge Federal action, the committee has stated that it will proceed with a regional cap-and-trade system in the absence of Federal legislation. Finalized rules for the Accord have been delayed and are expected to be released sometime in 2010. The draft rules for the Midwestern Greenhouse Gas Reduction Accord are detailed [*37*], but because they are preliminary they are not included in *AEO2010*.

Endnotes for Legislation and Regulations

1. For complete text of the ARRA, see web site http://frwebgate.access.gpo.gov/cgi-bin/getdoc.cgi?dbname=111_cong_public_laws&docid=f:publ005.111.
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3. 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.
4. U.S. Court of Appeals for the District of Columbia Circuit, No. 05-1244, web site www.epa.gov/airmarkets/progsregs/cair/docs/CAIRRemandOrder.pdf.
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7. Certain types of biomass, municipal waste, and hydroelectric generation are eligible for only one-half of the 2.1-cent credit. The ITC alternative is not limited in value for those technologies.
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14. California Air Resources Board, *Proposed Regulation to Implement the Low Carbon Fuel Standard*, Volume I (March 5, 2009), web site www.arb.ca.gov/fuels/lcfs/030409lcfs_isor_vol1.pdf.
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Issues in Focus

Introduction

Each year, the Issues in Focus section of the *AEO* provides an in-depth discussion on topics of special interest, including significant changes in assumptions and recent developments in technologies for energy production, supply, and consumption. The first section compares the results of two cases that adopt different assumptions about the future course of existing energy policies. One case assumes the elimination of sunset provisions in existing energy policies. The other case assumes the extension of a selected group of existing policies—CAFE standards, appliance standards, and PTCs—in addition to the elimination of sunset provisions.

Other sections include a discussion of end-use energy efficiency trends in *AEO2010*; an analysis of the impact of incentives on the use of natural gas in heavy freight trucks; factors affecting the relationship between crude oil and natural gas prices; the sensitivity of the projection results to variations in assumptions about the availability of U.S. shale gas resources; the implications of retiring nuclear plants after 60 years of operation; and issues related to accounting for CO_2 emissions from biomass energy combustion.

The topics explored in this section represent current, emerging issues in energy markets; but many of the topics discussed in *AEO*s published in recent years also remain relevant today. Table 3 provides a list of titles from the 2009, 2008, and 2007 *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.

No Sunset and Extended Policies cases

Background

The *AEO2010* Reference case is best described as a "current laws and regulations" case, because it generally assumes that existing laws and fully promulgated regulations will remain unchanged throughout the projection period, unless the legislation establishing them specifically calls for them to end or change. The Reference case often serves as a starting point for the analysis of proposed legislative or regulatory changes, a task that would be difficult if the Reference case included "projected" legislative or regulatory changes.

As might be expected, it is sometimes difficult to draw a line between what should be included or excluded from the Reference case. Areas of particular uncertainty include:

- Laws or regulations that have a history of being extended beyond their legislated sunset dates. Examples include the various tax credits for renewable fuels and technologies, which have been extended with or without modifications several times since their initial implementation.
- Laws or regulations that call for the periodic updating of initial specifications. Examples include appliance efficiency standards issued by the U.S. DOE and CAFE standards for vehicles issued by NHTSA.
- Laws or regulations that allow or require the appropriate regulatory agency to issue new or revised regulations under certain conditions.

Table 3. Key analyses from "Issues in Focus" in recent *AEO*s

AEO2009	*AEO2008*	*AEO2007*
Economics of Plug-In Hybrid Electric Vehicles	Impacts of Uncertainty in Energy Project Costs	Impacts of Rising Construction and Equipment Costs on Energy Industries
Impact of Limitations on Access to Oil and Natural Gas Resources in the Federal Outer Continental Shelf	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
Expectations for Oil Shale Production	Trends in Heating and Cooling Degree-Days: Implications for Energy Demand	Miscellaneous Electricity Services in the Buildings Sector
Bringing Alaska North Slope Natural Gas to Market	Liquefied Natural Gas: Global Challenges	Industrial Sector Energy Demand: Revisions for Non-Energy-Intensive Manufacturing
Natural Gas and Crude Oil Prices in *AEO2009*	World Oil Prices and Production Trends in *AEO2008*	World Oil Prices in *AEO2007*
Electricity Plant Cost Uncertainties		Biofuels in the U.S. Transportation Sector
Greenhouse Gas Concerns and Power Sector Planning		Loan Guarantees and the Economies of Electricity Generating Technologies
Tax Credits and Renewable Generation		Alaska Natural Gas Pipeline Developments
		Coal Transportation Issues

Examples include the numerous provisions of the CAA that require the EPA to issue or revise regulations if they find that some type of emission is harmful to the public health, or that standards are not being met.

To provide some insight into the sensitivity of results to different characterizations of "current laws and regulations," two alternative cases are discussed in this section. No attempt is made to cover the full range of possible uncertainties in these areas, and readers should not view the cases discussed as EIA projections of how laws or regulations might or should be changed.

Analysis cases

The two cases prepared—the No Sunset case and Extended Policies case—incorporate all the assumptions from the *AEO2010* Reference case, except as identified below. Changes from the Reference case assumptions in these cases include the following.

No Sunset case

- Extension of renewable PTCs, ITCs, and tax credits for energy-efficient equipment in the buildings sector through 2035, including:
  - The PTC of 2.1 cents per kilowatthour or the 30-percent ITC available for wind, geothermal, biomass, hydroelectric, and landfill gas resources, currently set to expire at the end of 2012 for wind and 2013 for the other eligible resources.
  - For solar power investment, a 30-percent ITC that is scheduled to revert to a 10-percent credit in 2016 is, instead, assumed to be extended indefinitely at 30 percent.
  - In the buildings sector, tax credits for the purchase of energy-efficient equipment, including PV in new houses, are assumed to be extended indefinitely, as opposed to ending in 2010 or 2016 as prescribed by current law. The business ITC for commercial-sector generation technologies and geothermal heat pumps are assumed to be extended indefinitely, as opposed to expiring in 2016; and the business ITC for solar systems is assumed to remain at 30 percent instead of reverting to 10 percent.
  - In the industrial sector, the ITC for CHP that ends in 2016 in the *AEO2010* Reference case is assumed to be extended through 2035.
- Extension of the $0.45 per gallon blender's tax credit for ethanol through 2035; it is set to expire at the end of 2010.
- Continued implementation of the RFS after the 2022 date currently specified in EISA2007 until the renewable fuels target of 36 billion gallons is met. After the 36 billion gallon level is met, the mandate is assumed to continue increasing production in proportion to growth in overall transportation fuel use.
- Extension of the $1.00 per gallon biodiesel excise tax credit through 2035; rather than expiring on December 31, 2009.
- Extension of the $0.54 per gallon tariff on imported ethanol through 2035; it is set to expire at the end of 2010.
- Extension of the $1.01 per gallon cellulosic biofuels PTC through 2035; rather than expiring at the end of 2012.

Extended Policies case

With the exception of the blender's and other biofuel tax credits, the Extended Policies case adopts the same assumptions as in the No Sunset case, plus the following:

- Federal appliance efficiency standards are updated at particular intervals consistent with the provisions in the existing law, with the levels determined by the consumer impact tests under DOE testing procedures, or under Federal Energy Management Program (FEMP) purchasing guidelines.

  The efficiency levels chosen for the updated residential standards are based on the technology menu from the *AEO2010* Reference case, and whether or not the efficiency level passed the consumer impact test prescribed in DOE's standards-setting process. The efficiency levels chosen for the updated commercial equipment standards are based on the technology menu from the *AEO2010* Reference case and FEMP-designated purchasing specifications for Federal agencies.
- The implementation of rules proposed by NHTSA and the EPA for national tailpipe CO_2-equivalent emission and fuel economy standards for LDVs, including both passenger cars and light-duty trucks, has been harmonized.

  In the *AEO2010* Reference case, which applies the NHTSA and EPA rules, the new CAFE standards lead to an increase in fleet-wide LDV standards from 27.1 mpg in MY 2011 to 34.0 mpg in MY 2016, based on projected sales of vehicles by type and footprint. As required by EISA2007, the fuel economy standards increase to 35 mpg in 2020. The Extended Policies case assumes further increases in the standards, so that the minimum fuel economy standard for LDVs increases to 45.6 mpg in 2035. In actual practice, the new CAFE would need to meet a test of economic practicality.

- The extension of the blender's and all biofuels excise tax credits through 2035 adopted in the No Sunset case are *not* included in the Extended Policies case. The RFS enacted in EISA2007 is an alternative instrument for stimulating demand for biofuels, it already is represented in the *AEO2010* Reference case, and it tends to be the binding driver on biofuels rather than the tax credits.

Analysis results

The assumption changes made in the Extended Policies case generally lead to lower overall energy consumption, increased use of renewable fuels, particularly for electricity generation, and reduced energy-related GHG emissions. While this case shows lower energy prices because the impacts of the tax credits and end-use efficiency standards lead to lower energy demand and reduce the cost of renewable fuels, consumers spend more on appliances that are more efficient in order to comply with the tighter appliance standards, and the Government receives lower tax revenues as consumers and businesses take advantage of the tax credits.

Energy consumption

Total energy consumption in the No Sunset case is close to the level in the Reference case (Figure 7). Lower energy prices in the No Sunset case lead to slightly higher energy consumption, but the difference never reaches as much as 1 percent in any year of the projections.

Total energy consumption in the Extended Policies case, which assumes the issuance of more stringent efficiency standards for end-use appliances and LDVs in the future, is lower than in the Reference case. In 2035, total energy consumption in the Extended Policies case is nearly 3 percent below the projection in the Reference case. As an example of individual end uses, the assumed future standard for residential electric water heating, which requires installation of heat pumps starting in 2013, has the potential to reduce their electricity use by 60 percent from the Reference case level in 2035. Overall, delivered energy use in the buildings sector in 2035 is 5 percent lower in the Extended Policies case.

The impact on LDV energy use in the transportation sector in the Extended Policies case is similar. In 2035, total LDV energy use in the Extended Policies case is nearly 6 percent lower than in the Reference case (Figure 8) and less than 0.5 percent above the 2007 level. Relative to the *AEO2010* Reference case, the efficiency standard for new LDVs in 2035 is 10 mpg higher in the Extended Policies case—46 mpg versus 36 mpg (Figure 9); however, higher fuel prices in the Reference case improve the cost competitiveness of advanced technologies, leading to improvements in fuel economy that are above the minimum requirements (Figure 10). As a result, the average fuel economy of new LDVs in the Reference case increases to 40 mpg in 2035 [Reference (achieved)], which is 4 mpg above the required minimum. In the Extended Policies case, the fuel economy standards are binding [Extended Policies (achieved)], because increases in fuel economy above the standards

Figure 7. Total energy consumption in three cases, 2005-2035 (quadrillion Btu)

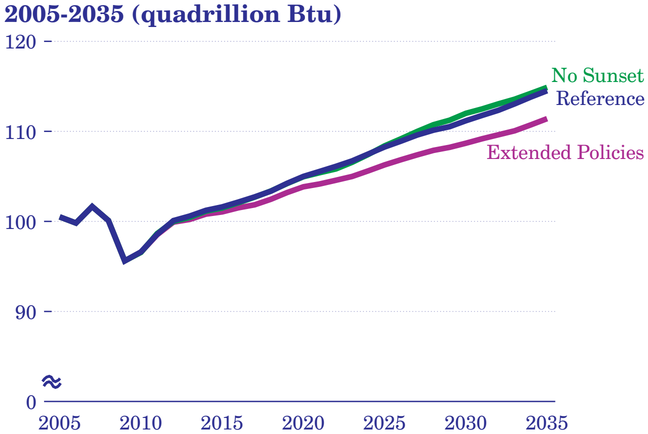
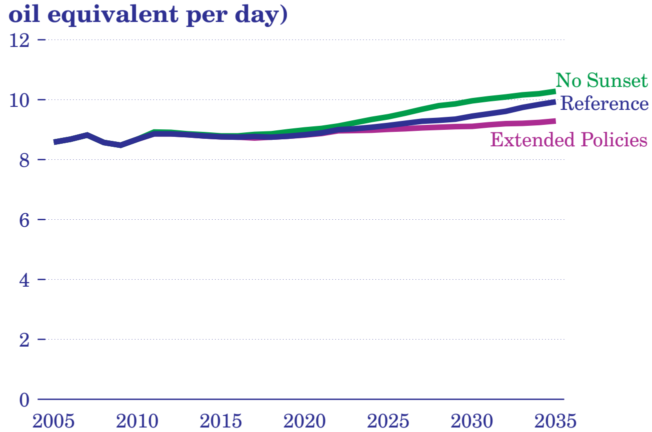


Figure 8. Light-duty vehicle energy consumption in three cases, 2005-2035 (million barrels oil equivalent per day)



require advanced technologies that are not cost-effective given the projected fuel prices.

Renewable electricity generation

The extension of tax credits for renewables through 2035 would lead to more rapid growth in renewable generation than projected in the Reference case, particularly over the longer run. When the renewable tax credits are extended without extending energy efficiency standards, as is assumed in the No Sunset case, there is significant growth in renewable generation throughout the projection period relative to the Reference case projection (Figure 11). Extending both renewable tax credits *and* energy efficiency standards results in more modest growth in renewable generation, because renewable generation in the near term is the primary source of new generation to meet load growth, and enhanced energy efficiency standards tend to reduce overall electricity consumption and the need for new generation resources.

Figure 9. New light-duty vehicle fuel efficiency standards in two cases, 2005-2035 (miles per gallon)

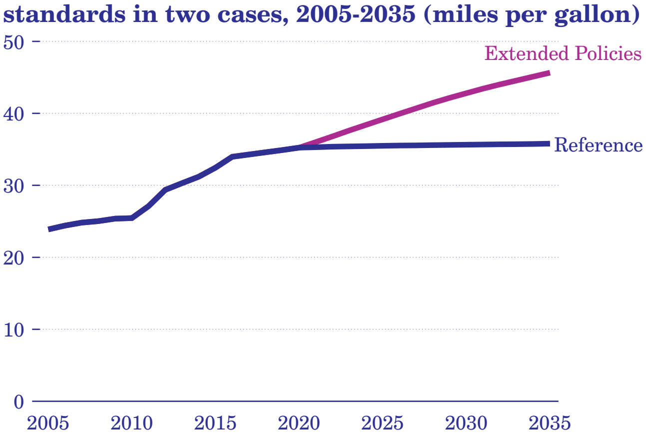
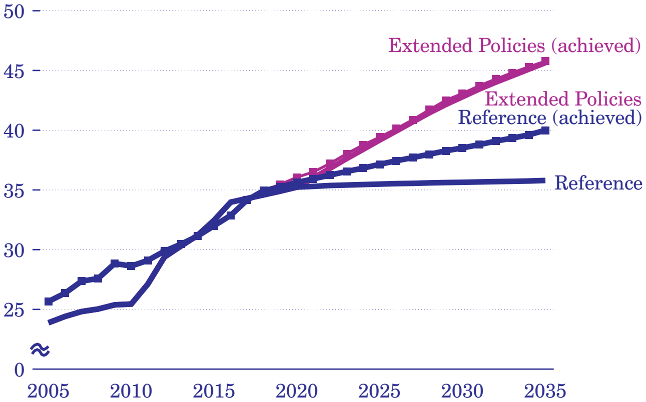


Figure 10. New light-duty vehicle fuel efficiency standards and fuel efficiency achieved in two cases, 2005-2035 (miles per gallon)

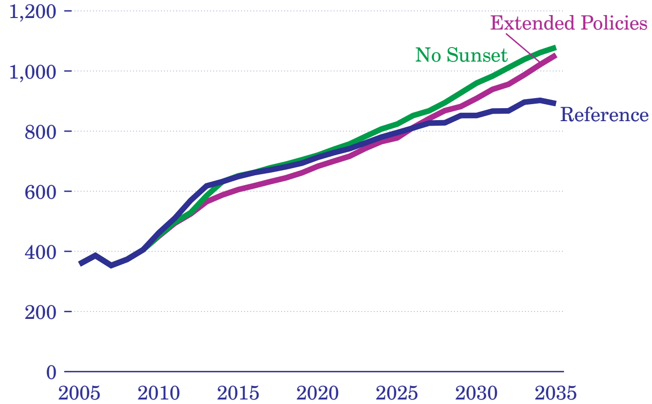


In the Reference case, growth in renewable generation accounts for 45 percent of total generation growth from 2008 to 2035. In the No Sunset and Extended Policies cases, growth in renewable generation accounts for 61 to 65 percent of total generation growth. In 2035, the share of total electricity sales accounted for by nonhydroelectric renewables is 13 percent in the Reference case, as compared with 17 percent in the No Sunset and Extended Policies cases.

In all three cases, the most rapid growth in renewable capacity occurs in the near term, then slows through 2020, before picking up again. Before 2015, ample supplies of renewable energy in relatively favorable resource areas (windy lands, accessible geothermal sites, and low-cost biomass), combined with the Federal incentives, make renewable generation competitive with conventional sources. If the rapid growth in renewables is dampened because of the economic downturn, more natural gas generation would be expected. With slow growth in electricity demand and the addition of capacity stimulated by renewable incentives before 2015, little new capacity is needed between 2015 and 2020. In addition, in many regions, most attractive low-cost renewable resources already have been exploited, leaving less-favorable sites that may require significant investment in transmission as well as other additional infrastructure costs. New sources of renewable generation also appear on the market as a result of cogeneration at biorefineries built primarily to produce renewable liquid fuels to meet the Federal RFS, where combustion of waste products to produce electricity is an economically attractive option.

After 2020, renewable generation in the No Sunset and Extended Policies cases increases more rapidly than in the Reference case, and as a result

Figure 11. Renewable electricity generation in three cases, 2005-2035 (billion kilowatthours)



generation from fossil fuels—particularly natural gas—is reduced from the levels projected in the Reference case (Figure 12). In 2035, electricity generation from natural gas in the No Sunset and Extended Policies cases is 13 percent and 16 percent lower, respectively, than in the Reference case.

Greenhouse gas emissions

In the No Sunset and Extended Policies cases, the combination of lower overall energy demand and greater use of renewable fuels leads to lower levels of energy-related CO_2 emissions than projected in the Reference case. The difference grows over time, to 146 million metric tons (2 percent) in the No Sunset case and 200 million metric tons (3 percent) in the Extended Policies case in 2035 (Figure 13). From 2012 to 2035, energy-related CO_2 emissions are reduced by a cumulative total of more than 1.9 billion metric tons in the Extended Policies case relative to the Reference case.

Energy prices and tax credit payments

With lower levels of overall energy use and more consumption of renewable fuels in the No Sunset and Extended Policies cases, energy prices are lower than projected in the Reference case. In 2035, natural gas wellhead prices are $0.56 per thousand cubic feet (7 percent) and $0.70 per thousand cubic feet (9 percent) lower in the No Sunset and Extended Policies cases, respectively, than in the Reference case (Figure 14), and electricity prices are 5 percent and 6 percent lower than projected in the Reference case (Figure 15).

The reductions in energy consumption and CO_2 emissions in the Extended Policies case require additional equipment costs to consumers and revenue reductions for the Government. From 2010 to 2035, residential and commercial consumers spend an additional $16 billion (real 2008 dollars) per year on average for newly purchased end-use equipment, distributed generation systems, and residential shell

Figure 12. Electricity generation from natural gas in three cases, 2005-2035 (billion kilowatthours)

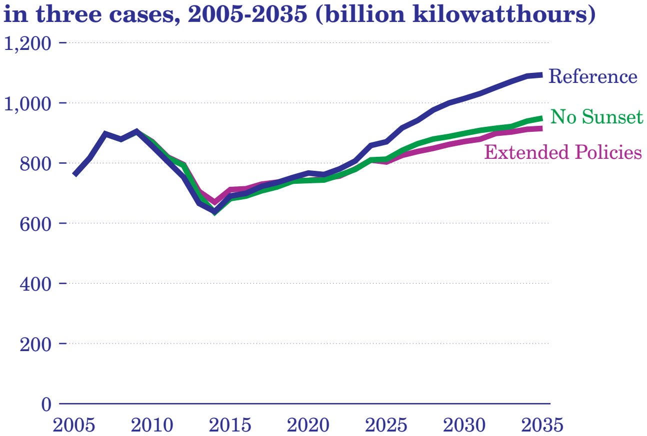


Figure 13. Energy-related carbon dioxide emissions in three cases, 2005-2035 (million metric tons)

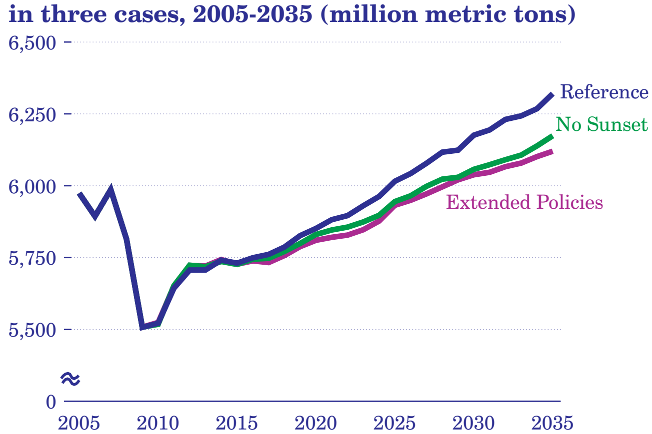


Figure 14. Natural gas wellhead prices in three cases, 2005-2035 (2008 dollars per thousand cubic feet)

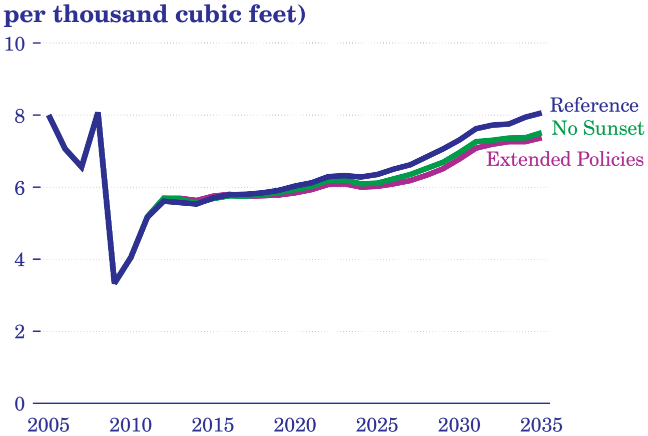
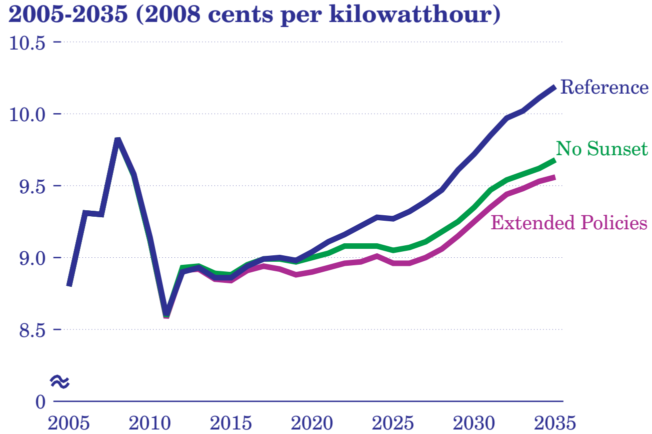


Figure 15. Average electricity prices in three cases, 2005-2035 (2008 cents per kilowatthour)



improvements in the Extended Policies case than in the Reference case.

Tax credits paid to consumers in the buildings sector in the Extended Policies case average $10.5 billion more per year than in the Reference case, reaching a cumulative total of $300 billion in revenue reductions to the Government over the period from 2010 to 2035. In comparison, cumulative revenue reductions as a result of tax credits in the buildings sector total $27 billion over the same period in the Reference case. The largest response to Federal PTC incentives for new central-station renewable generation is seen in the No Sunset case, with extension of the PTC resulting in cumulative reductions in Government tax revenues that total approximately $45 billion from 2010 to 2035, as compared with $24 billion in the Reference case. Additional reductions in Government tax revenue in the No Sunset case result from extension of the blenders tax credit, the biodiesel blenders tax credit, and the cellulosic biofuels PTC, with cumulative total tax revenue reductions from 2010 to 2035 of $156 billion, $32 billion, and $168 billion (all in 2008 dollars), respectively, compared to the Reference case.

World oil prices and production trends in *AEO2010*

In *AEO2010*, the price of light, low-sulfur (or "sweet") crude oil delivered at Cushing, Oklahoma, is tracked to represent movements in world oil prices. EIA makes projections of future supply and demand for "total liquids," which includes conventional petroleum liquids—such as conventional crude oil, natural gas plant liquids, and refinery gain—in addition to unconventional liquids, which include biofuels, bitumen, coal-to-liquids (CTL), gas-to-liquids (GTL), extra-heavy oils, and shale oil.

World oil prices can be influenced by a multitude of factors. Some tend to be short term, such as movements in exchange rates, financial markets, and weather, and some are longer term, such as expectations concerning future demand and production decisions by the Organization of the Petroleum Exporting Countries (OPEC). In 2009, the interaction of market factors led prompt month contracts (contracts for the nearest traded month) for crude oil to rise relatively steadily from a January average of $41.68 per barrel to a December average of $74.47 per barrel [*38*].

Changes in the world oil market over the course of 2009 served to highlight the myriad factors driving future liquids demand and supply and how a change in these factors can reverberate through the world liquids market. Over the long term, world oil prices in EIA's outlook are determined by four broad factors: non-OPEC conventional liquids supply, OPEC investment and production decisions, unconventional liquids supply, and world liquids demand. Uncertainty in long-term projections of world oil prices can be explained largely by uncertainty about one or more of these four broad factors.

Recent market trends

In 2009, world oil prices were especially sensitive to demand expectations, with producers, consumers, and traders constantly looking for any indication of a possible recovery in the world's economy and a likely corresponding increase in oil demand.

On the supply side, OPEC demonstrated greater dedication to supporting prices in 2009 than it had in other recent periods where it adopted restraints on production. From February to June 2008, OPEC maintained 70 percent or greater compliance as measured by the actual aggregate production cuts achieved by quota-restricted members as a percentage of the group's agreed-upon production cut, before falling to average levels of just above 60 percent after September [*39*]. The above-average compliance increased the group's spare capacity to roughly 5 million barrels per day in December 2009, and helped boost prices to a range of $70 to $80 per barrel [*40*].

Since June 2009, Iraq has held two rounds of bidding for development of its oil resources. The sum of the targeted production increase from the awarded fields is about 9.5 million barrels per day, or almost four times the country's current production. Although most industry analysts do not expect Iraq to achieve those production targets in full, the likely increase may cause changes in OPEC quota allocations and long-term production decisions.

There were also significant developments for non-OPEC supply in 2009, some with potentially long-lasting implications. Although oil prices rose throughout 2009, many of the projects delayed during the price slump that started in August 2008 have not yet been revived. The time required for project development creates a lag between investment decisions and increased oil deliveries, indicating that medium-term supply growth may be constrained if delayed projects are not restarted in the short term.

A related trend, which began in 2008 and continued in 2009, was a decline in factor input costs—i.e., the costs of the materials, labor, and equipment necessary to develop liquids projects. The decline in construction material costs and rig rates may have encouraged the delay of some projects, as investors played a wait-and-see game in order to secure contracts at the lowest possible cost. That trend appears to have bottomed out at the end of 2009, however, after producing only a slight overall reduction in costs [*41*]. Before the recent reduction in production costs, an industry research group estimated that costs had approximately doubled since 2000 [*42*].

Severe problems in the global credit market that began in 2008 and continued through 2009 have made it difficult to finance some exploration and production (E&P) projects. The full effect of limits on credit availability for oil supply projects will not be realized for some time, as the projects stalled due to a lack of financing, particularly exploration projects, would not have brought supply to the market for several years. In addition to its impact on individual E&P projects, the recent credit crisis may also have led to an overall and possibly lasting change in risk tolerance on the part of both lenders and investors. Still, while credit terms were being tightened and financial risk was being trimmed, ongoing exploration efforts in Africa resulted in a wave of discoveries and new hope for unexplored and under-explored non-OPEC resources.

Long-term prospects

Developments in 2008 and 2009 have demonstrated the range of the uncertainties that underlie the four broad factors underlying long-term world oil prices, as described above. It remains unclear how the world's economy and the demand for liquids will recover, what non-OPEC resources will be brought to market, what production targets OPEC will set or meet, and whether or when individual unconventional liquids projects will come online. The price path assumptions in *AEO2010* encompass a broad range of possible production levels and world oil price paths, with a range of $160 per barrel (in real terms) between the High Oil Price and Low Oil Price cases in 2035 (Figure 16). Consideration of Low and High Oil Price cases allows EIA and others to analyze a variety of future oil and energy market conditions in comparison with the Reference case.

Reference case oil prices

The global oil market projections in the *AEO2010* Reference case are based on the assumption that current practices, politics, and levels of access will continue in the near to mid-term, whereas long-term developments will be determined largely by economics. The Reference case assumes that the world economy— and liquids demand—experience significant recovery in 2010, with total liquids consumption returning to the 2008 level of just under 86 million barrels per day.

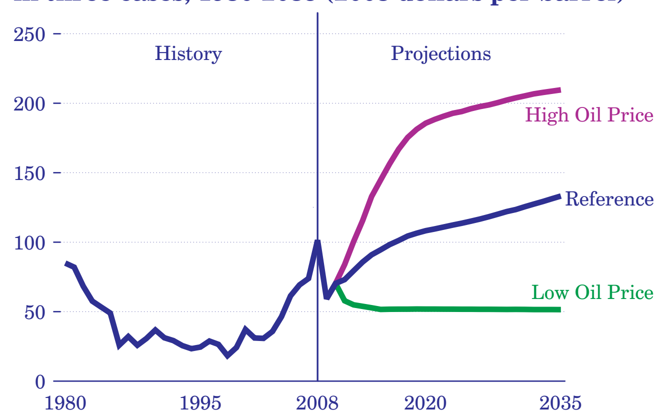
Satisfying the growing world demand for liquids in the next decade will require accessing higher cost supplies, particularly from non-OPEC producers. In the Reference case, the higher cost of non-OPEC supply supports average annual increases in real world oil prices of approximately 0.7 percent from 2008 to 2020 and 1.4 percent from 2020 to 2035. Oil prices, in real terms, rebound following the global recession, to $95 per barrel in 2015 and $133 per barrel in 2035 (real 2008 dollars). Although increases in OPEC production will meet a portion of the growing world demand, the Reference case assumes that OPEC's limits on production growth will maintain its share of total world liquids supply at approximately 40 percent, where it has roughly been over the past 15 years.

Growth in non-OPEC production will come primarily from high-cost conventional projects in regions with unstable fiscal or political regimes and from relatively expensive unconventional liquids projects. The return to higher price levels in the Reference case results from limited access to prospective areas for foreign investors, less attractive fiscal terms, and higher exploration and production costs than have been seen in the past.

Low Oil Price case

The *AEO2010* Low Oil Price case assumes that greater competition and international cooperation will guide the development of political and fiscal

Figure 16. Average annual world oil prices in three cases, 1980-2035 (2008 dollars per barrel)



regimes in both consuming and producing nations, facilitating coordination and cooperation among them. Non-OPEC producing countries are assumed to develop fiscal policies and investment regimes that encourage private-sector participation in the development of their domestic resources; and OPEC is assumed to increase its production levels, providing 50 percent of the world's liquids supply by 2035. The availability of low-cost resources in both non-OPEC and OPEC countries allows for prices to stabilize at relatively low levels, $51 per barrel in real 2008 dollars, thereby reducing the incentive for consuming nations to invest in unconventional liquids production as heavily as they do in the Reference case.

High Oil Price case

The *AEO2010* High Oil Price case assumes not only a rebound in world oil prices with the return of world economic growth, but also a continued rapid escalation in prices as a result of long-term restrictions on conventional liquids production. The restrictions result from both political decisions and resource characteristics: the major OPEC and non-OPEC producing countries use quotas, fiscal regimes, and varying degrees of nationalization to further increase revenues from oil production, and the consuming countries turn to domestic production of high-cost unconventional liquids to satisfy demand. As a result, in the High Oil Price case, world oil prices rise throughout the projection period, to $210 per barrel in 2035. Liquids demand is dampened by the high prices, but is overshadowed by the severity of limitations on access to and availability of lower cost conventional resources. OPEC's share of production falls to 35 percent.

Components of liquid fuels supply

In the *AEO2010* Reference case, total world liquid fuels consumption in 2035 is 112 million barrels per day, or 26 million barrels per day higher than in 2008, with production increases from OPEC and non-OPEC conventional sources totaling 15.5 million barrels per day. As a result, the conventional liquids share of world liquids supply drops from 95 percent in 2008 to 87 percent in 2035.

Production of unconventional crude oils in the *AEO2010* Reference case is 4.0 million barrels per day higher in 2035 than in 2008 and represents 5.6 percent of global liquid fuels supply in 2035. Production increases from Venezuela's Orinoco belt and Canada's oil sands are limited by access restrictions in Venezuela and environmental concerns in Canada. The relatively high world oil prices in the Reference case encourage U.S. production of oil shale, with volumes reaching 0.4 million barrels per day in 2035. Relatively high prices also encourage growth in global CTL, GTL, and biofuel production, from a combined total of 1.8 million barrels per day in 2008 to 8.4 million barrels per day in 2035, or 8 percent of total liquids supplied.

In the *AEO2010* Low Oil Price case, oil prices are on average more than 50 percent lower than in the Reference case from 2015 to 2035. In this case, conventional crude oil accounts for the largest share of total liquids production in any of the three price cases in 2035, at about 90 percent. Production of conventional crude oil totals 100.5 million barrels per day in 2035, higher than the total for all conventional liquids in the Reference case. Total conventional liquids production reaches 114.8 million barrels per day, and total liquids production reaches 127 million barrels per day, in the Low Oil Price case in 2035.

Despite their generally higher costs, production of unconventional crude oils is also higher in the Low Oil Price case than in the Reference case, as a result of changes in economic access to resources. In the Low Oil Price case, Venezuela's production of extra-heavy oil in 2035 increases from the Reference case projection of 1.3 million barrels per day to 3.4 million barrels per day—a 160-percent increase that more than compensates for lower production of Canada's oil sands (0.6 million barrels per day in 2035) due to reduced profitability. Total production of unconventional crude oil in the Low Oil Price case is 1.0 million barrels per day higher in 2035 than projected in the Reference case. Production of other unconventional liquids (CTL, GTL, and biofuels) in 2035, primarily in the United States, China, and Brazil, is 3.2 million barrels per day lower than projected in the Reference case, again due to reduced profitability.

In the High Oil Price case, oil prices from 2015 to 2035 are on average 66 percent higher than in the Reference case. The higher prices are caused by restrictions on economic access to non-OPEC conventional resources in countries such as Russia, Kazakhstan, and Brazil, combined with reductions in OPEC production. Conventional liquids production in the High Oil Price case totals 71.8 million barrels per day in 2035, 9.8 million barrels per day lower than the 2008 total; total liquids production reaches only 91 million barrels per day in 2035.

Access restrictions also limit the production of Venezuela's extra-heavy oil from the Orinoco belt, which totals 0.8 million barrels per day in 2035, as compared with 1.3 million barrels per day in the Reference case. Higher world oil prices support increased production from Canada's oil sands, which totals 5.5 million barrels per day in 2035, as compared with 4.5 million barrels per day in the Reference case. Production of shale oil, predominantly in the United States, does not change appreciably from the Reference case level in the High Oil Price case, because the projects are economically viable in the Reference case, and even a 66-percent increase in prices does not stimulate additional production growth. With the increase in oil sands production outweighing the decrease in extra-heavy oil production through 2035, production of unconventional crude oil from all sources is higher in the High Oil Price case than in the Reference case.

Production of liquids from other unconventional sources, including CTL, GTL, and biofuels, is almost 50 percent (3.9 million barrels per day) higher in the High Oil Price case than in the Reference case in 2035. The increase results primarily from higher CTL production in China (approximately 1.3 million barrels per day above the Reference case projection in 2035) and higher biofuels production in the United States (0.9 million barrels per day above the Reference case in 2035). U.S. GTL production in the High Oil Price case is notably different from the Reference case projection, with production beginning in 2017 and reaching 0.5 million barrels per day in 2035.

Energy intensity trends in *AEO2010*

Energy intensity—energy consumption per dollar of real GDP—indicates how much energy a country uses to produce its goods and services. From the early 1950s to the early 1970s, U.S. total primary energy consumption and real GDP increased at nearly the same annual rate (Figure 17). During that period, real oil prices remained virtually flat. In contrast, from the mid-1970s to 2008, the relationship between energy consumption and real GDP growth changed, with primary energy consumption growing at less than one-third the previous average rate and real GDP growth continuing to grow at its historical rate. The decoupling of real GDP growth from energy consumption growth led to a decline in energy intensity that averaged 2.8 percent per year from 1973 to 2008. In the *AEO2010* Reference case, energy intensity continues to decline, at an average annual rate of 1.9 percent from 2008 to 2035.

Definitions and classifications

Energy efficiency is defined as the ratio of the amount of energy services provided to the amount of energy consumed [*43*]. Familiar examples of energy services are the heat supplied by a furnace and the light output of a lamp.

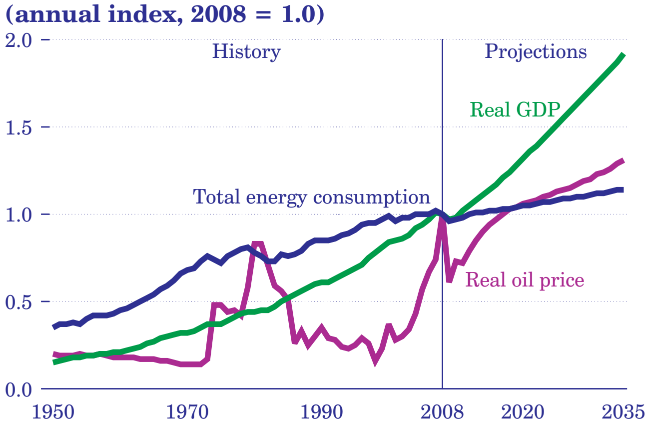
Energy conservation is defined as the lowering of energy consumption by reducing energy services. For example, lowering a thermostat's setting during the heating season is classified as energy conservation, because less heating is provided. Because the ratio of energy services to energy consumption is unchanged, energy efficiency does not change in this example.

As indicated above, *energy intensity* is defined as energy consumption per dollar of real GDP. Any change in energy intensity that does not result from a change in efficiency is referred to as a *structural change* [*44*]. Examples of structural change include energy conservation, a change in the mix of economic activity among the sectors of the economy, a change in the mix of activities within a sector, and a geographical change in population density. Energy use is affected in these examples of structural change, but not because of changes in energy efficiency.

CO_2 emissions associated with energy production and consumption are a growing concern. *Carbon intensity* is the ratio of CO_2 emissions to real GDP. The type of fuel used to provide energy services—or in the case of electricity, the fuel used to generate it—affects carbon intensity.

As defined here, efficiency and intensity are inversely related: increases in energy efficiency reduce energy intensity. To facilitate comparisons among them, the

Figure 17. Trends in U.S. oil prices, energy consumption, and economic output, 1950-2035 (annual index, 2008 = 1.0)

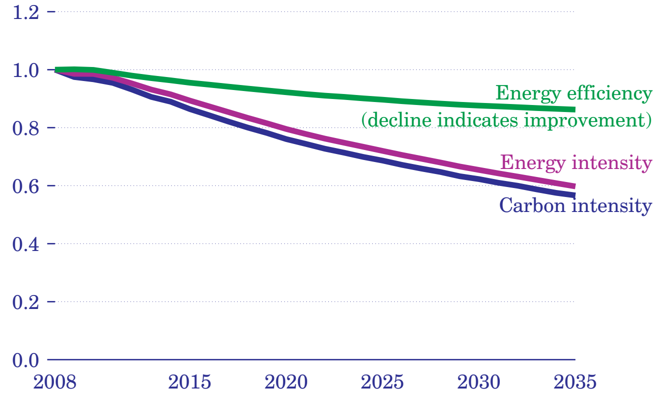


efficiency index discussed below is calculated as the inverse of the usual efficiency concept: energy consumption per unit of service demand. In this way, both improvements in efficiency and improvements in intensity are shown as decreases.

Results for the Reference case

Because the available data are limited, it is difficult to determine the amount of historical decoupling of energy consumption growth from real GDP growth that was attributable to improvements in energy efficiency [*45*]. With the wealth of technology detail on energy-using equipment in NEMS, efficiency can be characterized readily [*46*]. Figure 18 compares indexes of the Reference case projections for energy efficiency, energy intensity, and carbon intensity. The average rate of decline in the index for energy intensity from 2008 to 2035 is almost quadruple the rate of decline in the index for energy efficiency, reflecting the dominant role of structural change. The

Figure 18. Projected changes in indexes of energy efficiency, energy intensity, and carbon intensity in the *AEO2010* Reference case, 2008-2035 (index, 2008 = 1.0)

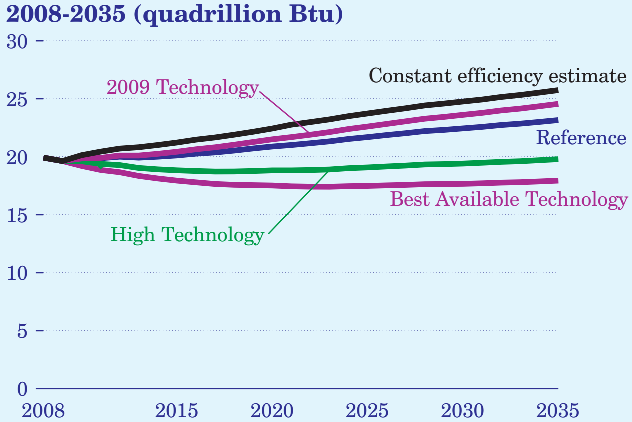


Comparing efficiency projections

Realized improvements in energy efficiency generally rely on a combination of technology and economics [*47*]. The figure below illustrates the role of technology assumptions in the *AEO2010* projections for energy efficiency in the residential and commercial buildings sector. Projected energy consumption in the Reference case is compared with projections in the Best Available Technology, High Technology, and 2009 Technology cases and an estimate based on an assumption of no change in efficiency for building shells and equipment (the cases are defined in Appendix E).

With the exception of the constant efficiency estimate, the rate at which existing equipment stocks are replaced in each of the cases is governed by the rate of stock turnover. The constant efficiency estimate assumes no stock turnover and no change in efficiency from the 2009 existing stock. The 2009 Technology case assumes a normal rate of stock turnover, but limits new equipment choices to what is available in 2009. Comparing the two projections, energy consumption in 2035 is 1.2 quadrillion Btu lower in the 2009 Technology case. The difference—about 4.5 percent—shows the effect of stock turnover even absent any technology improvements.

Delivered energy consumption in the residential and commercial buildings sector in five scenarios, 2008-2035 (quadrillion Btu)



In the Best Available Technology case, with new construction materials and replacement equipment limited to the most energy-efficient available, energy consumption in the buildings sector in 2035 is 8.6 percent lower than the 2009 level and 23 percent lower than in the Reference case, even though total floorspace grows by more than 50 percent. Even in 2035, however, not every piece of equipment or every building shell reaches the maximum efficiency that could be achieved as a result of technology improvements, because some long-lived equipment and building shells installed before 2009 still have not been replaced at that point. Surpassing the efficiency levels projected in the Best Available Technology case would require policies designed to increase the rate of stock turnover—for example, by incentivizing or mandating retrofits of existing buildings and replacement of equipment with the most efficient models available.

larger reduction in the index for carbon intensity reflects a shift toward less carbon-intensive energy sources in the Reference case, especially wind, biofuels, and solar. In the Reference case, the ratio of carbon emissions to energy consumption in 2035 is 5 percent lower than its 2008 value.

Energy consumption increases at an average annual rate of 0.5 percent from 2008 to 2035 in the *AEO2010* Reference case. The portion of the energy intensity decline projected in the Reference case that can be attributed to structural changes and the portion that can be attributed to changes in energy efficiency is illustrated by comparing the growth of primary energy use in the Reference case with estimates of constant energy efficiency and constant energy intensity, calculated from the *AEO2010* Reference case (Figure 19).

Assuming no improvement in energy intensity beyond 2008, energy consumption would grow in the Reference case at the rate of real GDP, 2.4 percent annually, to 192 quadrillion Btu in 2035—77.6 quadrillion Btu (68 percent) higher than in the Reference case. Similarly, assuming no change in energy efficiency beyond its 2008 level, energy consumption would increase to 132.8 quadrillion Btu in 2035, or 18.3 quadrillion Btu (16 percent) higher than in the Reference case. The intensity decline from structural change in the Reference case, 59.2 quadrillion Btu, is the difference between the projection for energy consumption in 2035 when no change in energy intensity is assumed and the same projection when no change in energy efficiency is assumed. Thus, structural change accounts for 76 percent of the decline in energy intensity in the Reference case, and efficiency improvement accounts for 24 percent.

Figure 19. Structural and efficiency effects on primary energy consumption in the *AEO2010* Reference case (quadrillion Btu)

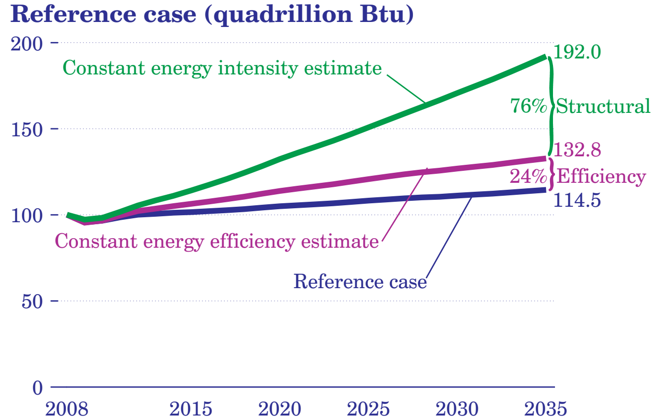


Table 4 shows average annual growth rates from 2008 to 2035 for real GDP, population, and major indicators for energy consumption in the end-use sectors in the Reference case. Because the growth rate for real GDP is higher than any of the other growth rates, energy consumption in each sector would be expected to grow more slowly than real GDP, and energy intensity would be expected to decline, even in the absence of efficiency gains.

In each of the end-use sectors, most of the improvement (decline) in energy intensity results from structural change: 82 percent in the buildings sectors, where average annual increases in residential and commercial floorspace are only about one-half the average increase in real GDP; 82 percent in the industrial sector, where output from non-energy-intensive manufacturing grows at twice the rate of output from energy-intensive manufacturing; and 53 percent in the transportation sector, where structural change is slower and improvements in fuel efficiency as a result of tightening fuel economy standards account for 47 percent of the decline in energy intensity. (For further discussion of efficiency in the *AEO2010* buildings cases, see box on page 31.)

Results for the Integrated Technology cases

The *AEO2010* Low Technology case assumes that the efficiency of newly purchased equipment does not improve beyond what is currently available (although end-use or process efficiency does improve to some extent as a result of stock turnover, because replacement equipment nearly always is more efficient than the equipment it replaces). The High Technology case

Table 4. Average annual increases in economic output, population, and energy consumption indicators in the buildings, industrial, and transportation sectors, 2008-2035 (percent per year)

Real GDP	**2.4**
Population	**0.9**
Buildings sector	
Number of households	1.0
Commercial floorspace	1.3
Industrial sector	
Real value of industrial shipments	
Nonmanufacturing	0.9
Energy-intensive manufacturing	0.8
Non-energy-intensive manufacturing	1.8
Transportation sector	
Vehicle miles traveled	
Light-duty vehicles	1.7
Freight trucks	1.7
Air seat-miles	1.3
Rail ton-miles	0.8

assumes earlier availability of high-efficiency technologies and lower technology costs than in the Reference case. Also, in a departure from previous *AEO*s, the *AEO2010* High Technology case assumes that consumers are more likely to choose advanced technologies, because they evaluate efficiency investments at a 7-percent real discount rate, which is generally lower than assumed in the Reference case.

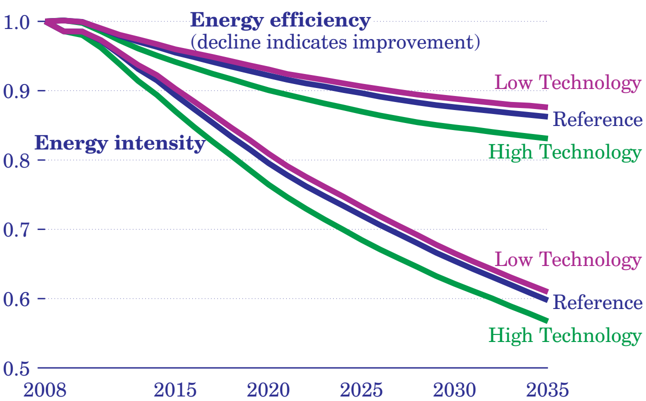
In the Low Technology and High Technology cases, projections for energy consumption in 2035 are 2.4 quadrillion Btu (2 percent) higher and 5.7 quadrillion Btu (5 percent) lower, respectively, than in the Reference case. Energy efficiency and intensity trends in the Reference, Low Technology, and High Technology cases are shown in Figure 20. From 2008 to 2035, there is a 12- to 17-percent improvement in energy efficiency across the three cases and a 39- to 43-percent reduction in intensity.

The relatively narrow range of projections in Figure 20 indicates that, although technology advances play a role in reducing energy intensity and carbon intensity, structural components are much more significant. Population shifts to more moderate climates, smaller households, less energy-intensive manufacturing, and more fuel-efficient LDVs and high-speed rail could further reduce energy intensity. Policies governing future CO_2 emissions and deployment of low- and no-carbon technologies will be the main determinant of future carbon intensity.

Natural gas as a fuel for heavy trucks: Issues and incentives

Environmental and energy security concerns related to petroleum use for transportation fuels, together with recent growth in U.S. proved reserves and technically recoverable natural gas resources, including

Figure 20. Energy efficiency and energy intensity in three cases, 2008-2035 (index, 2008 = 1.0)



shale gas, have sparked interest in policy proposals aimed at stimulating increased use of natural gas as a vehicle fuel, particularly for heavy trucks. In 2008, U.S. freight trucks used more than 2 million barrels of petroleum-based diesel fuel per day. In the *AEO-2010* Reference case, they are projected to use 2.7 million barrels per day in 2035. Petroleum-based diesel use by freight trucks in 2008 accounted for 15 percent of total petroleum consumption (excluding biofuels and other non-petroleum-based products) in the transportation sector (13.2 million barrels per day) and 12 percent of the U.S. total for all sectors (18.7 million barrels per day). In the Reference case, oil use by freight trucks grows to 20 percent of total transportation use (13.7 million barrels per day) and 14 percent of the U.S. total (19.0 million barrels per day) by 2035. The following analysis examines the potential impacts of policies aimed at increasing sales of heavy-duty natural gas vehicles (HDNGVs) and the use of natural gas fuels, and key factors that lead to uncertainty in these estimates.

Historically, natural gas has played a limited role as a transportation fuel in the United States. In 2008, natural gas accounted for 0.2 percent of the fuel used by all highway vehicles and 0.2 percent of the fuel used by heavy trucks—the market that many observers believe to be the most attractive for increasing the use of natural gas. Because there are relatively few heavy vehicles that use natural gas for fuel currently, there has been very little development of natural gas fueling infrastructure. Currently there are 827 fueling stations for CNG and 38 fuel stations for LNG in the United States. Most are privately owned and are used for central refueling [*48*]. Further, they are not distributed evenly: 24 percent (201) of the CNG facilities and 71 percent (27) of the LNG facilities are in California. Unless more natural gas vehicles enter the market, there will be little incentive to build more natural gas fueling infrastructure nationally or in local or regional corridors.

Despite the price advantage that natural gas has had over diesel fuel in recent years (an advantage that is projected to increase over time in the Reference case), other factors—including higher vehicle costs, lower operating range, and limited fueling infrastructure—have severely limited market acceptance and penetration of natural gas vehicles. As of 2008, trucks powered by natural gas made up only 0.3 percent of the heavy truck fleet, or about 27,000 of the 8.7 million registered heavy trucks. Although their share grows in the Reference case projections, high incremental costs keep the fleet of HDNGVs relatively small, at 1.7 percent (260,000 vehicles) of the total stock of 15 million heavy trucks on the road in 2035.

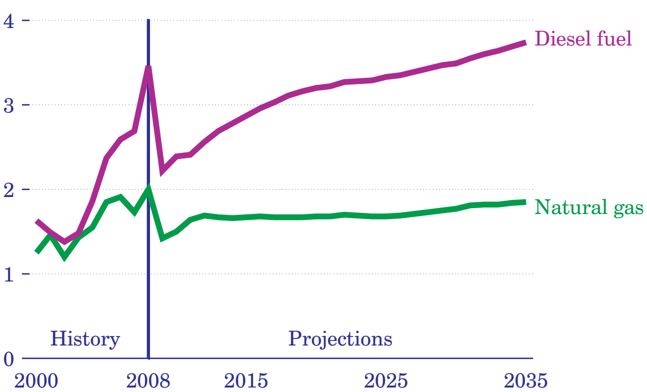
Characteristics and usage of heavy-duty natural gas vehicles

HDNGVs have significant incremental costs relative to their diesel-powered counterparts in the *AEO2010* Reference case: $17,000 for light-heavy (class 3, GVWR of 10,000 to 14,000 pounds), $40,000 for medium-heavy (classes 4 through 6, GVWR of 14,001 to 26,000 pounds), and $60,000 for heavy trucks (classes 7 and 8, GVWR of 26,001 pounds and greater). By far the largest component of incremental cost is the fuel storage system, which consists either of cylindrical tanks to hold CNG at high pressure or of highly insulated tanks to hold LNG. Because tank technology is fairly mature and, in the case of cylindrical tanks to hold gases at high pressure, is already widely deployed, the Reference case does not assume significant reductions in incremental vehicle costs over time.

Natural gas for use in transport vehicles currently costs 42 percent less than diesel fuel (on an energy-equivalent basis and considering only existing taxes), and with oil prices rising at a significantly faster rate than U.S. natural gas prices, the gap is projected to widen to 50 percent in 2035 in the *AEO2010* Reference case (Figure 21). Consequently, the payback period for incremental vehicle costs becomes shorter when natural gas trucks are used more intensively.

The Department of Transportation's Vehicle Inventory and Use Survey (VIUS), last completed in 2002, suggests a wide range for the intensity of heavy truck use. Notably, in the 2002 VIUS, trucks reporting a primary range of operation that extended more than 500 miles from their base averaged 91,000 vehicle-miles traveled (VMT), or more than 5 times the average of 17,000 VMT for trucks reporting a primary range of operation range within 100 miles of their base.

Figure 21. Delivered energy prices for diesel and natural gas transportation fuels in the Reference case, 2000-2035 (2008 dollars per gallon of diesel equivalent)



Although long-distance trucking offers a potentially faster payback of the incremental capital costs for HDNGVs, their penetration and acceptance in the long-distance freight market faces two significant barriers: limited driving range without refueling and a lack of available fueling infrastructure. A diesel truck with one 150-gallon diesel tank and a fuel economy of 6 to 7 mpg can drive approximately 1,000 miles without refueling, which can be extended readily with an auxiliary fuel tank. In contrast, a CNG-fueled truck with a frame-rail-mounted storage tank can drive only about 150 miles without refueling, while one with a back-of-cab frame-mounted storage tank can drive about 400 miles without refueling, similar to an LNG-fueled truck with frame-rail-mounted tanks. In addition, regardless of fuel type, long-distance trucks are less likely to be fueled at central bases, which makes them more dependent on fueling infrastructure that is open to the public.

In addition to concerns about driving range and refueling, the residual value of HDNGVs in the secondary market is likely to be an important consideration for buyers. Also, purchase decisions can be influenced by other factors, such as weight limits on highways and bridges, which can make the considerable additional weight of CNG or LNG tanks a significant drawback in some market segments.

The importance of range and refueling infrastructure barriers suggests that the best near-term market penetration opportunity for HDNGVs, some of whose incremental costs are already covered by tax credits, could be in the market for centrally fueled fleets that operate primarily within a limited distance from their base. The 2002 VIUS reported a total of 145 billion truck VMT (not counting light trucks used primarily for personal transportation), of which about 50 percent was made up by trucks with a primary operating range of 200 miles or less and about one-third by trucks fueled at private facilities (presumably, with considerable overlap between the two groups). Accordingly, the following analysis focuses on "fleet vehicles" in the short-range (less than 200 miles), centrally fueled segment of the heavy truck market.

Sensitivity cases with incentives for heavy-duty natural gas vehicles

Policies that provide economic incentives—such as tax credits for vehicles, fuel, and fueling infrastructure—could stimulate sales of HDNGVs and the development of additional natural gas fueling infrastructure. *AEO2010* includes several sensitivity cases that examine the potential impacts of such incentives.

The **Reference Case 2019 Phaseout With Base Market Potential** is a modified Reference case that incorporates lower incremental costs for all classes of HDNGVs (zero incremental cost relative to their diesel-powered counterparts after accounting for incentives) and tax incentives for natural gas refueling stations ($100,000 per new facility) and for natural gas fuel ($0.50 per gallon of gasoline equivalent) that begin in 2011 and are phased out by 2019.

The **Reference Case 2027 Phaseout With Expanded Market Potential** is another modified Reference case with the same added assumptions of lower incremental costs for HDNGVs and subsidies for fueling stations and natural gas fuel as in the first modified Reference case, but with the subsidies extended to 2027 before phaseout. In addition, it assumes increases in the potential market for natural gas vehicles, for both "fleet vehicles" and "nonfleet vehicles" (see Table 5).

In the following text and data presentations, the cases above are referred to more briefly as the 2019 Phaseout Base Market case and 2027 Phaseout Expanded Market case.

HDNGVs cannot gain a major share of the heavy truck market in the absence of major investments in natural gas fueling infrastructure. The assumed $100,000 tax credit per filling station is a relatively small percentage of the estimated $1 million to $4 million cost for such facilities. Assuming an initial cost of $2 million per station, Table 6 shows the levelized capital cost of the station per gallon of diesel equivalent refueling capacity with and without the $100,000 tax credit, for station fuel throughput capacities of 1,250, 5,000, and 12,500 gallons per day [*49*].

As indicated in Table 6, increasing the throughput capacity of a fueling station from 1,250 to 5,000 gallons diesel equivalent per day lowers the capital cost recovery component of supplying natural gas fuel to HDNGVs by more than $1.00 per gallon of diesel equivalent. The infrastructure tax credit lowers the capital cost recovery component by only an additional 8 cents per gallon for the smallest facility size shown in the table and by only 1 cent per gallon for the largest facility size. This suggests that throughput capacity (demand) is a far more important consideration for decisions about investment in natural gas fueling stations than are potential tax credits on the order of about $100,000.

Impacts of incentives in the Base Market and Expanded Market cases with Reference case world oil price assumptions

In the 2019 Phaseout Base Market and 2027 Phaseout Expanded Market cases, both of which use oil price assumptions from the *AEO2010* Reference case, HDNGV sales increase with the availability of incentives. Assuming a 2019 phaseout date for tax credits and the base characterization of maximum penetration of the new truck market, sales of new HDNGVs in the 2019 Phaseout Base Market case increase from about 500 in 2008 to 32,500 in 2035, versus 22,000 in the Reference case (Figure 22). Assuming a 2027 phaseout of tax credits and the expanded characterization of maximum market penetration, HDNGV sales in the 2027 Phaseout Expanded Market case increase to 270,000 in 2035, or roughly 35 percent of

Table 5. Maximum market potential for natural gas heavy-duty vehicles in Base Market and Expanded Market cases (percent of total heavy-duty vehicle fleet)

Vehicle type and class	Base Market	Expanded Market
Fleet vehicles		
Class 3	10	35
Classes 4-6	10	45
Classes 7-8	10	60
Nonfleet vehicles		
Class 3	3	10
Classes 4-6	3	25
Classes 7-8	3	25

Table 6. Levelized capital costs for natural gas fueling stations with and without assumed tax credits (2008 dollars per gallon of diesel equivalent refueling capacity)

Station capacity (gallons equivalent per day)	Cost without credits	Cost with credits
1,250	1.47	1.39
5,000	0.37	0.35
12,500	0.15	0.14

all new heavy truck sales. The HDNGV share of the total U.S. heavy truck stock in 2035 is 2.8 percent in the 2019 Phaseout Base Market case and 23.3 percent in the 2027 Phaseout Expanded Market case (versus 1.7 percent in the Reference case).

As a result of the projected increases in new HDNGV sales, natural gas demand in the heavy truck sector increases from about 0.01 trillion cubic feet in 2008 to 0.15 trillion cubic feet in 2035 in the 2019 Phaseout Base Market case and to 1.6 trillion cubic feet in 2035 in the 2027 Phaseout Expanded Market case (Figure 23). In the Reference case, the natural gas share of total fuel consumption by heavy trucks increases from 0.2 percent in 2008 to 1.8 percent in 2035; in the 2019 Phaseout Base Market and 2027 Phaseout Expanded Market cases, it increases to 3.3 percent and 40.0 percent, respectively.

Figure 22. Sales of new heavy-duty natural gas vehicles in Base Market and Expanded Market cases with Reference case world oil prices, 2010-2035 (thousands of vehicles)

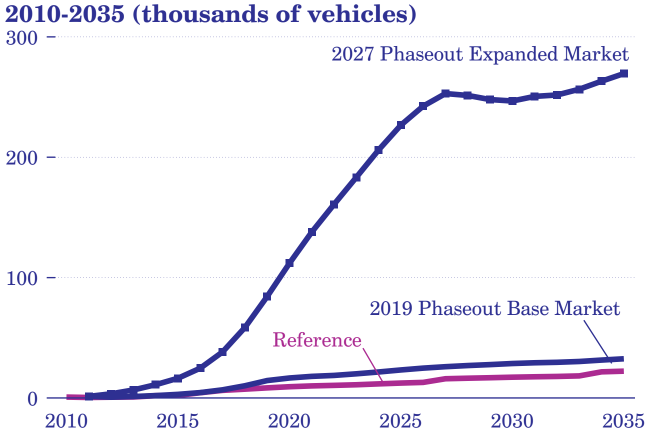
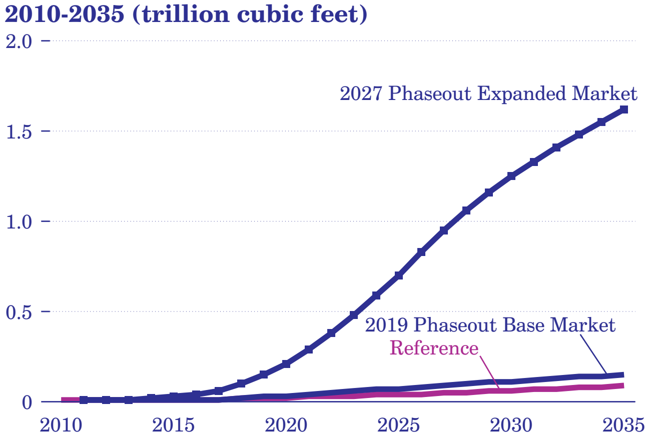


Figure 23. Natural gas fuel use by heavy-duty natural gas vehicles in Base Market and Expanded Market cases with Reference case world oil prices, 2010-2035 (trillion cubic feet)

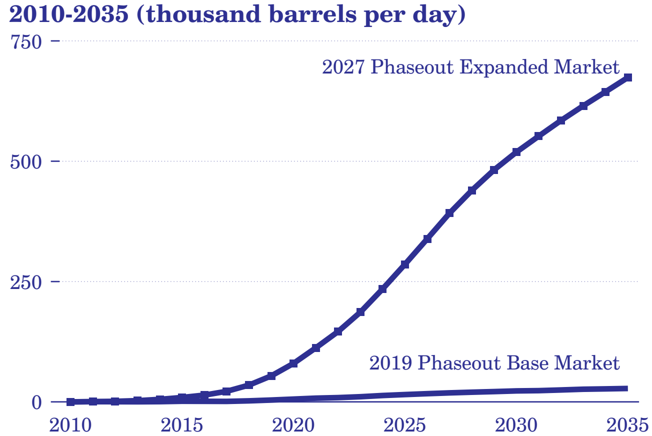


Roughly speaking, 1 trillion cubic feet of natural gas replaces 0.5 million barrels per day of petroleum (predominantly, diesel fuel). Thus, natural gas consumption by HDNGVs in the 2027 Phaseout Expanded Market case displaces about 0.67 million barrels per day of petroleum product consumption in 2035 (Figure 24). Without a major impact on world oil prices, which is not expected to result from the significant but gradual adoption of natural gas as a fuel for U.S. heavy-duty vehicles, nearly all (more than four-fifths) of the reduction in U.S. oil consumption would result in a decline in oil imports.

In the longer term, increased demand for natural gas in the transportation sector would tend to stimulate increases in U.S. natural gas production and imports, as well as higher natural gas prices in all the end-use sectors. As a result, natural gas demand in the other sectors would decrease—particularly in the electric power sector, where some generators would switch to coal—and expenditures for natural gas would increase. In the *AEO2010* Reference case, total U.S. natural gas consumption increases from 23.3 trillion cubic feet in 2008 to 24.9 trillion cubic feet in 2035. In the 2019 Phaseout Base Market case and 2027 Phaseout Expanded Market case, total natural gas consumption increases by 0.4 percent, to 25.0 trillion cubic feet, and by 4.8 percent, to 26.1 trillion cubic feet, respectively, in 2035.

In the 2019 Phaseout Base Market case and 2027 Phaseout Expanded Market case, more than two-thirds of the additional natural gas used by HDNGVs is produced domestically, and less than one-third is provided by increases in pipeline imports from Canada and LNG imports. U.S. natural gas prices rise modestly in both cases.

Figure 24. Reductions in petroleum product use by heavy-duty vehicles in Base Market and Expanded Market cases with Reference case world oil prices, 2010-2035 (thousand barrels per day)



Impacts of incentives in the Base Market and Expanded Market cases with low world oil price assumptions

Lower oil prices tend to make HDNGVs a less attractive option, and higher oil prices tend to make them more attractive. In the two sensitivity cases discussed above, which assumed Reference case world oil prices, market penetration by HDNGVs reaches or nearly reaches its assumed maximum market potential. As a result, higher oil prices would not lead to further increases in HDNGV sales, unless the large price advantage of natural gas were sufficient to open additional segments of the heavy truck transportation market to the use of natural-gas-fueled vehicles.

On the other hand, if oil prices were lower than projected in the Reference case, there would be less incentive to switch from diesel to natural gas fuel in heavy trucks. With no tax incentives or assumed market expansion for HDNGVs, there are almost no sales of new HDNGVs in 2035 in the *AEO2010* Low Oil Price case. To analyze the impact of lower oil prices, EIA ran two sensitivity cases that were identical to those discussed earlier but instead used the Low Oil Price case. In the 2019 Phaseout Base Market Low Price case, sales of new HDNGVs total about 17,000 in 2035. In the 2027 Phaseout Expanded Market Low Price case, sales of new HDNGVs total about 205,000 in 2035. Similarly, natural gas consumption by HDNGVs increases to 0.1 trillion cubic feet in 2035 in the 2019 Phaseout Base Market Low Price case and to 1.2 trillion cubic feet in the 2027 Phaseout Expanded Market Low Price case, as compared with almost no demand for natural gas in the heavy vehicle sector in 2035 in the *AEO2010* Low Oil Price case.

Incentive costs and impacts on energy expenditures

Increased use of natural gas as a transportation fuel changes the levels of demand for, and consequently the prices of natural gas and other fuels used in transportation and other sectors of the economy. Depending on the amount of natural gas used in the transportation sector, the sum of incentive payments to the transportation sector plus higher energy costs to other sectors may be more than offset by savings in the transportation sector from fuel switching from diesel to natural gas. Figure 25 shows annual vehicle and fuel tax incentive payments and net changes in economy-wide energy expenditures for the 2027 Phaseout Expanded Market case [*50*]. The graph shows how changes in transportation demand for natural gas and petroleum products may affect energy expenditures throughout the economy while the incentives are in effect. The significant increase in transportation natural gas use and associated reductions in petroleum product use result in increases in economy-wide natural gas prices and expenditures that are more than offset by economy-wide decreases in petroleum product prices and expenditures.

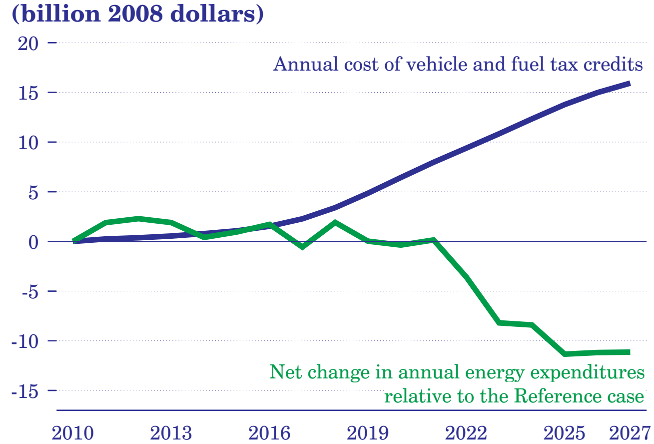
The projections in Figure 25 do not reflect many of the factors that could be important for policymakers' evaluations of incentives for HDNGVs, such as the cost of infrastructure tax credits, productivity losses resulting from more frequent refueling, impacts on net energy costs, incremental vehicle costs beyond the period when incentives are provided, or environmental benefits of reducing emissions of conventional pollutants and GHGs. Also, they do not consider potential effects on royalty and severance payments as a result of changes in domestic natural gas production or oil imports, or effects on GDP and other relevant indicators of economic welfare and energy security.

Factors affecting the relationship between crude oil and natural gas prices

Background

Over the 1995-2005 period, crude oil prices and U.S. natural gas prices tended to move together, which

Figure 25. Annual cost of vehicle and fuel tax credits and net change in annual economy-wide energy expenditures for the 2027 Phaseout Expanded Market case, 2010-2027 (billion 2008 dollars)



supported the conclusion that the markets for the two commodities were connected. Figure 26 illustrates the fairly stable ratio over that period between the price of low-sulfur light crude oil at Cushing, Oklahoma, and the price of natural gas at the Henry Hub on an energy-equivalent basis.

The *AEO2010* Reference and High Oil Price cases, however, project a significantly longer and persistent disparity between the relative prices of low-sulfur light crude oil and natural gas on an energy-equivalent basis [*51*]. The apparent disconnect in prices between seemingly similar commodities varies over a wide range between 2010 and 2035 [*52*]. Over much of the projection period in the Reference case, the crude oil price is about 2.8 times the natural gas price on an energy equivalent basis—115 percent higher than the historical average price ratio of 1.3 from 1995 to 2005. In the High Oil Price case, the ratio widens to as much as 4.8; in the Low Oil Price case, it narrows from nearly 3.0 in 2009 to 1.1 in 2035.

Such an apparent lack of responsiveness of natural gas prices to changes in crude oil prices in all cases reflects the changes that have occurred in the underlying uses of the two commodities. The divergence of crude oil and natural gas markets also reflects the fact that opportunities for the substitution of natural gas for crude oil products are limited by the large infrastructure investments that would be required to allow substitution on a significant scale and bring the prices of the two commodities closer together in the U.S. market in the Reference and High Oil Price cases. In the absence of such investments, EIA expects the gap between oil and natural gas prices in U.S. energy markets to remain wide.

Opportunities to substitute natural gas for petroleum

In the United States, the capability to substitute natural gas supplies directly for petroleum, particularly in the electric power sector, has eroded over time. In 1978, 4.0 quadrillion Btu of petroleum was consumed to produce electricity, representing nearly 17 percent of total energy use for U.S. electricity generation, as compared with 14 percent for natural gas [*53*]. In 2008, only 0.5 quadrillion Btu of petroleum was consumed for electricity generation, representing 1.2 percent of total energy use for generation [*54*, *55*], while natural gas has grown to 17 percent of generation. The trend has been similar in the commercial and industrial sectors where there are a declining number of opportunities to substitute natural gas for petroleum.

Still, there are potential opportunities for natural gas to displace petroleum. First, direct use of natural gas in the U.S. transportation sector could provide an opportunity for substitution. Second, natural gas could be exported to countries where petroleum is widely used for thermal applications. Third, natural gas can be converted directly to petroleum-like liquid fuels that could be substituted for diesel and gasoline in the existing vehicle fleet using the existing distribution infrastructure.

The physical properties of natural gas are such that it is more difficult and costly than liquid fuels to transport and consume. As shown in Figure 27, the energy density of natural gas is much lower than that of most liquid fuels. To match the energy equivalent of a 1-gallon container of diesel fuel, a balloon of natural gas at atmospheric pressure would have to be nearly a thousand times larger than the gallon container. At a

Figure 26. Ratio of low-sulfur light crude oil prices to natural gas prices on an energy-equivalent basis, 1995-2035

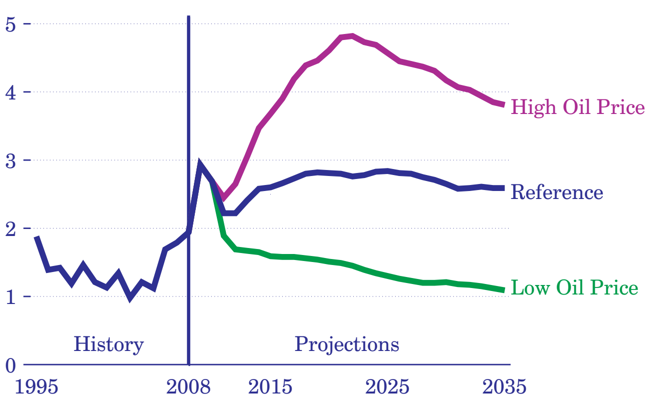
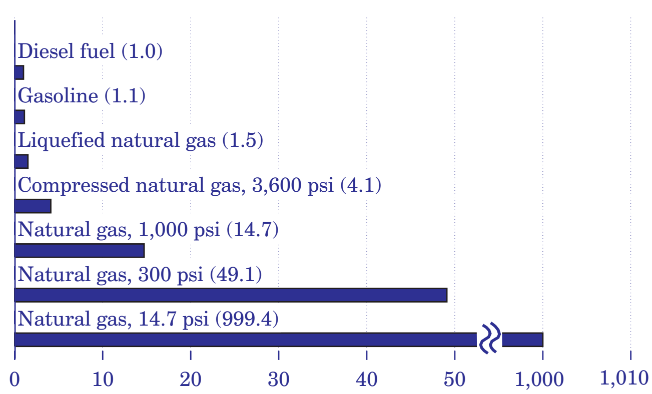


Figure 27. Ratio of natural gas volume to diesel fuel volume needed to provide the same energy content



pressure of 3,600 pounds per square inch (psi), however, which is the pressure rating for the fuel tanks used in CNG vehicles, only 4 times as much space is required to match the energy equivalent of 1 gallon of diesel fuel. And when the gas is converted to LNG by chilling to about -260 degrees Fahrenheit, its energy density increases to the point where it requires only 50 percent more volume to match the energy content of diesel fuel. However, the materials used for the handling and storage of LNG differ significantly from those used for CNG or petroleum-like liquid fuels.

An expanded market for CNG or LNG would require additional investment in vehicles and infrastructure for compression and storage of CNG or for liquefaction and storage of LNG. Some of the issues, challenges, and opportunities surrounding the use of natural gas as a substitute for diesel fuel are described in the Issues in Focus section, “Natural gas as a fuel for heavy trucks: Issues and incentives.”

Barriers to U.S. exports of LNG

World crude oil and natural gas prices could converge if barriers to the flow of natural gas between U.S. and world markets were eliminated through the combined use of the existing pipeline network, existing LNG terminals, and investment in new U.S. LNG liquefaction capacity (and possibly LNG tankers) to allow exports of U.S. natural gas when it is economical. Currently, there is one liquefaction facility in Alaska that exports LNG from the United States. Investment in new U.S. liquefaction capacity would face significant risk, however, because there are large quantities of “stranded gas” in remote regions of the world that can be priced well below the expected cost of resources in the lower 48 States.

Potential for production of liquid fuels from natural gas

Another opportunity to substitute natural gas for crude oil would be to convert it to petroleum-like liquid products similar to gasoline and diesel fuel, for use in the liquid fuel infrastructure and end-use equipment. Such a transformation is possible through use of the GTL process.

There are several GTL processes, the best known using a Fischer-Tropsch reactor. The reactor produces a paraffin wax that is hydrocracked to form liquid products that resemble petroleum liquids. Distillates, including diesel, heating oil, and jet fuel, are the primary products, making up 50 to 70 percent of the total volume produced, and naphtha usually represents about 25 percent of the volume. The process efficiency is about 57 percent (43 percent of the energy content of the natural gas is lost in the process) [*56*]. Thus, the price ratio of liquid products to natural gas would have to exceed about 1.8 to justify operation of the plant, excluding consideration of other operating costs and the cost of capital investment. To appreciate the price risk faced by investors, one can consider the effects of recent fluctuations in energy prices on investments in U.S. natural gas turbine and combined-cycle generating units and ethanol production facilities [*57*]. Indeed, *AEO2010* examines the potential impacts of lower energy prices in the Low Oil Price case, which shows the ratio of crude oil prices to natural gas prices declining to 1.1 in 2035, indicating that if any GTL plants were built they would not be operated under those price conditions.

The technologies and equipment used in the best-known GTL technology are similar to those that have been employed for decades in methanol and ammonia plants, and most are relatively mature; however, the scale on which previous GTL plants have been implemented is relatively small. The newest GTL plants have been expanded to much larger sizes, including one in excess of 100,000 barrels per day, to take advantage of economies of scale, but recent attempts to build projects at those larger sizes have encountered technology or project execution risks [*58*]. Currently, there are four GTL plants in operation worldwide, with 96,200 barrels per day of total capacity [*59*]. In addition, two projects with 174,000 barrels per day of capacity are under construction or ready for startup [*60*]. However, the construction of GTL plants at sites with available stranded gas reserves has been limited, indicating investor reluctance to pursue this option fervently, especially when investments in less capital-intensive LNG capacity are possible. Indeed, some GTL projects have been canceled or deferred in the past few years [*61*].

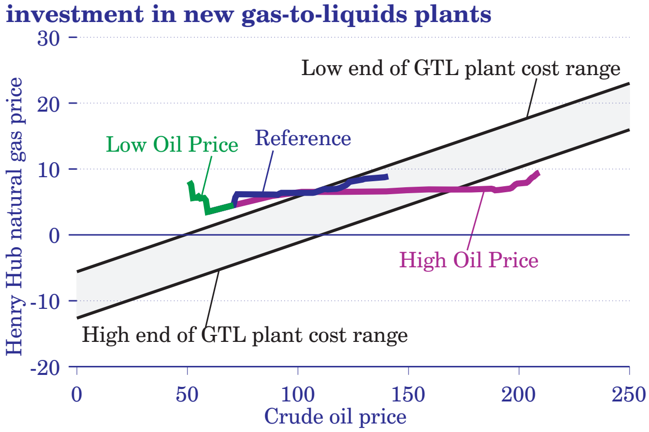
The overnight capital costs for a new GTL plant situated on the U.S. Gulf Coast would range from $50,000 per barrel-stream day of capacity [*62*] to an estimated $104,000 per barrel-stream day [*63*]. Accordingly, a relatively modest unit with a capacity of 34,000 barrels per day represents an estimated overnight capital cost [*64*] of $1.7 billion to $3.5 billion. With financing included, the estimated total investment would be $2.2 billion to $4.4 billion. In addition, construction of the facility would take 4 years or more, imposing further market risk. The risk-adjusted discount factor used by investors will be critical to determining whether investors would proceed with GTL investments.

Figure 28 shows the maximum "breakeven" average price of natural gas that could be tolerated over a 10-year plant operating period [*65*] in order to justify the risk associated with investing in a GTL facility, based on the range of capital costs discussed above and a 10-percent hurdle rate [*66*]. Profitable cases lie below the line. At $100 per barrel for crude oil, the breakeven price for natural gas that would justify investment in a GTL facility is -$1.20 to $5.80 per million Btu. At higher crude oil prices, the range of the breakeven natural gas price also rises. At a crude oil price of $200 per barrel, the breakeven price for natural gas is $10.20 to $17.30 per million Btu. At a crude oil price of $60 per barrel, the breakeven natural gas price ranges from -$5.80 to $1.30 per million Btu, illustrating the substantial impact of oil price uncertainty on the profitability of investment in a GTL facility.

Figure 28 also shows how investment in a GTL facility would fare with the natural gas and crude oil price projections in the *AEO2010* Reference, Low Oil Price, and High Oil Price cases. With the prices in the Low Oil Price case, GTL is a poor investment. With the prices in the Reference case, GTL is a marginal investment. Only with the highest prices in the Reference case and the low end of GTL plant costs do the breakeven economics favor the project. In the High Oil Price case, however, the combination of higher crude oil prices and lower natural gas prices implies that investment in a GTL plant on the U.S. Gulf Coast could be profitable.

A large investment in GTL would be needed in order to produce an appreciable effect on worldwide prices for crude oil and U.S. natural gas. Construction of sufficient new GTL capacity to affect world crude oil prices, about 1 million barrels per day, would require a total investment between $50 billion and $135 billion. That level of capacity would still represent only 1.2 percent of the 85.9 million barrels per day of the world's estimated total liquids production in 2007 [*67*], and less than 1 percent of projected 2035 production in the Reference case [*68*].

Figure 28. Breakeven natural gas price (2008 dollars per million Btu) relative to crude oil price (2008 dollars per barrel) required for investment in new gas-to-liquids plants



Another option is the potential use of stranded natural gas in Alaska to produce GTL. Because of Alaska's severe weather conditions, construction of GTL (or any other) facilities is likely to be much more expensive than the construction of GTL plants on the U.S. Gulf Coast or in the Middle East. Some estimates suggest that doubling the construction costs and extending the construction period by at least 2 years would be reasonable assumptions. Construction of GTL facilities in Alaska, therefore, seems unlikely given the cost uncertainties mentioned above and the crude oil price projections in the *AEO2010* Reference case.

Looking forward

A large disparity between crude oil and natural gas prices, as projected in the *AEO2010* Reference and High Oil Price cases, will provide incentives for innovators and entrepreneurs to pursue opportunities that, in the longer term, could increase domestic or international markets for U.S. natural gas. For example, a scenario with relatively high oil prices would tend to increase the value of CO_2 used for EOR as well as GTL production. Because GTL processing plants can accommodate natural gas feedstocks with relatively high CO_2 content and can target fields smaller than those required for LNG production, such circumstances would provide incentives for the development of smaller GTL systems that produce both liquid products and a valuable CO_2 co-product. Because EIA cannot predict whether or when such innovations might arise, they are not included in the *AEO2010* analysis cases.

Importance of low-permeability natural gas reservoirs

Introduction

Production from low-permeability reservoirs, including shale gas and tight gas, has become a major source of domestic natural gas supply. In 2008, low-permeability reservoirs accounted for about 40 percent of natural gas production and about 35 percent of natural gas consumption in the United States. Permeability is a measure of the rate at which liquids and gases can move through rock. Low-permeability natural gas reservoirs encompass the shale, sandstone, and carbonate formations whose natural permeability is roughly 0.1 millidarcies or below. (Permeability is measured in “darcies.”)

The use of hydraulic fracturing in conjunction with horizontal drilling in shale gas formations and the use of hydraulic fracturing in tight gas formations has opened up natural gas resources that would not be commercially viable without these technologies. As shale gas production has expanded into more basins and recovery technology has improved, the size of the shale gas resource base in the *AEO* has increased markedly. Because the exploitation of shale gas resources is still in its initial stages, and because many shale beds have not yet been tested, there is a great deal of uncertainty over the size of the recoverable shale gas resource base. Low-permeability gas wells typically produce at high initial flow rates, which decline rapidly and then stabilize at relatively low levels for the remaining life of the wells.

To illustrate the importance of low-permeability natural gas reservoirs for future U.S. natural gas supply, consumption, and prices, three alternative cases were developed for *AEO2010*: a No Shale Gas Drilling case, a No Low-Permeability Gas Drilling case, and a High Shale Gas Resource case. The No Shale Gas Drilling and No Low-Permeability Gas Drilling cases examine the implications of no new drilling in low-permeability formations. The High Shale Resource case examines the possibility that shale gas resources could be considerably greater than those represented in the Reference case. The three alternative cases are *not* intended to represent any expected future reality. Rather, they are intended to illustrate the importance of low-permeability formations for EIA’s projections of future U.S. natural gas supply and are likely to be extremes. All the cases assume no change from the Reference case assumptions about the size of, and access to, Canadian and other international natural gas resources. Specific assumptions in the three cases are as follows.

No Shale Gas Drilling case. Starting in 2010, in this case no new onshore lower 48 shale gas production wells are drilled. Natural gas production from shale gas wells drilled before 2010 declines continuously through 2035.

No Low-Permeability Gas Drilling case. Starting in 2010, in this case no new onshore lower 48 low-permeability natural gas production wells are drilled, including shale gas wells and “tight” sandstone and carbonate gas wells. Natural gas production from low-permeability wells drilled before 2010 declines continuously through 2035.

High Shale Gas Resource case. In this case, the unexploited portion of each shale formation supports twice as many new wells as in the Reference case. The lower 48 shale gas resource base increases by 88 percent, from 347 trillion cubic feet in the Reference case to 652 trillion cubic feet in the High Shale Gas Resource case. The estimated recovery per well in each formation is the same as in the Reference case.

Natural gas supply, consumption, and prices

Low-permeability natural gas resources are more abundant and less expensive than other domestic natural gas supply alternatives that could replace them, and they are expected to play a significant role in future domestic natural gas markets. Consequently, their future absence or presence is expected to have a significant impact on the average cost of natural gas production and prices, which in turn would affect natural gas imports and consumption. In the No Shale Gas Drilling and No Low-Permeability Gas Drilling cases, lower 48 onshore natural gas productive capacity is less than in the Reference case, and as a result average U.S. natural gas prices are higher, more natural gas is imported, and natural gas consumption is reduced (Table 7). Conversely, in the High Shale Gas Resource case, natural gas productive capacity is higher, natural gas prices and imports are lower, and consumption is higher than projected in the Reference case.

No Shale Gas Drilling and No Low-Permeability Gas Drilling cases

In the No Shale Gas Drilling and No Low-Permeability Gas Drilling cases, total domestic natural gas production in 2035 is 18 percent and 25 percent lower, respectively, and onshore lower 48 production is 27 percent and 39 percent lower, respectively, than in the Reference case. The loss of onshore lower 48 productive capacity leads to higher natural gas prices and lower consumption levels. In the No Shale Gas Drilling and No Low-Permeability Gas Drilling cases, the Henry Hub spot price for natural gas in 2035 is $1.49 and $2.00 per million Btu higher, respectively, than the Reference case price of $8.88 per million Btu. The significantly higher natural gas prices are a result of the removal of considerable low-cost natural gas resources, leaving a smaller natural gas resource base that is more expensive to produce.

Because higher domestic natural gas prices make other supply sources more competitive, both offshore Gulf of Mexico production and net natural gas imports increase in the No Shale Gas Drilling and No Low-Permeability Gas Drilling cases. Offshore natural gas production levels in 2035 are 7 percent and 18 percent (0.3 trillion cubic feet and 0.8 trillion cubic feet) higher, respectively, than in the Reference case, and net imports are 154 percent and 207 percent higher (2.2 trillion cubic feet and 3.0 trillion cubic feet). In 2035, net imports make up 6 percent of total U.S. natural gas supply in the Reference case, 16 percent in the No Shale Gas Drilling case, and 20 percent in the No Low-Permeability Gas Drilling case. The higher levels of net imports in the two alternative cases are the result of increases in LNG imports and imports from Canada, as well as a reduction in exports to Mexico.

In 2035, net LNG imports in the No Shale Gas Drilling and No Low-Permeability Gas Drilling cases are more than double those in the Reference case (1.8, 2.4, and 0.8 trillion cubic feet, respectively), and net natural gas imports from Canada are 52 percent and 59 percent greater, respectively, in the two alternative cases than in the Reference case. Because the assumptions in these cases are not applied to the Canadian natural gas resource base, higher U.S. prices lead to more natural gas production in Canada (including Canadian shale gas). In addition, Canada's Mackenzie Delta natural gas pipeline begins operating before 2035 in the two alternative cases, which does not occur in the Reference case. Net natural gas exports to Mexico in 2035 are 35 percent and 47 percent lower in the No Shale Gas Drilling and No Low-Permeability Gas Drilling cases, respectively, than in the Reference case.

The impact on natural gas consumption of restricted drilling in low-permeability reservoirs is less pronounced than the impact on domestic supply, for two reasons. First, the increase in net imports partially offsets the reduction in domestic natural gas productive capacity. Second, long-lived natural gas consumption equipment responds more slowly to changes in natural gas prices than does natural gas supply—although the electric power sector, where natural gas consumption responds relatively quickly to changes in natural gas prices, is an exception. In 2035, natural gas consumption in the electric power sector is 1.3 trillion cubic feet (17 percent) lower in the No Shale Gas Drilling case and 1.9 trillion cubic feet (26 percent) lower in the No Low-Permeability Gas Drilling case than the Reference case level of 7.4 trillion cubic feet.

Table 7. Natural gas prices, supply, and consumption in four cases, 2035

Projection	Reference	No Shale Gas Drilling	No Low-Permeability Gas Drilling	High Shale Gas Resource
Henry Hub spot price (2008 dollars per million Btu)	8.88	10.37	10.88	7.62
Total U.S. natural gas production (trillion cubic feet)	**23.3**	**19.1**	**17.4**	**25.9**
Onshore Lower 48	17.1	12.5	10.4	20.0
Offshore Lower 48	4.3	4.7	5.1	4.0
Alaska	1.9	1.9	1.9	1.9
First year of operation for the Alaska natural gas pipeline	2023	2020	2020	2030
Total net U.S. imports of natural gas (trillion cubic feet)	**1.5**	**3.7**	**4.5**	**0.8**
Canada	1.7	2.5	2.7	1.4
Mexico	-1.0	-0.7	-0.5	-1.3
Liquefied natural gas	0.8	1.8	2.4	0.8
Total U.S. natural gas consumption (trillion cubic feet)	**24.9**	**22.9**	**22.0**	**26.8**
Electric power	7.4	6.1	5.5	8.7
Residential sector	4.9	4.8	4.7	5.0
Commercial sector	3.7	3.6	3.5	3.8
Industrial sector	6.7	6.5	6.4	7.0
Other	2.2	1.9	1.8	2.3

High Shale Gas Resource case

Relative to the Reference case, both natural gas production costs and prices are reduced in the High Shale Gas Resource case. Consequently, domestic natural gas production is more competitive, and U.S. natural gas consumption is higher. In 2035, onshore lower 48 and total natural gas production are 17 percent and 11 percent higher, respectively, in the High Shale Gas Resource case than in the Reference case, and Henry Hub spot prices are $1.26 per million Btu lower than in the Reference case. Increased domestic production and lower natural gas prices reduce net imports in 2035 by 44 percent from their level in the Reference case, to 0.8 trillion cubic feet, and offshore natural gas production in 2035 is reduced by 7 percent, to 4.0 trillion cubic feet. The decline in net imports results from a 19-percent reduction in net imports from Canada, an 8-percent reduction in net LNG imports, and a 25-percent increase in net exports to Mexico in the High Shale Gas Resource case, relative to the Reference case.

Because of the lower natural gas prices in the High Shale Gas Resource case, U.S. natural gas use in 2035 is 2.0 trillion cubic feet (8 percent) higher than in the Reference case. The majority of the increase is in the electric power sector, which accounts for 1.3 trillion cubic feet (18 percent) of the total increase.

U.S. nuclear power plants: Continued life or replacement after 60?

Background

Nuclear power plants generate approximately 20 percent of U.S. electricity, and the plants in operation today are often seen as attractive assets in the current environment of uncertainty about future fossil fuel prices, high construction costs for new power plants (particularly nuclear plants), and the potential enactment of GHG regulations. Existing nuclear power plants have low fuel costs and relatively high power output. However, there is uncertainty about how long they will be allowed to continue operating.

The nuclear industry has expressed strong interest in continuing the operation of existing nuclear facilities, and no particular technical issues have been identified that would impede their continued operation. Recent *AEO*s had assumed that existing nuclear units would be retired after 60 years of operation (the initial 40-year license plus one 20-year license renewal). Maintaining the same assumption in *AEO2010*, with the projection horizon extended to 2035, would result in the retirement of more than one-third of existing U.S. nuclear capacity between 2029 and 2035. Given the uncertainty about when existing nuclear capacity actually will be retired, EIA revisited the assumption for the development of *AEO2010* and modified it to allow the continued operation of all existing U.S. nuclear power plants through 2035 in the Reference case.

The modified assumption in the Reference case implies that the operating lives of some nuclear plants will be more than 60 years. To address the uncertainty about whether such life extensions will be allowed, an alternative Nuclear 60-Year Life case was developed, assuming that all the existing U.S. nuclear power plants will be retired after 60 years of operation.

Discussion

The Atomic Energy Act of 1954 authorized the U.S. Nuclear Regulatory Commission (NRC) to issue operating licenses for commercial nuclear power plants for a period of 40 years. The 40-year time frame was derived from accounting and anti-trust concerns, not technical limitations [*69*]. The law allows the NRC to issue operating license renewals in 20-year increments, provided that reactor owners demonstrate that continued operations can be conducted safely. As of July 2009, the NRC had granted license renewals to 50 of the 104 operating reactors in the United States, allowing them to operate for 60 years. Fifteen additional applications are under review, and the owners of 21 other units have announced that they intend to file for 20-year license extensions. The NRC has yet to deny an application for a 20-year extension [*70*]. Previous *AEO*s assumed that all of the 104 existing units would operate for a total of 60 years, provided that they remained economical.

In December 2009, the Oyster Creek Generating Station in Lacey Township, New Jersey, became the first nuclear power plant in the United States to begin its 40th year of operation. With Oyster Creek and other nuclear plants of similar vintage just beginning to enter their first period of license renewal, it probably will be at least 5 to 10 years before there is any clear indication as to whether plant operators will be likely to seek further extensions of their plants' operating lives.

For the *AEO2010* Reference case, EIA assumed that the operating lives of existing nuclear power plants would be extended at least through 2035. Assuming that the NRC continues to approve license extensions, the decision to operate a facility is an economic one made by plant owners. Aging plants may face increased operation and maintenance (O&M) costs and capital expenditures, which generally decrease their profitability. Revenue projections are dependent on electricity prices, which are uncertain due to variations in fossil fuel prices, regional economic growth, and environmental regulations. Thus, even if the costs of operating nuclear plants do not change, changes in electricity prices can affect their profitability when their generation is sold at market-based rates.

Between 1974 and 1998, 14 commercial nuclear reactors in the United States were retired. The circumstances of each retirement were unique to the particular plant, but the common thread was that the expected cost of continued operation was higher than expected revenues, and there were less costly generating options available. Highly competitive natural-gas-fired generation could have been a factor in those retirements. Natural-gas-fired combined-cycle plants were the favored option for new capacity during the 1990s, when natural gas prices were relatively low and it was widely believed that they would remain low for the foreseeable future. In contrast, real O&M costs for nuclear power plants had increased by 77 percent during the 1980s [*71*], owners faced the risk that new NRC regulations might require prohibitively expensive retrofits, and there was widespread concern State public utility commissions would not allow full cost recovery for expenditures on nuclear plants.

The economics of existing nuclear power plants are more favorable today, because natural gas prices are higher, the nuclear plants are performing well, and the potential enactment of GHG regulations increases uncertainty about fuel and operating costs for power plants that burn coal and natural gas. To date, there have been no announced plans to retire any of the 104 operating U.S. commercial nuclear reactors. To the contrary, the NRC and the nuclear power industry are preparing applications for license renewals that would allow continued operation beyond 60 years, the first of which is scheduled to be submitted by 2013. In February 2008, DOE and the NRC hosted a joint workshop titled “Life Beyond 60,” with a broad group of nuclear industry stakeholders meeting to discuss this issue [*72*]. The workshop’s summary report outlined many of the technical research needs that participants agreed were important to extending the life of the existing fleet of U.S. nuclear plants.

Several concerns were expressed at the DOE/NRC workshop. Because heat, water, and radiation can have long-term effects on the materials they are in contact with in nuclear power plants, more effective monitoring may be needed as the systems age, which could require updates to instruments and controls. Over the next several years, research is being focused on identifying problems that aging facilities might encounter and formulating potential solutions. Until that research has been completed, it will be difficult to estimate any cost increases that may result from extending the age of reactors.

Future cost increases may reflect only routine expenditures, or they could involve major capital projects, such as the replacement of reactor vessels, containment structures, or buried piping and cables. To date, no plans or cost estimates for such potential modifications have been made public; however, they have the potential to be very expensive, and they could require extended plant shutdowns. While a plant is out of operation, the generation lost will have to be replaced, probably with expensive power purchased on the spot electricity market.

For most existing nuclear plants, decisions about retirement or life extension ultimately will be based on the cost and feasibility of all the measures needed for a plant to continue to operate safely and economically. It is difficult to anticipate future operating costs, but it can be helpful to compare current operating costs with the total levelized costs of new nuclear power plants in order to gauge the magnitude of increases in O&M costs that would make retirement an option from an economic standpoint. For instance, with current O&M costs at the most expensive nuclear units in operation averaging approximately 3.5 cents per kilowatthour [*73*] and total levelized costs for new baseload capacity ranging from 8 cents to 11 cents per kilowatthour, the operating costs of existing nuclear power plants would have to increase substantially before it would be economical to retire even the most expensive units.

Nuclear plant owners also face the risk of future regulations that could require expensive upgrades. Such a rule was recently the subject of the Supreme Court case *Entergy Corp v. Riverkeeper* [*74*], which focused on whether or not the EPA could conduct cost-benefit analyses to determine whether a plant needed to replace open-cycle cooling water systems with closed-cycle systems. A retrofit of such magnitude would be costly and thus could alter the relicensing decision for a particular facility.

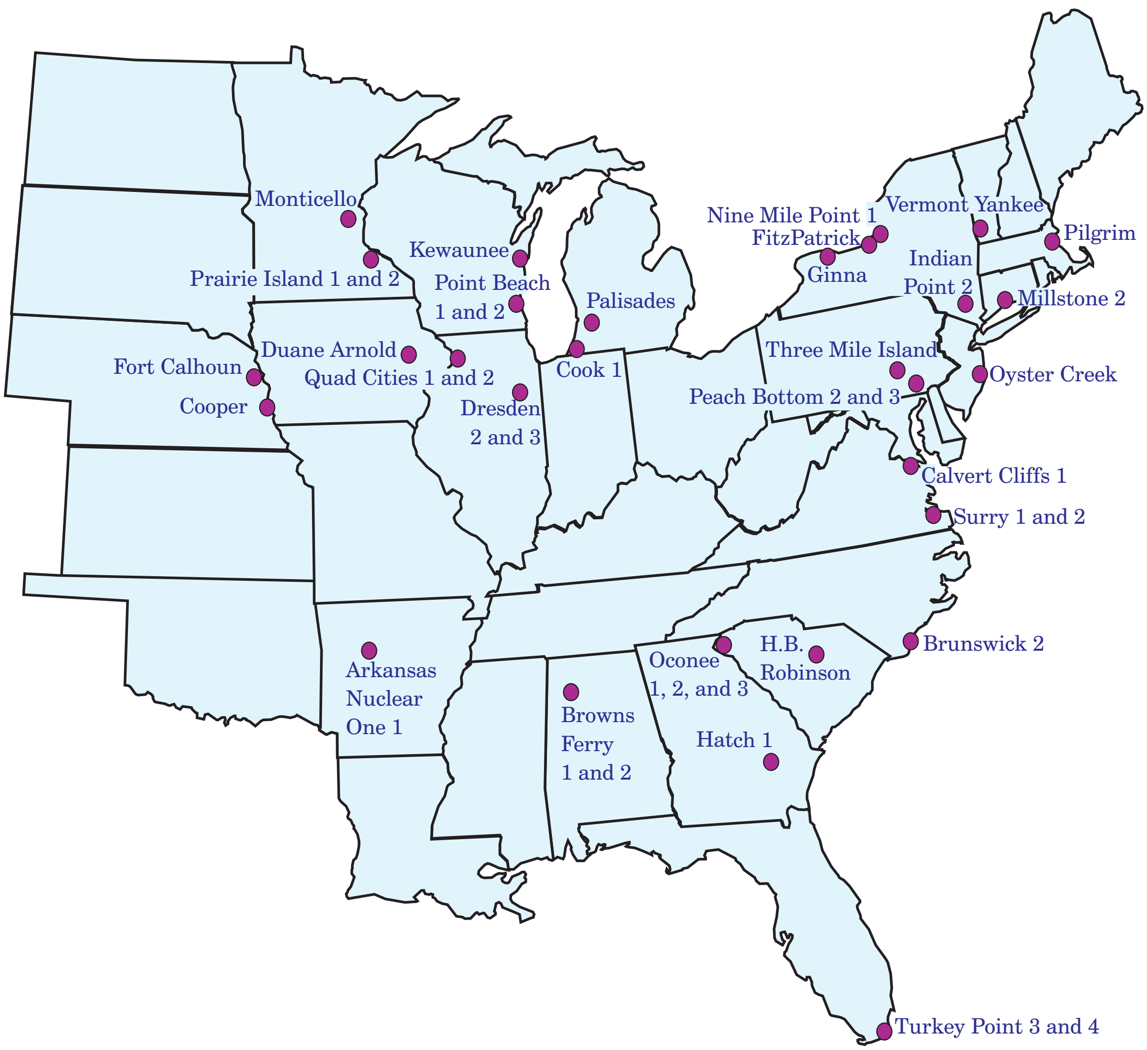
The *AEO2010* Reference case assumes an additional O&M cost of $30 per kilowatt for nuclear power capacity after 30 years of operation, which is meant to represent the various programs that must be undertaken in order to ensure continued safety. Even with this added cost, no retirements of existing nuclear power plants are projected by 2035 in the Reference case.

Alternative case

If all the existing nuclear power plants in the United States were retired after 60 years of operation, the impacts on electricity markets, fuel use, and GHG emissions would be substantial. Therefore, *AEO2010* includes an alternative Nuclear 60-Year Life case, which assumes that no existing nuclear power plant will receive a second license extension, and all of them will be retired after 60 years. The 60-year retirement assumption is not meant as a hard-and-fast rule but as a possibility that allows examination of the impact of retiring existing nuclear capacity from the generation mix.

A total of 30.8 gigawatts of capacity at operating U.S. nuclear power plants—or approximately one-third of the existing fleet—will have been in operation for at least 60 years by 2035. The Nuclear 60-Year Life case assumes that all of that capacity will be retired between 2029 and 2035. Figure 29 shows the locations of the plants that would be retired, which are spread fairly evenly across the regions where nuclear power capacity is prominent.

Figure 29. U.S. nuclear power plants that will reach 60 years of operation by 2035



In the Nuclear 60-Year Life case, retirement of the plants shown in Figure 29 results in the construction of additional replacement capacity beyond the capacity additions already projected in the Reference case (Table 8). Of the additional capacity built in the Nuclear 60-Year Life case, only about 2 gigawatts is nuclear. Instead, the retired nuclear capacity is replaced almost exclusively with coal and natural gas capacity, which in the absence of policies regulating GHG emissions remains more economical than either nuclear or renewable plants.

Reflecting the different projections for generating capacity additions in the two cases, the projected nuclear share of total generation in 2035 is only 13 percent in the Nuclear 60-Year Life case, compared with 17 percent in the Reference case. Total generation in the Nuclear 60-Year Life case is 1 percent lower than in the Reference case. CO_2 emissions are higher in the Nuclear 60-Year Life case, because nuclear power is replaced with fossil fuels. Again, however, the difference between the projections is less than 1 percent, because most of the capacity replacing the retired nuclear plants is fueled by natural gas.

U.S. electricity prices in 2035 in the Nuclear 60-Year Life case are 4 percent higher than those in the Reference case. In regions where the retirements are scheduled to occur, the price increases are slightly larger: compared to the Reference case, electricity prices in 2035 are 7 percent higher in the North American Electric Reliability Council (NERC) Midwest Reliability region and between 5 and 6 percent higher in the NERC regions in the Northeast, mid-Atlantic, and Southeast. In regions where no retirements occur, there are still small price increases relative to the Reference case, because natural gas prices are higher in the Nuclear 60-Year Life case. Building new capacity to replace the retired nuclear plants is more expensive than allowing their continued operation, and the higher costs are passed on to consumers in the form of higher electricity prices. Natural gas prices also are higher in the alternative case than in the Reference case, by 5.4 percent, because the additional new capacity is predominantly natural-gas-fired, and the increase in demand pushes up the price of natural gas.

Table 8. Comparison of key projections in the Reference and Nuclear 60-Year Life cases

Projection	Reference	Nuclear 60-Year Life
Generating capacity additions by fuel type, 2008-2035 (gigawatts)		
Coal	11	17
Natural gas	89	102
Nuclear	7	9
Renewable	57	57
Electricity price in 2035 (2008 cents per kilowatthour)	10.2	10.6
Natural gas price in 2035 (2008 dollars per thousand cubic feet)	8.69	9.16

Finally, the assumed absence of new Federal policies to limit GHG emissions is crucial to the results of this analysis. In all likelihood, such policies would increase the cost of generating electricity from fossil fuels, improving the relative economics of new nuclear power plants and favoring construction of more nuclear capacity to replace the retired units.

Accounting for carbon dioxide emissions from biomass energy combustion

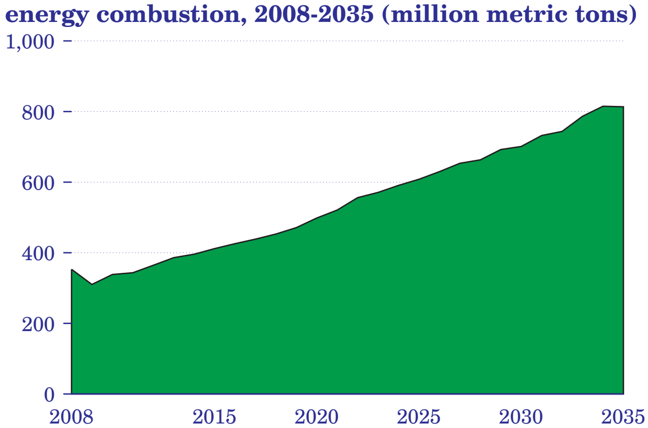
CO_2 emissions from the combustion of biomass [*75*] to produce energy are excluded from the energy-related CO_2 emissions reported in *AEO2010*. According to current international convention [*76*], carbon released through biomass combustion is excluded from reported *energy-related* emissions. The release of carbon from biomass combustion is assumed to be balanced by the uptake of carbon when the feedstock is grown, resulting in zero net emissions over some period of time [*77*]. However, analysts have debated whether increased use of biomass energy may result in a decline in terrestrial carbon stocks, leading to a net positive release of carbon rather than the zero net release assumed by its exclusion from reported energy-related emissions.

For example, the clearing of forests for biofuel crops could result in an initial release of carbon that is not fully recaptured in subsequent use of the land for agriculture. To capture the potential net emissions, the international convention for GHG inventories is to report biomass emissions in the category “agriculture, forestry, and other land use,” usually based on estimates of net changes in carbon stocks over time.

This indirect accounting of CO_2 emissions from biomass can potentially lead to confusion in accounting for and understanding the flow of CO_2 emissions within energy and non-energy systems. In recognition of this issue, reporting of CO_2 emissions from biomass combustion alongside other energy-related CO_2 emissions offers an alternative accounting treatment. It is important, however, to avoid misinterpreting emissions from fossil energy and biomass energy sources as necessarily additive. Instead, the combined total of direct CO_2 emissions from biomass and energy-related CO_2 emissions implicitly assumes that none of the carbon emitted was previously or subsequently reabsorbed in terrestrial sinks or that other emissions sources offset any such sequestration.

In the future, EIA plans to report CO_2 emissions from biomass combustion alongside other energy-related CO_2 emissions, but to exclude them from the total unless their inclusion is dictated by regulation. As shown in Figure 30, including direct CO_2 emissions from biomass energy combustion would increase the 2008 total for energy-related CO_2 emissions by 353 million metric tons (6.1 percent). In the *AEO2010* Reference case, including emissions from biomass would increase the projected 2035 total for energy-related CO_2 emissions by 813 million metric tons (12.9 percent) [*78*]. If in fact these emissions are all offset by biological sequestration, the net emissions would be zero as assumed in EIA's totals.

Figure 30. Carbon dioxide emissions from biomass energy combustion, 2008-2035 (million metric tons)



Endnotes for Issues in Focus

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40. "Oil Tops Obama's Saudi Agenda," *UpstreamOnline* (June 3, 2009); "Venezuelan President: Hugo Chavez Chavez Sets Sights on $80 Oil," *UpstreamOnline* (May 27, 2009); "OPEC 'Waiting on G20 Move'" *UpstreamOnline* (March 17, 2009) (subscription site).
41. "Upstream Costs Bottoming Out," *UpstreamOnline* (December 8, 2009) (subscription site).
42. "Upstream Players Face More Costs Pain," *UpstreamOnline* (May 14, 2008) (subscription site).
43. For a thorough discussion of the issues involved in measuring efficiency, see U.S. Energy Information Administration, *Measuring Energy Efficiency in the United States' Economy: A Beginning*, DOE/EIA-0555(95)/2 (Washington, DC, October 1995), web site www.eia.doe.gov/emeu/recs/archive/arch_hist_pubs/hp_pdf/DOE%20EIA-0555%2895%29-2.pdf; and S.J. Battles and E.M. Burns, "United States Energy Usage and Efficiency: Measuring Changes Over Time," Presented at the 17th Congress of the World Energy Council, Houston, TX (September 14, 1998), web site www.eia.doe.gov/emeu/efficiency/wec98.htm.
44. Energy efficiency and conservation are sometimes considered closely related aspects of the same concept, but the NEMS framework focuses on energy efficiency and classifies all other sources of intensity reduction as structural elements. The concepts are defined separately in NEMS so as not to overlap. For an alternative view, see K. Gillingham, R. Newell, and K. Palmer, "Energy Efficiency Economics and Policy," *Annual Review of Resource Economics*, Vol. 1 (2009), pp. 597–619.
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47. A. Jaffe and R. Stavins, "The Energy-Efficiency Gap," *Energy Policy*, Vol. 22, No. 10 (October 1994), pp. 804-810.
48. U.S. Department of Energy, Energy Efficiency and Renewable Energy, Alternative Fuels and Advanced Vehicles Data Center, "Alternative Fueling Station Total Counts by State and Fuel Type," web site www.afdc.energy.gov/afdc/fuels/stations_counts.html (updated on February 28, 2010).
49. The levelized cost calculation assumes that a 20-percent rate of return over a 5-year payback period would be sufficient to motivate investment in a standalone natural gas fueling station.
50. In the 2019 Phaseout Base Market case, HDNGV sales and consequent fuel switching are small enough to fall within the tolerance of the NEMS model used to produce *AEO2010* and are not reported.

51. Low-sulfur crude oil priced for delivery at Cushing, Oklahoma, and natural gas priced at the Henry Hub.
52. While simple price comparisons assume the same point of sale in retail markets, crude oil and natural gas price comparison reflects unprocessed prices at a supply node. To describe the ratio in terms of the retail market, multiple delivered petroleum product prices would have to be compared to delivered natural gas prices in the same markets. Because making the comparison at the detailed retail level would require a far more complex set of comparisons involving different tax structures and processing costs, the comparison on the supply side is a useful, if somewhat oversimplified, comparison that accounts for most of the price divergence described.
53. U.S. Energy Information Administration, *Annual Energy Review 2008*, DOE/EIA-0384(2008) (Washington, DC, June 2009), Table 8.4a, web site www.eia.doe.gov/emeu/aer.
54. U.S. Energy Information Administration, *Annual Energy Review 2008*, DOE/EIA-0384(2008) (Washington, DC, June 2009), Table 8.4a, web site www.eia.doe.gov/emeu/aer.
55. Consistent with that reduction has been the abandonment of large-scale storage by electric utilities of petroleum products for generation.
56. U.S. Energy Information Administration, *Assumptions to the Annual Energy Outlook 2010*, DOE/EIA-0554(2010) (Washington, DC, April 2010), p. 137, web site www.eia.doe.gov/oiaf/aeo/assumption/pdf/0554(2010).pdf, p. 137.
57. Favorable natural gas prices in the late 1990s led to a surge in investments in turbine and combined-cycle units, to a level that could not be supported when natural gas prices increased. Many of those purchases were resold at discounts, or installation was postponed for years.
58. J. Macharia, "Sasol Oryx GTL Plant Has Problems, Shares Hit," Reuters (May 22, 2007), web site www.reuters.com/article/idUSL2206595120070522.
59. Sasol I (2,500 barrels per day), Mossel Bay (45,000 barrels per day), Bintulu (14,700 barrels per day), and Oryx (34,000 barrels per day).
60. Qatar's Pearl GTL (140,000 barrels per day), which is currently anticipated to begin production in 2011, and Nigeria's Escravos GTL (34,000 barrels per day), which is also slated for a 2011 startup. See "Pearl GTL Sets Milestone as Steam Boilers Start Up," *Gulf Times* (not dated), web site www.gulf-times.com/site/topics/article.asp?cu_no=2&item_no=345533&version=1&template_id=48; and J. Macharia and M. Whittaker, "Update: 2-Sasol's Nigeria Project Costs Up, Loses on Oil Hedge," Reuters (July 29, 2008), web site http://uk.reuters.com/article/idUKL921344320080729.
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62. U.S. Energy Information Administration, *Assumptions to the Annual Energy Outlook 2010*, DOE/EIA-0554(2010) (Washington, DC, April 2010), p. 137, web site www.eia.doe.gov/oiaf/aeo/assumption/pdf/0554(2010).pdf, p. 137.
63. S. Reed and R. Tuttle, "Shell Aims for 'New Nigeria' as $19 Billion Qatar Plant Starts" *Bloomberg Business Week* (March 3, 2010), web site www.businessweek.com/news/2010-03-03/shell-aims-for-new-nigeria-as-19-billion-qatar-plant-starts.html.
64. Overnight capital costs exclude financing costs during construction.
65. A 10-year operating period is assumed as a maximum private-sector investment horizon for such a project. The 10-year period was chosen based on input from an EIA workshop held in 2007 that looked at capital investment decisionmaking. The papers resulting from that workshop can be found at www.eia.doe.gov/oiaf/emdworkshop/model_development.html. It is possible that a longer operating period would be appropriate with public financing or loan guarentees. This would have the effect of lowering the effective breakeven levels discussed in the article.
66. hydrocarbons-technology.com, "Pearl Gas-to-Liquids Project, Ras Laffan, Qatar" (not dated), web site www.hydrocarbons-technology.com/projects/pearl.
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75. "Biomass energy," as used here, includes solid, liquid, and gaseous energy produced from organic nonfossil material of biological origin.
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77. This is not to say that biomass energy is carbon-neutral. Energy inputs are required in order to grow, fertilize, and harvest the feedstock and to produce and process the biomass into fuels.
78. Emissions estimates are based on biogenic energy consumption (see Appendix A, Table A17, "Renewable Energy by Sector and Source") and CO_2 emissions factors of 88.45 kilograms CO_2 per million Btu for biomass (including wood, wood waste, and biofuels heat and coproducts), 90.65 kilograms CO_2 per million Btu for biogenic municipal solid waste, 65.88 kilograms CO_2 per million Btu for ethanol, 73.84 kilograms CO_2 per million Btu for biodiesel, and 73.15 kilograms CO_2 per million Btu for liquids from biomass and green liquids.

Market Trends

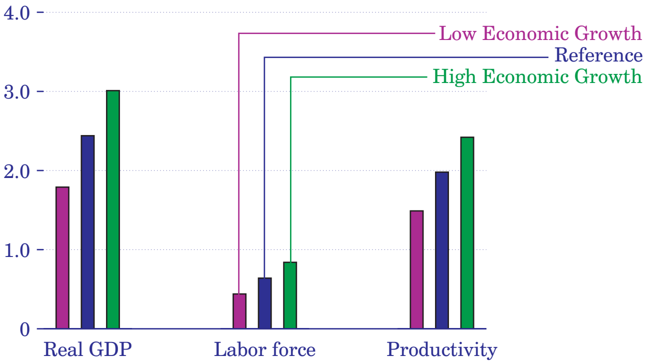
The projections in *AEO2010* are not statements of what will happen but of what might happen, given the assumptions and methodologies used. The projections are business-as-usual trend estimates, reflecting known technology and technological and demographic trends. *AEO2010* generally assumes that current laws and regulations are maintained throughout the projections. Thus, the projections provide a baseline starting point that can be used to analyze policy initiatives. However, EIA does not propose or advocate future legislative or regulatory changes.

While energy markets are complex, energy 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.

EIA has endeavored to make these projections as objective, reliable, and useful as possible; however, energy markets 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 *AEO2010* projections are addressed through alternative cases.

Real gross domestic product returns to its pre-recession level by 2011

Figure 31. Average annual growth rates of real GDP, labor force, and productivity in three cases, 2008-2035 (percent per year)



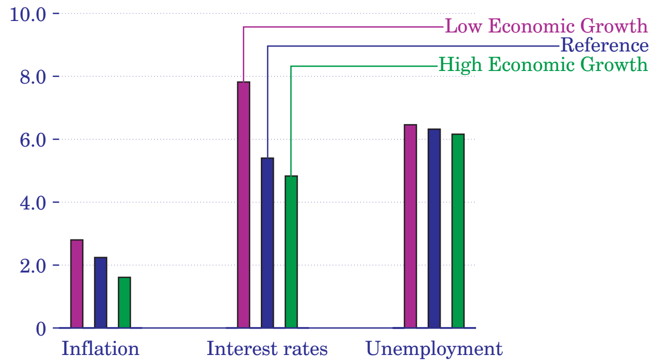
AEO2010 presents three views of economic growth (Figure 31). The rate of growth in real GDP depends on assumptions about labor force growth and productivity. In the Reference case, growth in real GDP averages 2.4 percent per year.

GDP growth is considerably slower in the near term as a result of the recent recession. The U.S. economy has seen 10 recessions since 1947 [*78*]. The 2007-2009 recession is projected to be the longest, with four consecutive quarters of negative growth, and also the deepest since 1957. In the *AEO2010* Reference case, economic recovery accelerates in 2011, while employment recovers more slowly. Real GDP returns to its pre-recessionary level by 2011, but unemployment rates do not return to pre-recessionary levels until 2019.

The *AEO2010* High and Low Economic Growth cases examine the impacts of alternative assumptions on the economy. The High Economic Growth case includes more rapid expansion of the labor force, nonfarm employment, and productivity, with real GDP growth averaging 3.0 percent per year from 2008 to 2035. With higher productivity gains and employment growth, inflation and interest rates are lower in the High Economic Growth case than in the Reference case. In the Low Economic Growth case, real GDP growth averages 1.8 percent per year from 2008 to 2035, with slower growth rates for the labor force, nonfarm employment, and labor productivity. Consequently, the Low Economic Growth case shows higher inflation and interest rates and slower growth in industrial output.

Inflation, interest rates remain low, unemployment exceeds 6 percent

Figure 32. Average annual inflation, interest, and unemployment rates in three cases, 2008-2035 (percent per year)



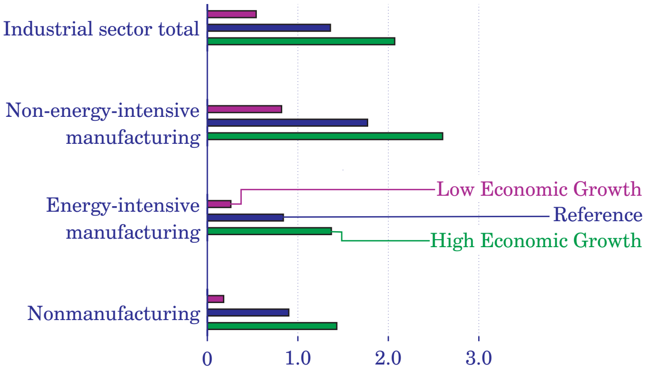
In the Reference case, annual consumer price inflation averages 2.2 percent, the annual yield on the 10-year Treasury note averages 5.4 percent, and the average unemployment rate is 6.3 percent (Figure 32). In the High Economic Growth case, population, technological change, and productivity grow faster than in the Reference case, leading to faster growth in capital stock, labor force, and employment. Potential output growth is faster, and as a result the real GDP annual growth rate is 0.5 percent higher than in the Reference case. In the Low Growth case, productivity, technological change, population, labor force, and capital stock grow more slowly, and real GDP growth is 0.5 percent lower than in the Reference case.

In the first 2 years of the Reference case projection, as the economy slowly recovers from the recession that began at the end of 2007, inflation and interest rates are below their 27-year projected averages of 2.2 and 5.4 percent, respectively, and unemployment rates are above their long-term average of 6.3 percent. The recession reduces household wealth, and unemployment remains high as people take longer than in past recessions to find employment. The unemployment rate returns to its 2007 rate of 5.8 percent in 2019. Annual gains in labor productivity average 2.0 percent, underpinning the projections for inflation and interest rates.

Energy prices for U.S. consumers grow by 2.4 percent per year from 2008 to 2035 in the Reference case, compared with 2.2-percent annual growth in overall consumer prices. For energy commodities, annual price increases average 2.5 percent per year.

Output growth for energy-intensive industries slows

Figure 33. Sectoral composition of industrial output growth rates in three cases, 2008-2035 (percent per year)



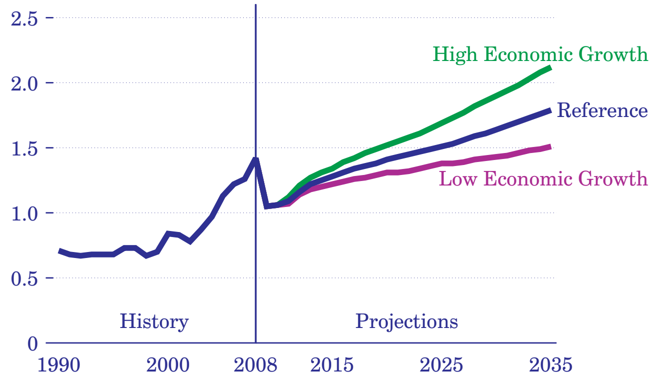
Industrial sector output has grown more slowly than the overall economy in recent decades, as imports have met a growing share of demand for industrial goods, whereas the service sector has grown more rapidly [*79*]. In the *AEO2010* Reference case, real GDP grows at an annual average rate of 2.4 percent from 2008 to 2035, while the industrial sector and its manufacturing component grow by 1.4 percent per year and 1.5 percent per year, respectively (Figure 33). With higher energy prices and greater foreign competition, the energy-intensive manufacturing sectors grow at a slower rate of 0.8 percent per year, which reflects a 0.6-percent annual decline for bulk chemicals and a 1.7-percent annual increase for food processing.

As the economy recovers from the recent recession, growth in U.S. manufacturing output in the Reference case accelerates from 2011 through 2020. After 2020, both GDP and manufacturing output return to growth rates closer to trend. Increased foreign competition, slow expansion of domestic production capacity, and higher energy prices increase competitive pressure on most manufacturing industries after 2020.

AEO2010 includes a range of possible economic outcomes resulting from different assumptions about growth in productivity, labor force, and population. Industrial output grows at annual average rates of 2.1 percent in the High Economic Growth case and 0.5 percent in the Low Economic Growth case.

Energy expenditures decline relative to Gross Domestic Product

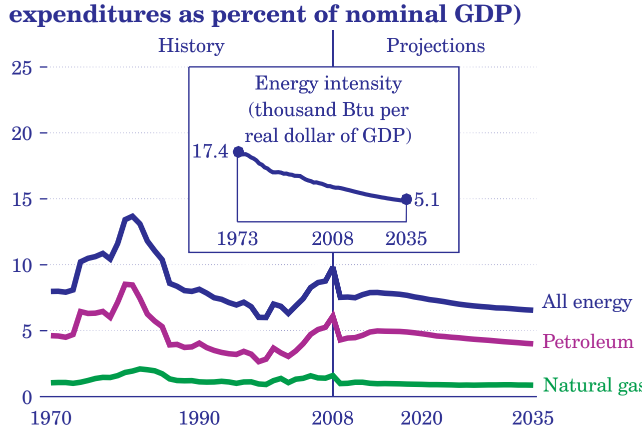
Figure 34. Energy expenditures in the U.S. economy in three cases, 1990-2035 (trillion 2008 dollars)



Total end-use expenditures for energy in the U.S. economy were $1.4 trillion in 2008. After falling in 2009, energy expenditures rise to $1.8 trillion (2008 dollars) in 2035 in the *AEO2010* Reference case, $2.1 trillion in the High Economic Growth case, and $1.5 trillion in the Low Economic Growth case (Figure 34). The energy intensity of the economy as a whole, measured as energy consumption (thousand Btu) per dollar of real GDP, was 8.6 in 2008. Structural shifts in the economy, improvements in energy efficiency, and rising world oil prices lead to a decline in U.S. energy intensity to 5.1 in 2035.

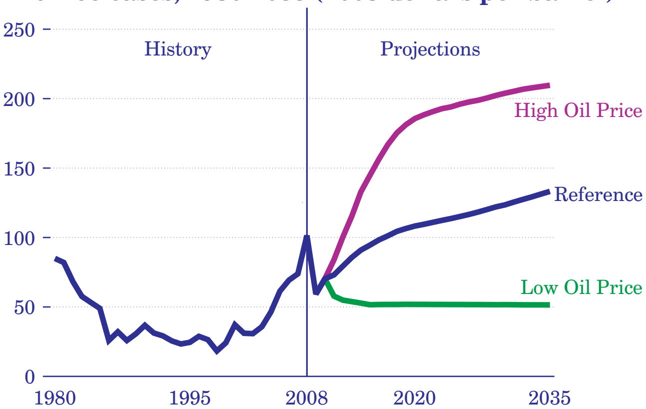
Since 2003, rising oil prices have pushed the share of energy expenditures as a percent of GDP upward; a 9.8-percent share in 2008 was the highest since 1986. In the *AEO2010* Reference case, as energy use becomes more efficient, its share declines to 6.5 percent of GDP by 2035 (Figure 35).

Figure 35. Energy end-use expenditures as a share of gross domestic product, 1970-2035 (nominal expenditures as percent of nominal GDP)



Oil price cases depict uncertainty in world oil markets

Figure 36. Average annual world oil prices in three cases, 1980-2035 (2008 dollars per barrel)



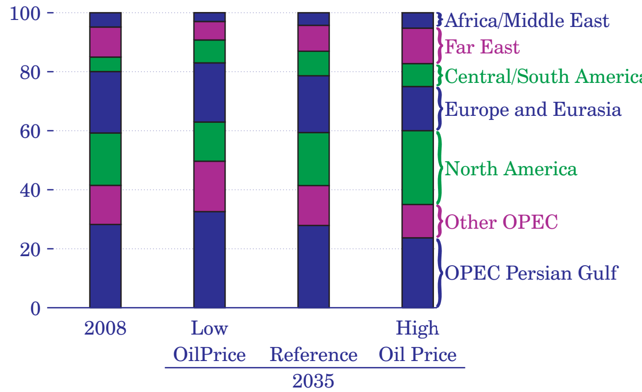
World oil price projections in *AEO2010*, defined in terms of the average price of low-sulfur, light crude oil delivered to Cushing, Oklahoma, span a broad range reflecting the inherent volatility and uncertainty of world oil prices (Figure 36). The *AEO2010* price paths are not intended to reflect absolute bounds for future oil prices, but rather to allow analysis of the implications of world oil market conditions that differ from those assumed in the Reference case. The *AEO2010* Reference case assumes a continuation of current trends in terms of economic access to non-OPEC resources and OPEC market share of world production.

The High Oil Price case depicts a future world oil market in which conventional production is restricted by political decisions and economic access to resources: use of quotas, fiscal regimes, and various degrees of access restrictions by the major producing countries decrease their oil production, and consuming countries turn to high-cost unconventional liquids production to satisfy demand. The OPEC share of liquids production is lower than in the Reference case.

The Low Oil Price case depicts a future world oil market in which non-OPEC producing countries develop stable fiscal policies and investment regimes directed at encouraging development of their resources. In the Low Price case, OPEC nations increase production in order to achieve approximately a 50-percent market share of total liquids production by 2035, up from approximately 42 percent in 2008.

World liquids supply remains geographically diversified

Figure 37. World liquids production shares by region in three cases, 2008 and 2035 (percent)



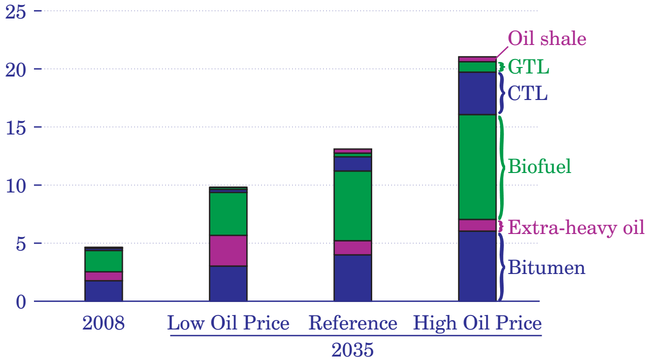
OPEC production decisions are the most significant factor underlying differences among the price cases. In the Reference case, OPEC conventional production maintains approximately a 40-percent share of total world liquids production through 2035, consistent with levels over the past 15 years. In the High Oil Price case, OPEC's share of world liquids production declines to 35 percent; in the Low Oil Price case, OPEC's share expands to almost 50 percent (Figure 37). In all the cases, total liquids production by countries in the Organization for Economic Cooperation and Development is between 21 and 27 million barrels per day in 2035, constrained mainly by resource availability rather than price or political concerns.

In the High Oil Price case, several non-OPEC countries with large resource holdings (including Russia, Brazil, Mexico, and Kazakhstan) either maintain or further restrict opportunities for investment in domestic resource development, limiting their contribution to the total world 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 recently either not encouraged such investment or indicated that they may enact future restrictions on foreign investment.

In the Low Oil Price case, several resource-rich nations outside OPEC, including Russia and Brazil, are assumed to change legislation or fiscal terms in order to encourage foreign investment in the development of their liquids resources. As a result, the largest increases in liquids supply among the non-OPEC countries occur in Russia, Brazil, and Kazakhstan.

Unconventional liquids gain market share as prices rise

Figure 38. Unconventional resources as a share of total world liquids production in three cases, 2008 and 2035 (percent)



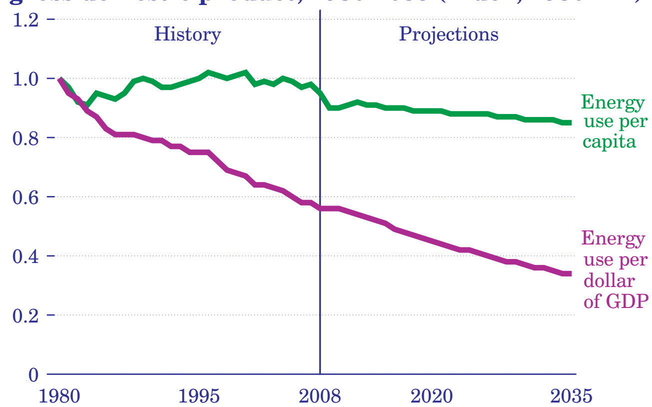
World production of liquid fuels from unconventional resources in 2008 was 4.0 million barrels per day, or about 5 percent of total liquids production. In the *AEO2010* projections, production from unconventional sources grows to about 13, 15, and 19 million barrels per day in 2035 in the Low Oil Price, Reference, and High Oil Price cases, respectively, accounting for about 10, 13, and 21 percent of total world liquids production (Figure 38).

The factors most likely to affect production levels vary for the different types of unconventional liquid. Price is the most important factor for bitumen production from Canadian oil sands, because the fiscal regime and extraction technologies remain relatively constant, regardless of world oil prices. Production of Venezuela's extra-heavy oil depends more on the prevailing investment environment and the assumed government-imposed levels of economic access to resources in the different price cases. In the Low Oil Price case, with more foreign investment in extra-heavy oil, production in 2035 climbs to nearly 3.4 million barrels per day. In the Reference and High Oil Price cases, with growing investment restrictions, extra-heavy oil production is limited to 1.3 and 0.8 million barrels per day, respectively, in 2035.

Production levels for biofuels, CTL, and GTL are driven 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 the Low Oil Price and High Oil Price cases, production from those three sources in 2035 totals 5.3 million barrels per day and 12.3 million barrels per day, respectively.

U.S. average energy use per person declines through 2035

Figure 39. Energy use per capita and per dollar of gross domestic product, 1980-2035 (index, 1980 = 1)

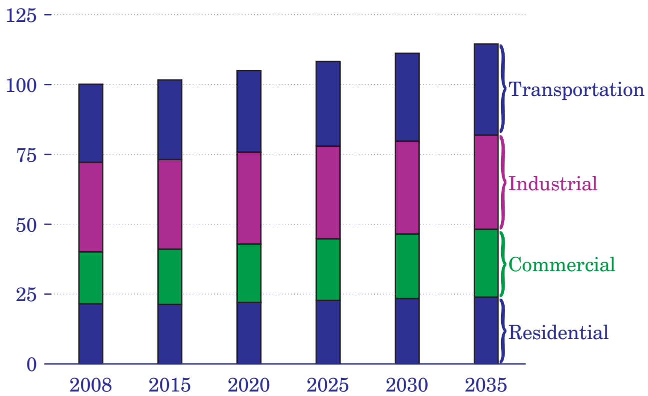


Growth in U.S. energy use is linked to population growth through increases in demand for housing, commercial floorspace, transportation, manufacturing, and services. This affects not only the level of energy use, but also the mix of fuels and consumption by sector. Energy consumption per person has declined sharply during the recent economic recession, and the 2009 level of 310 million Btu per person was the lowest since 1968. In the *AEO2010* Reference case, energy use per capita increases slightly as the economy rebounds, then begins declining in 2013 as higher efficiency standards for vehicles and lighting begin to take effect (Figure 39). From 2013 to 2035, energy use per capita declines by 0.3 percent per year on average, to 293 million Btu in 2035.

Energy intensity (Btu of energy use per dollar of real GDP) also falls as a result of structural changes and efficiency improvements. Since 1990, a growing share of U.S. output has come from services and less from manufacturing. In 1990, 74 percent of the total value of output came from services, 6 percent from energy-intensive manufacturing industries, and the balance from the non-energy-intensive manufacturing industries (e.g., agriculture, mining, and construction). In 2008, services accounted for 78 percent of total output and energy-intensive manufacturing only 5 percent. Services continue to play a growing role in the Reference case, accounting for 82 percent of total output in 2035, with energy-intensive manufacturing accounting for less than 4 percent. In combination with improvements in energy efficiency, the shift away from energy-intensive industries pushes overall energy intensity down by an average of 1.9 percent per year from 2008 to 2035.

Buildings and transportation sectors lead increases in primary energy use

Figure 40. Primary energy use by end-use sector, 2008-2035 (quadrillion Btu)



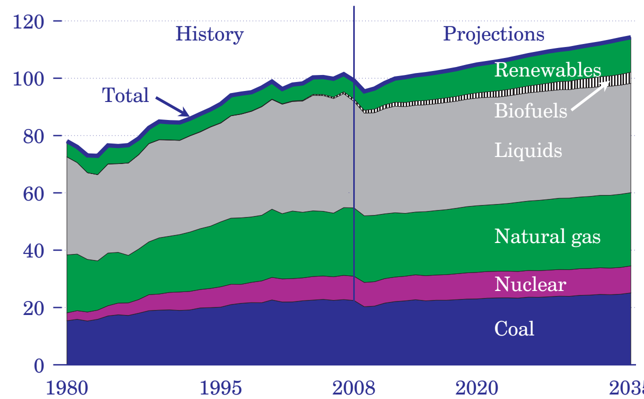
Total primary energy consumption, including fuels for electricity generation, grows by 0.5 percent per year from 2008 to 2035, to 114.5 quadrillion Btu in 2035 in the Reference case (Figure 40). The fastest growth (1.0 percent annually) is in the commercial sector, which currently has the smallest share of end-use energy demand but surpasses the residential sector by the end of the period. Growth in commercial sector energy use is propelled by growth in population (0.9 percent per year) and commercial floorspace (1.3 percent per year), but it is constrained somewhat by tightening efficiency standards.

Energy use for transportation grows by 0.6 percent per year in the Reference case. LDVs have accounted for more than 16 percent of total U.S. energy consumption since 2002; however, their share declines to 15.5 percent in 2020, when the average fuel economy of new LDVs is required by EISA2007 to reach 35.5 mpg. Growth in energy consumption by LDVs averages 0.4 percent per year from 2008 to 2035.

Energy consumption in the industrial sector grows only modestly through 2035, as U.S. output continues to shift toward less energy-intensive industries. Use of liquefied petroleum gas (LPG) feedstocks in the production of ethylene, propylene, and ammonia, which contributes to the small increase, declines after 2020 as output from the chemical industry falls. Energy consumption in the refining sector also grows, as liquids consumption increases and more biofuels are produced to meet the RFS required by EISA2007.

Renewable sources lead rise in primary energy consumption

Figure 41. Primary energy use by fuel, 1980-2035 (quadrillion Btu)



Consumption of all fuels increases in the Reference case, but the aggregate fossil fuel share of total energy use falls from 84 percent in 2008 to 78 percent in 2035 as renewable fuel use grows rapidly (Figure 41). The renewable share of total energy use increases from 8 percent in 2008 to 14 percent in 2035, in response to the EISA2007 RFS, expansion of Federal tax credits for renewable electricity generation and capacity, and State RPS programs.

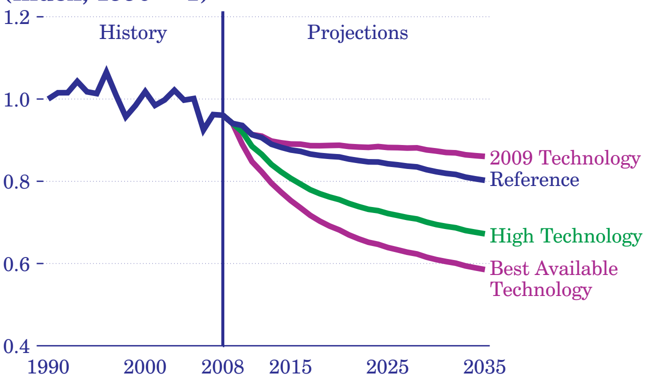
In the transportation sector, where almost all liquid biofuels are used, petroleum's share of liquid fuel use declines as consumption of alternative fuels (biodiesel, E85, and ethanol for blending) increases. Biofuels account for more than 80 percent of the growth in liquid fuel consumption.

Overall, natural gas consumption grows by about 0.2 percent per year from 2008 to 2035, despite declines of about 1.5 percent per year from 2008 through 2014, when coal-fired power plants now under construction or planned begin operation, and Federal tax credits and State RPS programs spur additions of new electricity generation capacity fired by renewable fuels.

Coal consumption increases by 0.4 percent per year in the Reference case. Several coal-fired power plants, with combined capacity totaling 15.6 gigawatts, are planned to come on line by 2012. More coal is consumed for heat and power in the CTL process, offsetting declines in coal consumption for coking and other industrial uses.

Residential energy use per capita varies with technology assumptions

Figure 42. Residential delivered energy consumption per capita in four cases, 1990-2035 (index, 1990 = 1)



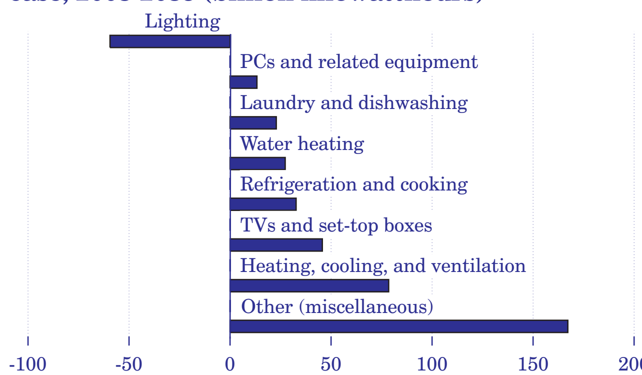
Residential energy use per capita continues declining in the *AEO2010* Reference case, to 16 percent below the 2008 level in 2035 (Figure 42). One cause of the decline is a decrease in energy use for space heating due to a projected shift in State populations from colder to warmer regions. The reduced demand for home heating fuels is offset in part by increased demand for electric air conditioning.

Recent improvements in household energy efficiency have been offset by growth in square footage and the introduction of new electric appliances. Three alternative cases show the potential role of energy-efficient technologies in defining household energy use. The 2009 Technology case assumes no change in efficiency for equipment or building shells beyond 2009 levels. The High Technology case assumes more purchases of energy-efficient appliances by consumers, and earlier availability, lower cost, and higher efficiency for some advanced electric devices. The Best Available Technology case limits purchases of new appliances to the most efficient available and assumes that new home construction applies the most energy-efficient criteria among today's common building practices.

In the 2009 Technology case, household energy use per capita falls by 10 percent from 2008 to 2035, as gains in energy efficiency are limited to stock turnover and more efficient new construction. With greater gains for appliances and building shells in the High Technology and Best Available Technology cases, household energy use per capita declines by 30 percent and 39 percent, respectively, from 2008 to 2035.

Miscellaneous uses dominate growth in electricity demand

Figure 43. Change in residential electricity consumption for selected end uses in the Reference case, 2008-2035 (billion kilowatthours)



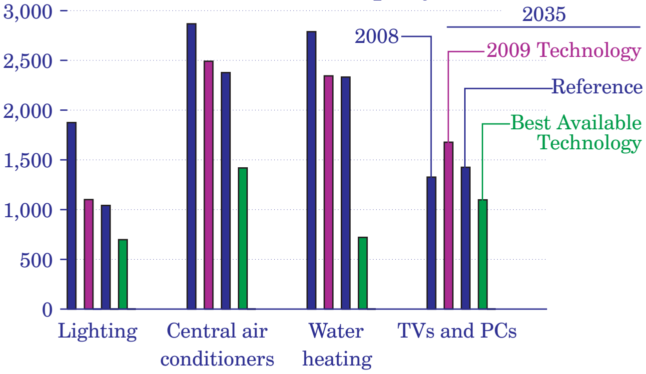
Electricity accounted for 41 percent of total residential delivered energy consumption in 2008, and in the *AEO2010* Reference case that portion increases to 48 percent in 2035. The increase in electricity consumption results from a proliferation of new electric devices. Comparatively few new devices powered by natural gas or liquids have emerged in recent decades, and few are anticipated in the Reference case. Electric appliances have become increasingly prevalent, and that trend continues as demand grows for large-screen televisions (TVs) and other electric devices.

Electricity use for TV sets and set-top boxes surpasses that for refrigerators in 2010. Set-top boxes, including digital video recorders, are needed to decode digital signals from cable or satellite providers and to convert digital signals for older analog TVs. TVs on the market today vary significantly with respect to power draw, depending on technology and screen size. The technology continues to evolve, and improvements in efficiency are expected with the introduction of light-emitting diode (LED) backlighting for TV screens and with new efficiency standards adopted in California.

Other electrically powered services include a range of appliances and devices whose consumption, while small individually, is significant in the aggregate (Figure 43). Electricity use for "other" devices—including microwave ovens, video and audio equipment, game systems, spas, security systems, and coffee makers—increases on average by 1.9 percent per year in the Reference case—slightly more than the 1.6-percent annual growth in residential floorspace.

New approaches to energy efficiency standards show potential for gains

Figure 44. Energy intensity for selected end uses of electricity in the residential sector in three cases, 2008 and 2035 (kilowatthours per year)



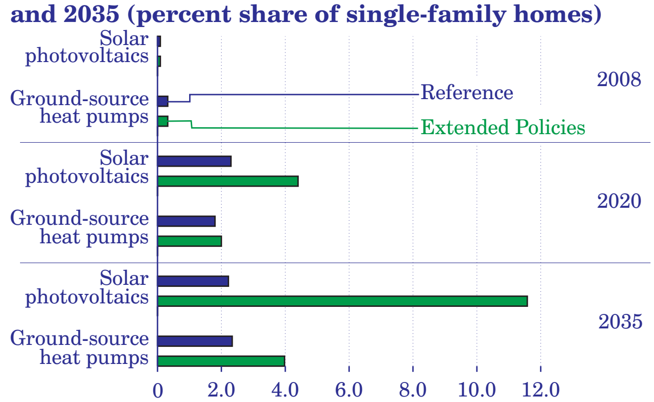
The energy efficiency of residential appliances plays a key role in determining the amount of energy used in buildings. In recent years, the implementation of Federal standards has fallen behind legislated schedules, leading States and other groups to become more active in promoting residential energy efficiency. In 2009, industry and efficiency advocate groups agreed on a set of regional standards to supplant the national standards currently in place. The new standards would divide the Nation into three regions based on climate characteristics for furnaces, heat pumps, and central air conditioners [*80*].

The absence of appliance standards has implications for energy use. Neither televisions nor set-top boxes are covered by Federal standards today, although some efficiency gains have been realized through voluntary programs, such as Energy Star. In the absence of standards, electricity use for personal computers and related equipment (e.g., printers, modems, and routers) grows at roughly the same rate as population in the Reference case.

The potential effects of new efficiency standards are most evident for lighting (Figure 44). Federal standards included in EISA2007 will require general-service lighting to use about 30 percent less electricity by 2014 for the same level of light output. In 2020, the standard is tightened further, requiring general-service lighting to use 60 percent less electricity than today's incandescent bulbs. Overall, in the *AEO2010* Reference case, electricity use for lighting per household in 2035 is 44 percent lower than in 2008.

Tax credits encourage installation of renewable technologies

Figure 45. Residential market saturation by renewable technologies in two cases, 2008, 2020, and 2035 (percent share of single-family homes)



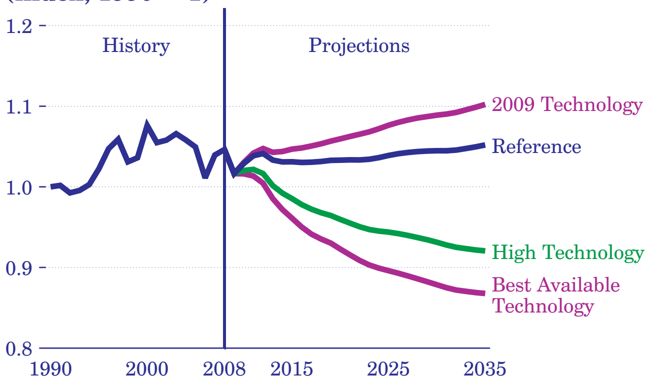
More than one-half of the States have either binding RPS or nonbinding voluntary targets for renewable energy generation. The recent enactment of Federal ITCs for distributed renewable technologies through 2016 provides the greater assurance necessary for market development that will help States achieve their renewable energy goals.

The *AEO2010* Reference case assumes that Federal tax credits for distributed renewable technologies will expire as scheduled. The Extended Policies case shows the implications of extending the tax credits indefinitely. Whereas total installed PV capacity reaches 9.5 gigawatts in 2035 in the Reference case, it grows to 60.5 gigawatts in 2035 in the Extended Policies case. The comparatively smaller distributed wind turbine market is similarly affected, with 8.1 gigawatts installed in the Extended Policies case, as compared with 1.7 gigawatts in the Reference case, in 2035.

Ground-source heat pumps are more energy efficient—but also more expensive—than conventional technologies. In the Reference case, implementation of current incentives increases the number of installations from 47,000 units in 2008 to an average of more than 150,000 units per year through 2016, when the Federal tax credit expires. Even with the increase in installations, however, the market share of ground-source heat pumps is only 2.3 percent in 2035 in the Reference case, up from 0.3 percent in 2008 (Figure 45). In the Extended Policies case—with the tax credit extended through 2035—the market share nearly doubles, to 4 percent in 2035.

Efficiency improvements could lower projected consumption growth

Figure 46. Commercial delivered energy consumption per capita in four cases, 1990-2035 (index, 1990 = 1)

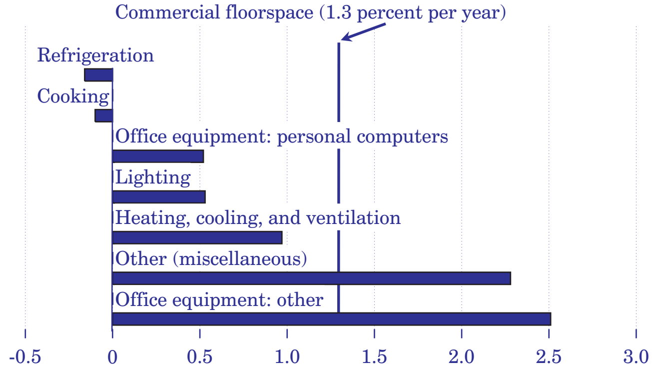


Growth in commercial floorspace averages 1.3 percent per year from 2008 to 2035 in the *AEO2010* Reference case, exceeding the 0.9-percent average for population growth over the period. Delivered commercial energy use per person remains virtually constant, however, as efficiency improvements largely offset the increase in commercial floorspace (Figure 46). Recently updated standards for lighting and refrigeration account for much of the efficiency improvement. More stringent building codes in ARRA further improve building efficiency in the long term.

Three alternative cases show the effects of different assumptions about technology and energy efficiency on energy consumption per capita. The 2009 Technology case limits equipment and building shell technologies to the options available in 2009. The High Technology case assumes lower costs, higher efficiencies for equipment and building shells, and earlier availability of some advanced equipment than in the Reference case, as consumers place greater importance on the value of future energy savings. The Best Available Technology case assumes more improvement in the efficiency of building shells than in the High Technology case and limits future equipment choices to a technology menu that includes only the most efficient model for each type of technology available in a particular year, regardless of cost. In 2035, commercial energy consumption per capita is 4.8 percent higher in the 2009 Technology case than in the Reference case, and in the High Technology and Best Available Technology cases it is 12.5 percent and 17.5 percent lower than in the Reference case, respectively.

Electricity leads expected growth in commercial energy use

Figure 47. Average annual growth rates for selected electricity end uses in the commercial sector, 2008-2035 (percent per year)



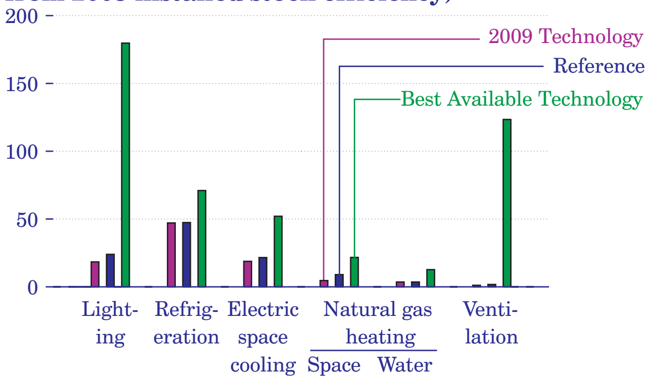
Purchased electricity use accounts for 59 percent of all commercial delivered energy consumption in 2035 in the Reference case, up from 54 percent in 2008. Despite growth in natural gas use for CHP, the natural gas and liquids share of commercial energy use declines as the efficiency of building and equipment stocks improves and demand for new electronic equipment continues to grow.

Major commercial end uses, such as space heating and cooling, water heating, and lighting, are covered by Federal and State efficiency standards, limiting growth in consumption to rates less than the 1.3-percent annual growth in commercial floorspace (Figure 47). Other electric end uses, some of which are not subject to Federal standards, account for most of the growth in commercial electricity consumption.

Although the number of computers and related devices (such as monitors and printers) grows more rapidly than floorspace, with increasing purchases and use of Energy Star equipment their electricity use grows at less than half the rate of floorspace. As reliance on the Internet for information and data transfer increases, electricity use for "other" office equipment—including servers and mainframe computers—surpasses that for commercial refrigeration in 2018. Refrigeration is one of the few commercial end uses for which electricity use declines in the Reference case, primarily as a result of new efficiency standards. Electricity demand for other miscellaneous end uses (e.g., video displays and medical devices) increases by an average of 2.3 percent per year and, in 2035, accounts for 40 percent of end-use electricity consumption in the commercial sector.

Technology provides potential energy savings in the commercial sector

Figure 48. Efficiency gains for selected commercial equipment in three cases, 2035 (percent change from 2008 installed stock efficiency)



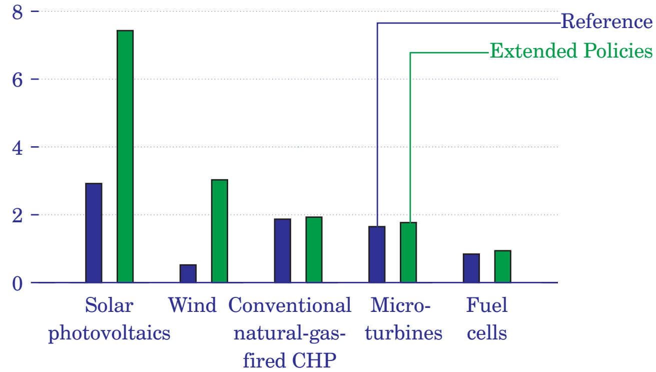
Delivered energy consumption for space heating, cooling, and water heating grows at an average annual rate of 0.4 percent in the Reference case, as compared with 1.3-percent annual growth in commercial floorspace. The remaining end uses in the commercial sector grow by 1.2 percent per year as a group in the Reference case, but by only 0.5 percent in the Best Available Technology case.

Lighting improvements have consistently been a source of efficiency gains, as standards for fluorescent lamps and ballasts, incandescent reflector lamps, and metal halide lamp fixtures have reduced their electricity consumption. Incandescent bulbs, which already are less common in the commercial sector, are nearly eliminated by 2014 as compliance with EISA2007 lighting standards increases. Significant potential for further improvement remains, as shown by the Best Available Technology case (Figure 48); however, many of those best available technologies, such as LED lighting, currently are too costly to be practical in many commercial applications.

The energy efficiency of refrigeration equipment improves significantly in each of the cases, as a result of EPACT2005 and EISA2007 standards, which are in place for a wide range of commercial equipment that accounts for a significant share of the sector's total electricity use for refrigeration. Additional efficiency improvements could come from the actions of States applying their own equipment standards for end uses not covered by Federal mandates. In addition, at the Federal level, new research and development funding from ARRA may lead to efficiency improvements in communication and information technology devices.

Tax credits, advanced technologies could boost distributed generation

Figure 49. Additions to electricity generation capacity in the commercial sector in two cases, 2008-2035 (gigawatts)



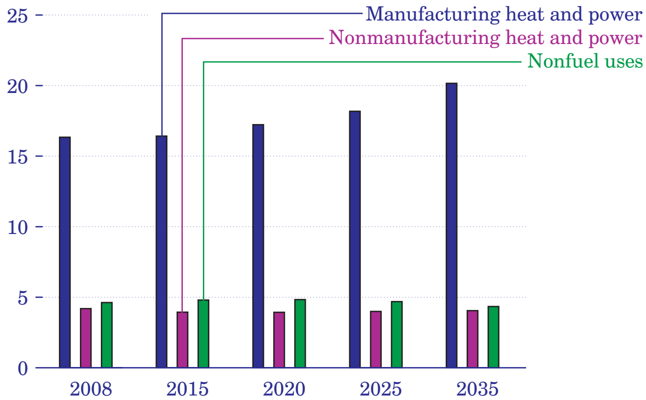
Recent legislation has extended or increased the ITCs for distributed generation technologies and removed the cap on credits for wind-powered generation. In the Reference case, tax credits boost the near-term expansion of distributed generation in the commercial sector, and its growth remains strong in later years as technology costs decline, conversion efficiency improves, and electricity prices increase.

PV capacity benefits from a 30-percent ITC through 2016 and reverts to a 10-percent credit thereafter (Figure 49). Conventional natural-gas-fired turbines and engines account for the next-largest capacity increase, followed by microturbines and fuel cells. Wind power also benefits from the ITC, growing by 8.7 percent per year. Conventional CHP technology receives a 10-percent tax credit through 2016. Comparatively expensive fuel cells receive a 30-percent ITC capped at $3,000 per kilowatt.

In the Reference case, commercial distributed generating capacity grows from 2 gigawatts in 2008 to almost 10 gigawatts in 2035. In the Extended Policies case, which assumes that the ITC provisions are extended through 2035, total commercial generating capacity increases by 17 gigawatts. PV technology benefits the most from the extension of the ITC provisions in the Extended Policies case, with installed capacity in 2035 that is 125 percent higher than in the Reference case. After 2016, with the extension of the ITC, wind power capacity in the commercial sector grows the fastest, averaging more than 16 percent per year from 2016 to 2035.

Heat and power energy consumption increases in manufacturing industries

Figure 50. Industrial delivered energy consumption by application, 2008-2035 (quadrillion Btu)



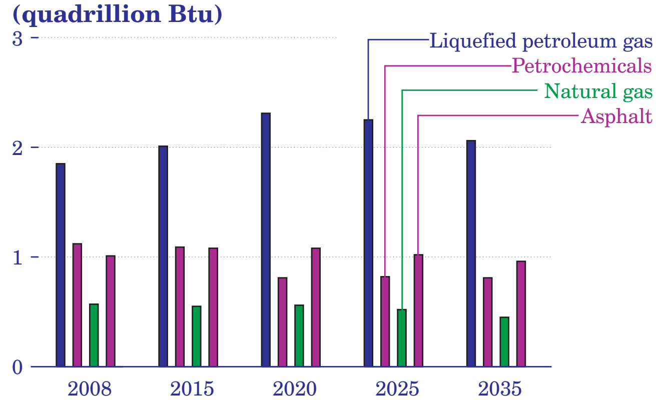
Industrial delivered energy consumption increases by 8 percent from 2008 to 2035 in the *AEO2010* Reference case—despite a 44-percent increase in industrial shipments—as a result of slow growth or declines in energy-intensive manufacturing output and strong growth in high-value (but less energy-intensive) industries, such as computers and electronics. In the chemical industry, output declines by nearly 10 percent from 2008 to 2035 in the face of rising energy prices and pressure from overseas competition.

In 2008, about two-thirds of delivered energy consumption in the industrial sector was used for heat and power in manufacturing; that share increases to three-quarters in 2035 (Figure 50). Heat and power consumption in the nonmanufacturing industries (agriculture, mining, and construction) remains constant over the projection, accounting for about one-sixth of total industrial energy consumption. The remaining consumption consists of nonfuel uses of energy products, primarily as feedstocks in chemical manufacturing and asphalt for construction.

The rise in manufacturing heat and power consumption in the *AEO2010* Reference case can be attributed primarily to a relatively large 36-percent increase in total energy use for the refining industry (although the value of shipments produced by the refining industry grows by only 11 percent over the same period). The strong growth in fuel use for refining results from higher industrial demand for lighter feedstocks, changes in the production mix as demand for diesel fuels increases, a shift by refineries from lighter to heavier crude oils, and growth in biofuels production.

Use of fuels as feedstocks declines in the chemical industry

Figure 51. Industrial consumption of fuels for use as feedstocks by fuel type, 2008-2035 (quadrillion Btu)



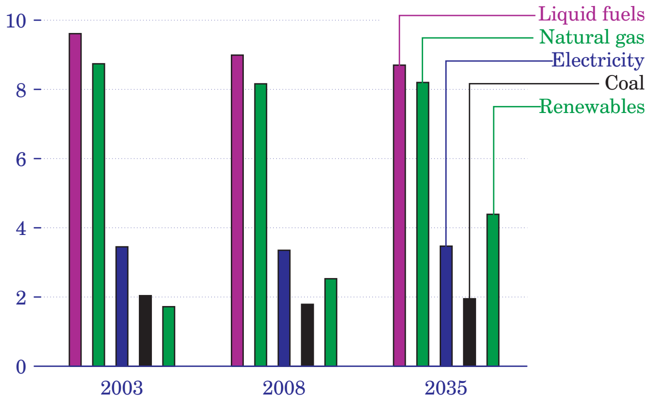
The use of fuels for feedstock in the industrial sector involves the consumption of fuels as raw materials for the production of various chemicals, as well as the consumption of asphalt and road oil for the building of roads in the construction industry. Most of the consumption of fuel-based feedstocks occurs in the chemical industry, primarily for the production of ethylene, propylene, and butadiene—three chemicals that are basic to the production of a variety of plastic products.

Feedstock consumption trends in the *AEO2010* Reference case reflect a switch from petrochemical feedstocks (naphtha and gas oils) to LPG feedstocks (ethane, butane, and propane) and a decline in basic chemical production. The shift occurs because of a growing divergence between more rapidly rising crude oil prices, which are the basis for petrochemical feedstock prices, and the slow pace of increase in natural gas prices—the primary basis for LPG prices.

From 2008 to 2035, total energy use as a feedstock declines by 6 percent in the industrial sector (Figure 51). Virtually all the decline is in the use of natural gas feedstocks, which drops by 21 percent as domestic production of ammonia, hydrogen, and methanol slows. Domestic ammonia production falls by 6 percent as a result of slow growth in agricultural production and foreign competition in the ammonia industry. Domestic outputs of hydrogen and methanol decline even more, by 74 percent and 32 percent, respectively. Consumption of asphalt and road oil remains flat in the Reference case, reflecting slow growth in the construction industry.

Over time, more fuels are brought into the mix of industrial energy use

Figure 52. Industrial energy consumption by fuel, 2003, 2008, and 2035 (quadrillion Btu)



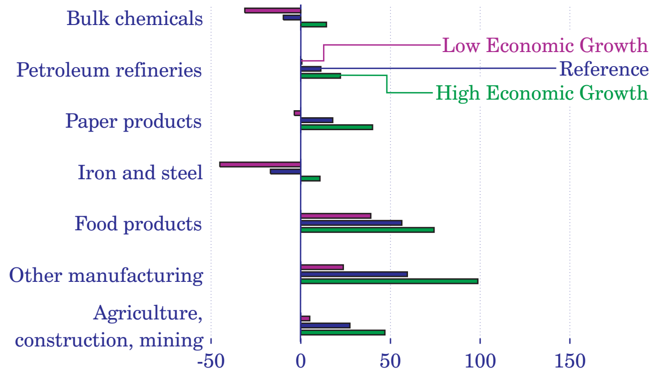
Liquid fuels and natural gas currently account for about two-thirds of industrial delivered energy use, and electricity, coal, and renewables make up the remainder (Figure 52). With fuel-switching opportunities often limited to boilers, kilns, and some feedstocks, changes in fuel shares tend to reflect long-term transitions among the mix of industries and capital investment. Although their use is declining, liquid fuels and natural gas are the leading industrial fuel sources throughout the projections. Almost one-half of industrial liquid fuel consumption is for use as a feedstock for the production of petrochemicals. Another large portion (28 percent) is generated as by-product fuel and consumed at refineries. The decline in industrial use of liquid fuels and natural gas reflects a drop in chemical production, which accounted for a large share of industrial use of the two fuels (excluding natural gas lease and plant fuel) in 2008.

Increased coal use for CTL production more than offsets a decline in traditional industrial applications of coal, such as steam generation and coke production, largely because of environmental concerns about emissions from coal-fired boilers, along with improvements in manufacturing efficiency that reduce the need for process steam. Metallurgical coal use also declines, reflecting a decline in steel industry output and the greater penetration of electric arc furnaces.

The flat outlook for industrial electricity use reflects efficiency gains in many industries, due in part to motor efficiency standards. In addition, consumption of renewable energy in the industrial sector expands with expected growth in the lumber, paper, and other industries that consume biomass-based byproducts.

Output growth is strongest for food and non-energy-intensive industries

Figure 53. Cumulative growth in value of shipments by industrial subsector in three cases, 2008-2035 (percent)



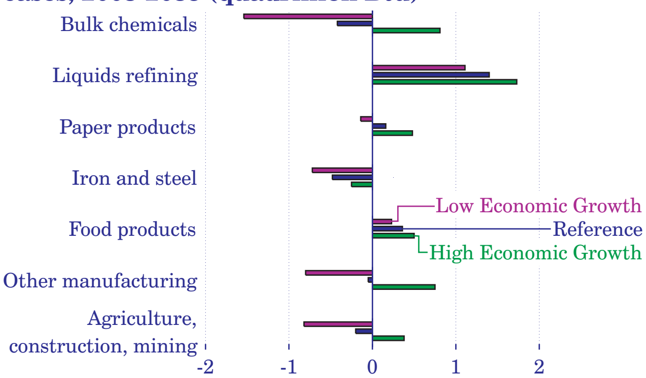
Industrial shipments vary across the *AEO2010* economic growth cases, both in aggregate and by industry. Total industrial shipments grow by 44 percent from 2008 to 2035 in the Reference case, as compared with 16 percent in the Low Economic Growth case and 74 percent in the High Economic Growth case. Near-term industrial activity is slowed by the economic recession, however, with shipments from 2008 to 2011 lower for most industries and in particular for iron and steel, cement, aluminum, transportation equipment, and machinery.

A few energy-intensive manufacturing industries account for a large share of total industrial energy consumption. Ranked by their 2008 total energy use, the top five energy-consuming industries—bulk chemicals, refining, paper, steel, and food—accounted for about 60 percent of total industrial energy consumption but only 22 percent of total value of shipments. From 2008 to 2035, four of those top five industries (with food products being the exception), as well as the other energy-intensive industries (glass, cement, and aluminum) grow more slowly than the non-energy-intensive industries (Figure 53).

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 of the economy.

Energy consumption growth varies widely across industry sectors

Figure 54. Change in delivered energy consumption for industrial subsectors in three cases, 2008-2035 (quadrillion Btu)



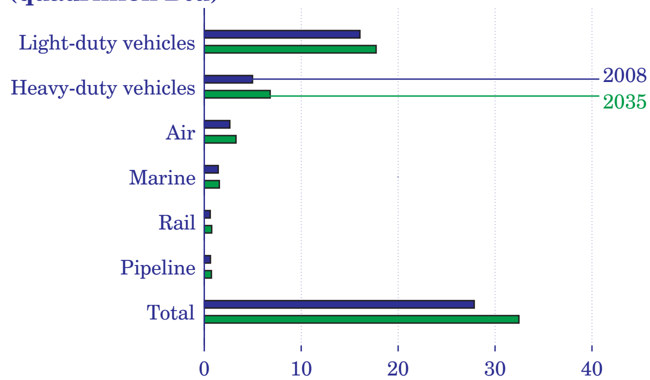
The projections for industrial energy consumption vary by industry (Figure 54) and are subject to considerable uncertainty. Industrial delivered energy consumption grows by 8 percent from 2008 to 2035 in the Reference case, declines by 9 percent in the Low Economic Growth case, and increases by 25 percent in the High Economic Growth case.

In absolute terms, the most significant changes in energy use are in the three largest energy-consuming industries: bulk chemicals, iron and steel, and refining. For the first two, declines in energy use in most cases reflect changes in competition from countries with access to less expensive energy sources, as well as changes in product mix. Energy consumption in the refining industry *increases*—despite a relatively flat trend in overall petroleum demand—given the industry's needs to process heavier crude oils, comply with low-sulfur fuel standards, and produce biofuels as mandated in EISA2007. Energy use also increases in the food and paper and pulp industries, where rising shipments reverse recent declines. For the cement, aluminum, and "other nonmanufacturing" industries, delivered energy consumption declines, primarily as a result of relatively slow output growth and long-term changes in production technology.

Aggregate industrial energy intensity, or consumption per real dollar of shipments, declines in all three cases. When a higher rate of economic growth is assumed the decline is more rapid, because non-energy-intensive output grows relatively more rapidly: 1.4 percent in the High Economic Growth case, as compared with 1.2 percent in the Reference case and 1.0 percent in the Low Economic Growth case.

Growth in transportation energy use slows relative to historical trend

Figure 55. Delivered energy consumption for transportation by mode, 2008 and 2035 (quadrillion Btu)



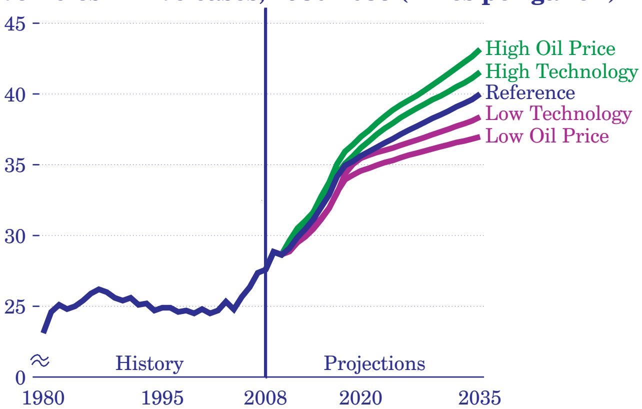
From 2008 to 2035, transportation sector energy consumption grows at an average annual rate of 0.6 percent (from 27.9 quadrillion Btu to 32.5 quadrillion Btu), slower than the 1.3-percent average rate from 1980 to 2008. The slower growth is a result of changing demographics, improved fuel economy, and increased saturation of personal travel demand.

Energy demand for LDVs increases by 10 percent, or 1.7 quadrillion Btu (0.8 million barrels per day), from 16.7 quadrillion Btu in 2008 (Figure 55). Slower growth in fuel prices compared with recent history and rising real disposable income combine to increase annual VMT. Delivered energy consumption by LDVs is tempered by fuel economy improvements that result from more stringent standards for vehicle fuel economy and CO_2 emissions. Energy demand for heavy-duty vehicles (including freight trucks and buses) increases by 37 percent, as a result of only slow improvement in fuel economy and modest increases in industrial output.

Energy demand for air travel increases by 24 percent, or 0.6 quadrillion Btu (0.3 million barrels per day), from 2.6 quadrillion Btu in 2008. Growth in personal air travel is driven by increases in income per capita and relatively low fuel costs; however, gains in aircraft fuel efficiency and slow growth in air freight movement (caused by slow growth in imports) combine to slow the increase in fuel use by aircraft. Energy consumption for marine and rail travel increases slightly as industrial output rises and demand for coal transport grows. Energy use for pipelines increases as growing volumes of natural gas and biofuels are transported.

New CAFE and emissions standards boost vehicle fuel efficiency

Figure 56. Average fuel economy of new light-duty vehicles in five cases, 1980-2035 (miles per gallon)



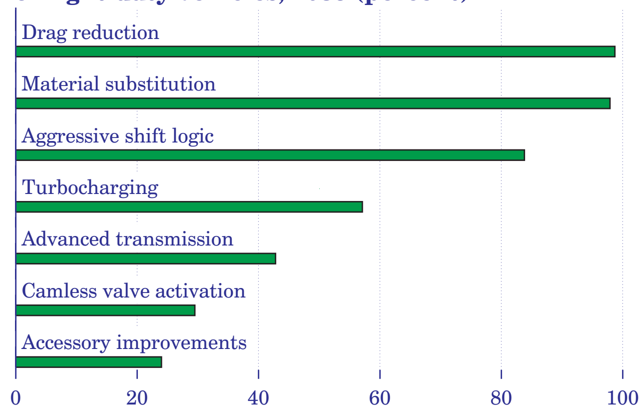
Light trucks (pickups, SUVs, and vans) have claimed a rising share of U.S. LDV sales since the 1970s, peaking at over 55 percent of new LDV sales in 2004 before dropping to just over 47 percent in 2009 [*81*]. Thus, despite technology improvements, average fuel economy for new LDVs ranged between 24 and 26 mpg from 1995 to 2006 after peaking at 26.2 mpg in 1987, then rose to 26.6 mpg in 2007 with higher fuel prices and introduction of tighter fuel economy standards.

NHTSA and EPA have proposed attribute-based CAFE and emissions standards for MY 2012 to 2016. In the Reference case, the average fuel economy of new LDVs (including credits for AFVs and banked credits) rises from 29 mpg in 2011 to 34 mpg in 2016 and 35.6 mpg in 2020, averaging 3.1 percent per year from 2011 to 2016 and 1.2 percent per year from 2016 to 2020 (Figure 56). EISA2007 requires an average of 35 mpg in 2020.

LDV sales in 2035 are about 19 million units in all the *AEO2010* cases, but the mix of cars and light trucks varies. In the Reference case, cars represent 66 percent of sales in 2035, and LDV fuel economy averages 40 mpg. In the High Oil Price case, cars are 69 percent of sales in 2035, and LDV fuel economy averages 43 mpg. In the Low Oil Price case, cars are 57 percent of sales in 2035, and LDV fuel economy averages 37 mpg. Economics of fuel-saving technologies improve in the High Technology and High Oil Price cases, and consumers buy more efficient vehicles. But average fuel economy improves modestly, because the CAFE standards assumed in the two cases already require significant improvement in fuel economy performance and the penetration of advanced technologies.

New technologies promise better vehicle fuel efficiency

Figure 57. Market penetration of new technologies for light-duty vehicles, 2035 (percent)



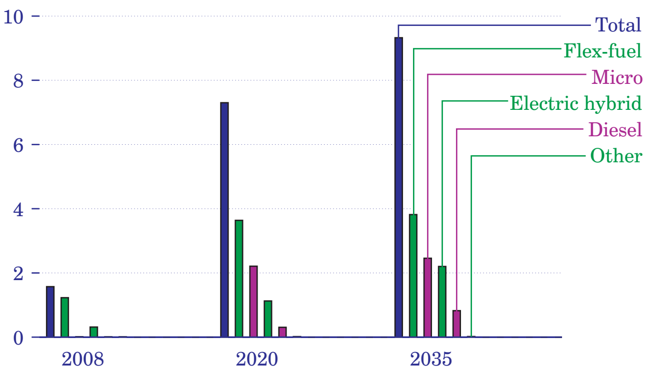
In the *AEO2010* Reference case, the fuel economy of new LDVs improves from 27.6 mpg in 2008 to 40.0 mpg in 2035. Market adoption of advanced technologies facilitates the improvement in fuel economy that will be needed to meet new, more stringent CAFE standards (Figure 57).

In 2035, advanced drag reduction, which provides significant fuel economy improvements by reducing vehicle air resistance at higher speeds, is implemented in nearly 99 percent of new LDVs. With the adoption of light-weight materials that reduce vehicle mass, the average weight of new cars declines from 3,264 pounds in 2008 to 3,112 pounds in 2035, providing significant improvements in fuel economy. In addition, adoption of advanced transmission technologies, such as continuous variable and automated manual transmissions, grows from 5 percent of the LDV market in 2008 to 43 percent in 2035.

Camless valve activation, which reduces engine friction and allows for infinitely variable valve timing and lift, increases engine efficiency by approximately 14 percent. After its introduction in 2020, camless valve activation is implemented in 30 percent of the LDVs marketed by 2035. Other technologies that improve fuel economy—including turbocharging, supercharging, and cylinder deactivation—increase from a 5-percent share of new LDV sales in 2008 to 57 percent in 2035. Improvements in accessories, such as the replacement of mechanical pumps with electric pumps that increase fuel economy by up to 1.5 percent, are implemented in 24 percent of new LDV sales in 2035, as compared with 0.1 percent of new LDV sales in 2008.

Unconventional vehicle technologies approach 50 percent of sales in 2035

Figure 58. Sales of unconventional light-duty vehicles by fuel type, 2008, 2020, and 2035 (million vehicles sold)



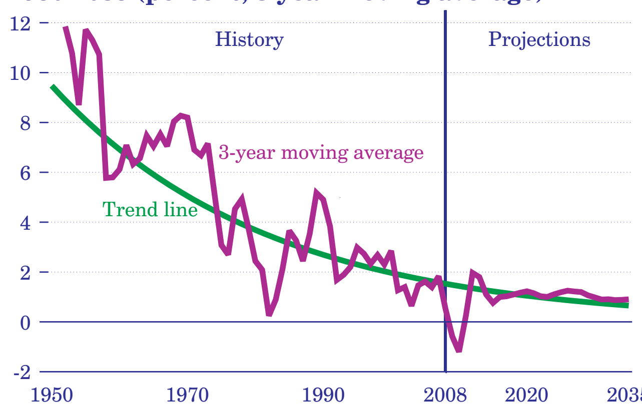
With more stringent CAFE standards and higher fuel prices, unconventional vehicles (vehicles that use alternative fuels, electric motors and advanced electricity storage, advanced engine controls, or other new technologies) account for nearly 50 percent of new LDV sales in 2035 in the Reference case. Unconventional vehicle technologies play a significant role in meeting the new NHTSA CAFE standards for LDVs.

FFVs represent 41 percent of unconventional LDV sales in 2035 (Figure 58), the largest share among unconventional vehicle types. Manufacturers currently receive incentives for selling FFVs, through fuel economy credits that count toward CAFE compliance. However, due to limitations on gasoline blending, FFVs will also play a critical role in meeting the RFS mandate for biofuels. Although these credits are phased out by 2020, FFVs make up more than 20 percent of all new LDV sales in 2035, in part because of their increased availability.

Four types of hybrid vehicle are expected to be available for sale by 2035: standard gasoline-electric or diesel-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). MHEVs, in which the gasoline engine is turned off only when switching to battery power when the vehicle is idling, represent 53 percent of hybrid LDV sales and 13 percent of new LDV sales in 2035. HEVs have the second-largest share, at 37 percent of hybrid LDV sales. PHEV-10s make up 9 percent and PHEV-40s make up 2 percent of all hybrid LDV sales in 2035 in the Reference case, or about 500,000 PHEVS in total.

Residential and commercial sectors dominate electricity demand growth

Figure 59. U.S. electricity demand growth, 1950-2035 (percent, 3-year moving average)



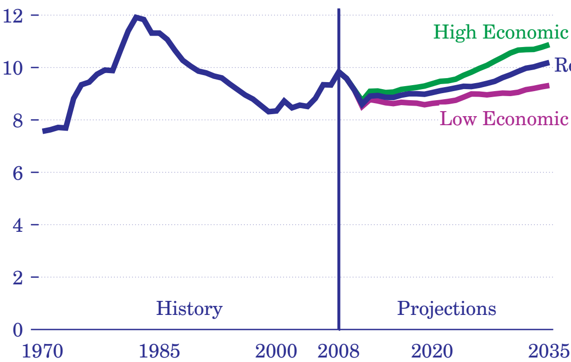
Electricity demand increases in response to population growth and economic growth and fluctuates in the short term in response to business cycles and weather trends. Over the long term, electricity demand growth has slowed progressively in each decade since the 1950s. After growing by 9.8 percent per year in the 1950s, electricity demand (including retail sales and direct use) increased by 2.4 percent per year in the 1990s, and from 2000 to 2008 it grew on average by 0.9 percent per year. The slower growth continues in the *AEO2010* Reference case, as increased demand for electricity services is offset by efficiency gains from new appliance efficiency standards and investment in energy-efficient equipment.

Total electricity demand increases by 30 percent in the Reference case (an average of 1.0 percent per year), from 3,873 billion kilowatthours in 2008 to 5,021 billion kilowatthours in 2035 (Figure 59). The largest percentage increase is in the commercial sector (42 percent), with the service industries continuing to lead the growth. Residential electricity demand increases by 24 percent, due to growth in population and disposable income and continued population shifts to warmer regions with greater cooling requirements. Total industrial electricity demand grows by only 3 percent from 2008 to 2035, as a result of efficiency gains and slow growth in industrial production, particularly in the energy-intensive industries.

In the transportation sector, penetration of PHEVs by 2035 is not sufficient to reverse the slowing trend in electricity demand growth, because for every 1 million PHEV-40 vehicles added, U.S. electricity demand increases by only about 0.1 percent.

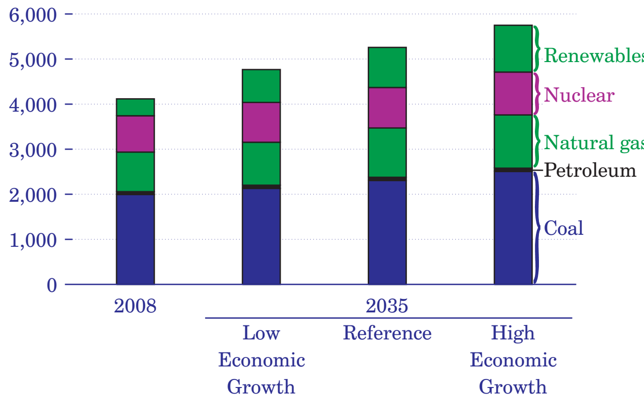
Electricity prices moderate in the near term, then rise gradually

Figure 60. Average annual U.S. retail electricity prices in three cases, 1970-2035 (2008 cents per kilowatthour)



Coal-fired power plants provide largest share of electricity supply

Figure 61. Electricity generation by fuel in three cases, 2008 and 2035 (billion kilowatthours)



Real electricity prices vary, depending on the economy, fuel prices, regulations, competition in wholesale and retail markets, and costs of new generation. In the *AEO2010* Reference case, average annual electricity prices fall from 9.8 cents per kilowatthour (2008 dollars) in 2008 to 8.6 cents per kilowatthour in 2011 because of a drop in fossil fuel prices and lower demand that coincides with the startup of new renewable, natural gas, and coal-fired capacity. After 2011, prices rise to 10.2 cents per kilowatthour in 2035 (Figure 60) in response to rising fuel prices and the construction of new power plants as demand rises.

Electricity prices are influenced by economic activity. In the High Economic Growth case, electricity prices rise to 10.9 cents per kilowatthour in 2035; in the Low Growth case they rise to only 9.3 cents per kilowatthour.

Electricity prices are based on generation, transmission, and distribution costs. Fuel costs account for most of the generation costs for natural-gas- and oil-fired plants but much less for coal and nuclear plants. There are no fuel costs associated with wind and solar plants. In competitive wholesale markets, natural gas and liquid fuel costs often set hourly prices. With natural-gas-fired generation increasing throughout the Reference case projection, natural gas prices have the greatest impact on electricity prices. Transmission costs rise by 33 percent from 2008 to 2035, as new infrastructure is built but still make up only 9 percent of average electricity prices by the end of the projection period. Distribution costs vary over time and are about the same in 2035 as in 2008.

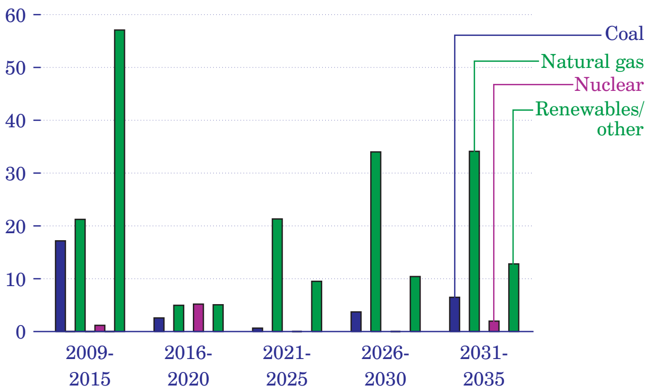
In the Reference case, without GHG regulations, coal accounts for the largest share of total electricity generation (Figure 61). With slow growth in electricity demand, little new coal-fired capacity is added, and the coal share falls from 48 percent in 2008 to 44 percent in 2035. (A 3-percent premium is added to the financing cost for CO_2-intensive technologies to reflect the potential for CO_2 regulation to reduce the competitiveness of coal with other technologies.)

The natural gas share of generation, at 21 percent in 2008, rose in 2009 when natural gas prices fell. Over the next few years, with slow growth in electricity demand, completion of coal plants under construction, and addition of new renewable capacity, the gas share falls, before trending up to 21 percent in 2035. The near- to mid-term downturn in natural gas generation might be dampened if new policies made coal use for electricity generation less attractive, or if growth in renewable generation were slower than projected. Renewable generation, supported by Federal and State tax incentives and ARRA funding, shows the strongest growth in the Reference case and is 2.4-fold higher in 2035 than in 2008. The renewable share of generation grows from 9 percent in 2008 to 17 percent in 2035. Although generation from nuclear plants increases by 11 percent, their share of total generation falls from 20 percent in 2008 to 17 percent in 2035.

Growth in demand for electricity varies with different assumptions about future economic conditions. In 2035, 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 9 percent below the Reference case.

Most new capacity additions use natural gas and renewables

Figure 62. Electricity generation capacity additions by fuel type, 2009-2035 (gigawatts)



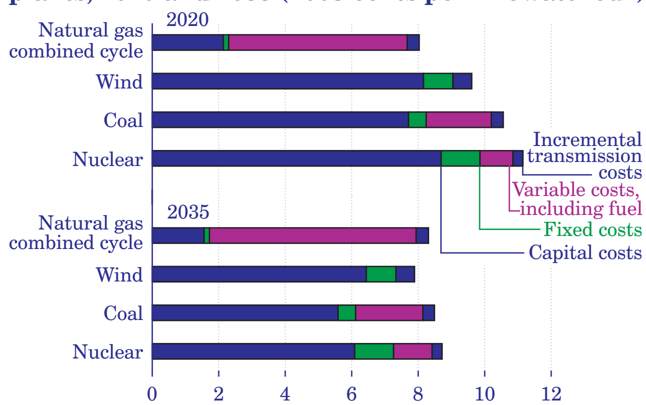
Decisions to add capacity and the choice of fuel type depend on a number of factors [*82*]. With growing electricity demand and the expected retirement of 45 gigawatts of existing capacity, 250 gigawatts of new generating capacity (including end-use CHP) will be needed between 2009 and 2035 (Figure 62).

Natural-gas-fired plants account for 46 percent of capacity additions in the Reference case, as compared with 37 percent for renewables, 12 percent for coal-fired plants, and 3 percent for nuclear. Escalating construction costs have the largest impact on the more capital-intensive generation technologies, including renewables, coal, and nuclear. However, Federal tax incentives, State energy programs, and rising prices for fossil fuels increase the competitiveness of renewable and nuclear capacity. In contrast, uncertainty about future limits on GHG emissions and other possible environmental regulations reduces the competitiveness of coal (reflected in the *AEO2010* Reference case by adding 3 percentage points to the cost of capital for new coal-fired capacity). The incentives extended and expanded by the ARRA have previously resulted in considerable growth in renewable capacity, and this trend is expected to continue.

Capacity additions also are affected by demand growth and by fuel prices. Capacity additions from 2009 to 2035 range from 158 gigawatts in the Low Economic Growth case to 341 gigawatts in the High Economic Growth case. With higher fuel costs in the *AEO2010* High Oil Price case, fewer natural-gas-fired plants are added, because fuel costs make up a relatively large share of their total expenditures.

Costs and regulatory uncertainties vary across options for new capacity

Figure 63. Levelized electricity costs for new power plants, 2020 and 2035 (2008 cents per kilowatthour)



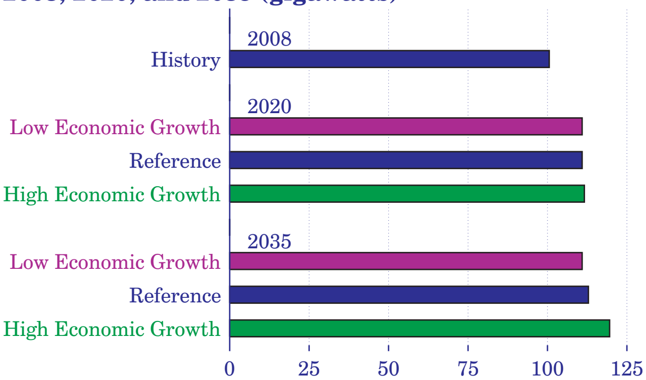
Technology choices for new generating capacity typically are made to minimize costs while meeting local and Federal emissions standards. Capacity expansion decisions consider capital, operating, and transmission costs. Coal-fired, nuclear, and renewable plants are capital-intensive, while operating (fuel) expenditures make up most of the costs for gas-fired capacity (Figure 63) [*83*]. Capital costs depend on such factors as equipment costs, interest rates, and cost-recovery periods. Fuel costs can vary according to fuel prices, plant operating efficiency, resource availability, and transportation costs. Some technologies and fuels also receive subsidies, such as PTCs and ITCs.

Regulatory uncertainty also affects capacity planning decisions. New coal-fired plants could be required to install CCS equipment, resulting in higher material, labor, and operating costs. Alternatively, coal plants without carbon controls could incur higher costs 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 in this area.

Capital costs can decline over time as developers gain experience with a given technology. In the *AEO2010* Reference case, capital costs of new technologies are adjusted upward initially, to reflect the optimism inherent in early 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, resulting in reduced variable costs unless increases in fuel costs exceed the savings from efficiency gains.

EPACT2005 tax credits stimulate some nuclear builds

Figure 64. Electricity generating capacity at U.S. nuclear power plants in three cases, 2008, 2020, and 2035 (gigawatts)



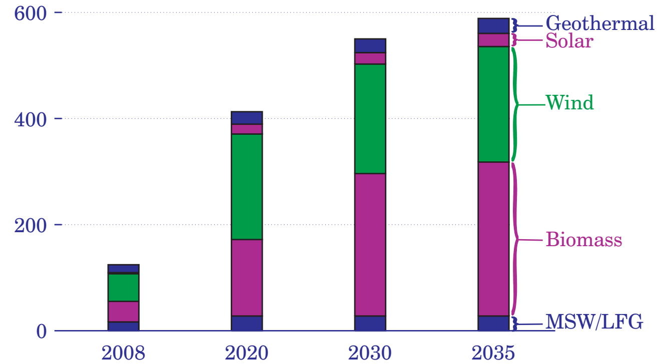
In the *AEO2010* Reference case, nuclear power capacity increases from 100.6 gigawatts in 2008 to 112.9 gigawatts in 2035 (Figure 64), including 4.0 gigawatts of expansion at existing plants and 8.4 gigawatts of new capacity. The Reference case includes a second unit at the Watts Bar site, where construction was halted in 1988 when the plant was partially completed. Estimated costs for new nuclear plants have continued to rise, making new investments in nuclear power uncertain. In the Reference case, only about six new nuclear power plants are completed by 2035.

All existing nuclear units continue to operate through 2035 in the Reference case, which assumes that they will apply for, and receive, operating license renewals, including in some cases a second 20-year extension after they reach 60 years of operation. With costs for natural-gas-fired generation rising and future regulation of GHG emissions uncertain, the economics of keeping existing nuclear power plants in operation are favorable.

Nuclear capacity additions vary with assumptions about overall demand for electricity and the prices of other fuels. 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 2008 to 2035 vary from 6 to 15 gigawatts. The first 6 gigawatts of new nuclear capacity is built in all cases, based on tax incentives and loan guarantees. More new nuclear capacity is built in the High Economic Growth and High Oil Price cases, because overall capacity requirements are higher and/or alternatives are more expensive.

Biomass and wind lead growth in renewable generation

Figure 65. Nonhydroelectric renewable electricity generation by energy source, 2008-2035 (billion kilowatthours)

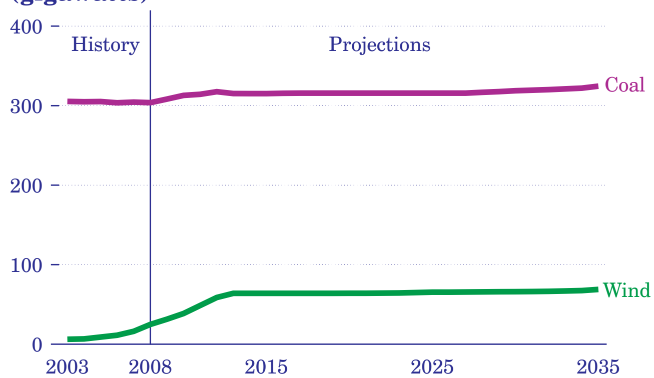


Use of renewable energy resources in the electric power sector increases sharply in the *AEO2010* Reference case (Figure 65). Nonhydroelectric renewable generation accounts for 41 percent of the growth in total electricity generation from 2008 to 2035, supported by extension of Federal tax credits, State requirements for renewable electricity generation, and the loan guarantee program in EPACT2005 and ARRA. Wind power and biomass provide the largest share of the growth. Generation from wind power increases from 1.3 percent of total generation in 2008 to 4.1 percent in 2035. Generation from biomass, both in the electric power sector and from end-use cogeneration, grows from 0.9 percent of total generation in 2008 to 5.5 percent in 2035. A large portion of the increase in biomass generation comes from increased co-firing—a process in which biomass is mixed with coal in existing coal-fired plants, displacing some of the coal that would otherwise be burned.

Renewable electricity generation also grows in the end-use sectors as a result of the EISA2007 RFS, which requires increased use of biofuels produced at biorefineries. At some BTL facilities, synthetic gas from the biomass conversion process is used for electricity generation. As in previous *AEO*s, solar technologies are too costly for widespread use in wholesale power applications, but demonstration programs and State policies support some growth in central-station PV. In addition, State programs, Federal tax rebates, and utility programs encourage small-scale, distributed PV generation applications, which grow rapidly over the projection period.

Wind power dominates renewable capacity growth in the near term

Figure 66. Grid-connected coal-fired and wind-powered generating capacity, 2003-2035 (gigawatts)



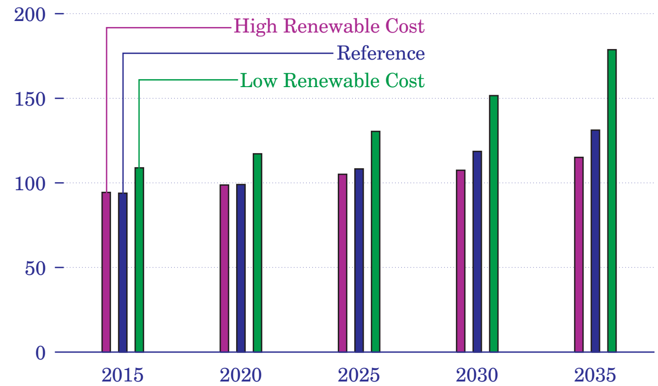
In the *AEO2010* Reference case, renewable capacity—particularly, wind-powered capacity—increases rapidly from 2008 to 2013 in response to the Federal PTC for wind, ARRA funding, and State RPS legislation. Growth in renewable capacity slows dramatically after 2014 because of the expiration of the Federal PTC for wind and the completion of projects expected to be supported by ARRA funding. The growth before 2013 is adequate to meet State RPS-mandated renewable requirements through about 2030; however, renewable capacity begins to grow again after 2030 to meet the State RPS mandates.

Installed wind capacity grew by about 19 gigawatts from 2003 to 2008, a trend that continues in the Reference case with the installation of 39 gigawatts from 2008 to 2013, more than doubling wind capacity in the United States (Figure 66). The near-term growth of other renewable capacity, however, is limited. Geothermal capacity is restricted to a relatively small number of suitable sites; solar capacity remains too costly for widespread implementation; and energy crops do not become economical before 2015. Other biomass resources that could be used for electric power generation are used instead to produce biofuels in order to meet the Federal RFS, leading to a small increase in electricity generation at biorefineries.

With new generation needed in the later years of the projection, State RPS programs lead to the installation of more dedicated renewable capacity. Dedicated biomass capacity increases by nearly 5 gigawatts from 2030 to 2035, largely using biomass feedstocks from energy crops. As a result, co-firing of renewables in coal-fired boilers decreases late in the projection.

Higher or lower costs affect growth in renewable generation capacity

Figure 67. Nonhydropower renewable generation capacity in three cases, 2015-2035 (gigawatts)



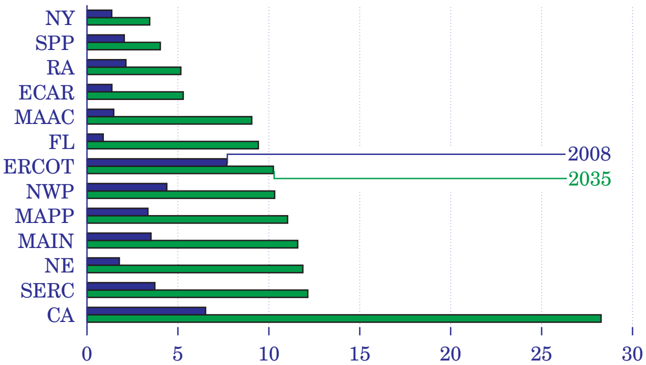
Renewable generation grows from a 9-percent share of total electricity production in 2008 to a 17-percent share in 2035 in the Reference case. The increase is supported by Federal tax credits, State RPS programs, and a premium added to the cost of long-lived carbon-intensive technologies, reflecting market behavior with regard to potential carbon regulations.

In the Reference case, capital costs for renewable capacity in 2035 are 20 to 50 percent lower than in 2008. Two additional cases show the effects of technology costs on the use of renewables for generation (Figure 67). In the Low Renewable Cost case, costs for renewable generation technologies in 2035 are 25 percent lower than in the Reference case, but in the High Renewable Cost case they do not change from their 2009 levels. In the Low Renewable Cost case, renewable generation in 2035 totals 1,145 billion kilowatthours, or a 22-percent share of all generation. In the High Renewable Cost case, total renewable generation in 2035 is 786 billion kilowatthours and accounts for 15 percent of generation. Although the costs for renewable generation are higher in the High Renewable Cost case, its growth is still supported by PTCs in the early years of the projection and continued State mandates for renewable electricity in the later years.

With lower costs, geothermal electricity generation in the Low Renewable Cost case is almost 70 percent higher than in the Reference case in 2035, and generation from biomass and wind also show significant increases. In the High Renewable Cost case, wind actually increases from its Reference case value in 2035, reflecting a decrease in biomass combustion at biofuels plants.

State portfolio standards increase renewable generating capacity

Figure 68. Regional growth in nonhydroelectric renewable electricity generation capacity, including end-use capacity, 2008-2035 (gigawatts)

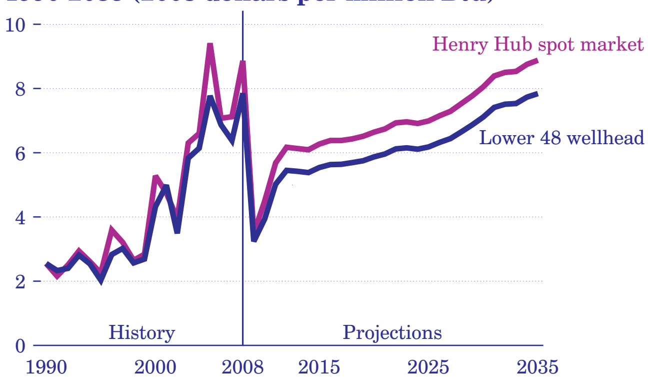


Regional additions of renewable generating capacity depend for the most part on State RPS programs. As of October 31, 2009, there were mandatory RPS programs in 30 States and nonbinding renewable goals in 5 States [*84*]. From 2008 to 2035, California installs the most renewable capacity, 22 gigawatts (Figure 68), primarily new wind capacity but also including 3.1 gigawatts of distributed PV capacity. New England installs more than 8 gigawatts of new wind capacity, representing the second-largest regional growth of the technology (see Figure F2 in Appendix F for a map of the regions). Florida and the Mid-Atlantic account for 80 percent of the dedicated biomass capacity installed by 2035 in the electric power sector (mostly later in the period).

Distributed biomass capacity corresponds largely with the location of cellulosic ethanol plants. Although the Southeast has ample biomass resources, only small amounts of renewable capacity are installed in the region's electric power sector in the absence of State RPS programs, whereas distributed biomass capacity increases by more than 6 gigawatts from 2008 to 2035. Geothermal energy, which is constrained geographically by the availability of local resources, is installed exclusively in the Southwest and California. The same regions have the greatest resource potential for large-scale solar capacity, but because of its high cost only a small amount is installed. Most of the increase in solar capacity consists of distributed PV, and some States in the Northeast (New Jersey, for example) have mandates or provide other incentives for PV installations. Approximately 1.6 gigawatts of distributed PV capacity is installed in the Mid-Atlantic region by 2035.

Natural gas prices rise but remain attractive relative to oil

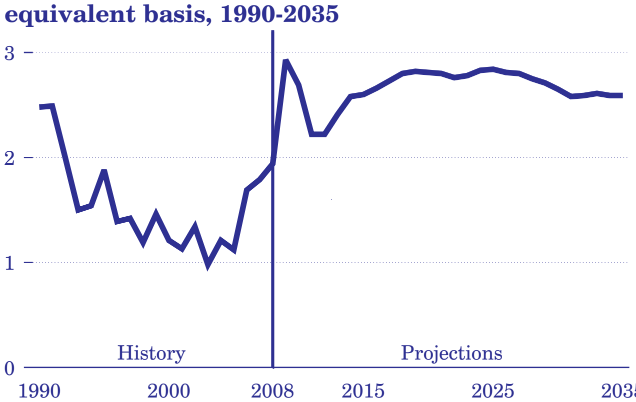
Figure 69. Annual average lower 48 wellhead and Henry Hub spot market prices for natural gas, 1990-2035 (2008 dollars per million Btu)



Average natural gas prices generally increase in the Reference case, as higher cost resources are brought on line to meet demand growth (Figure 69). The price increase is tempered by improvements in technology. There is a great deal of uncertainty about the long-term trend in natural gas prices, however, particularly in light of the growing development of shale gas resources.

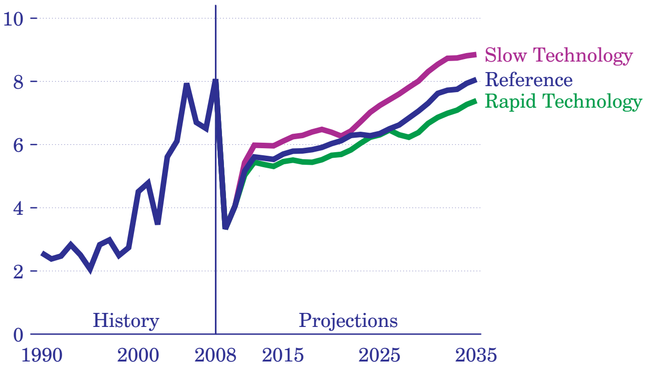
The ratio of low-sulfur light crude oil prices to Henry Hub natural gas prices on an energy equivalent basis remains high relative to the historical average throughout the projection (Figure 70). The ratio is maintained by growing worldwide demand for transportation fuels and robust North American natural gas supply relative to demand. Still, increased use of natural gas as a substitute for petroleum in some transportation uses and/or as a GTL feedstock could increase natural gas prices and narrow the ratio.

Figure 70. Ratio of low-sulfur light crude oil price to Henry Hub natural gas price on an energy equivalent basis, 1990-2035



Natural gas prices vary with economic growth and technology progress

Figure 71. Annual average lower 48 wellhead prices for natural gas in three technology cases, 1990-2035 (2008 dollars per thousand cubic feet)



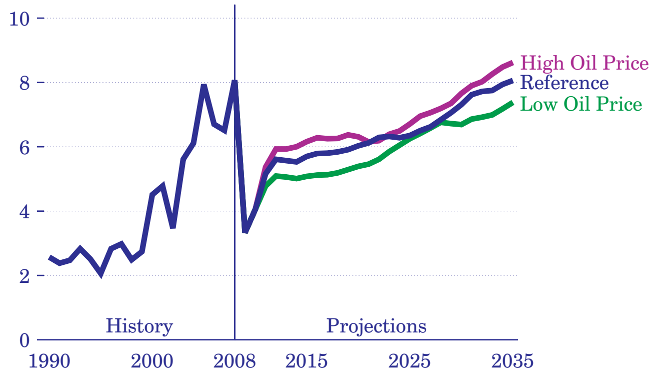
The extent to which natural gas prices increase in the *AEO2010* Reference case and in the Rapid and Slow Technology cases depends on assumptions about the rate of improvement in natural gas exploration and production technologies. Technology improvements, in addition to reducing drilling and operating costs and expanding the economically recoverable resource base, also affect the timing of production increases from sources such as shale gas.

Technology improvement is particularly important to the production of natural gas from shale formations, which can typically be produced at lower incremental cost, but 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 accelerates growth in production. Technology improvements also lead to earlier initial production and higher production rates, which result in favorable economics that encourage further growth. The downward pressure placed on natural gas prices by more rapid technology improvement is, however, offset somewhat by higher levels of consumption.

In the Slow Technology case, slower declines in exploration and development costs lead to higher natural gas prices and lower levels of consumption than in the Reference case (Figure 71). In both the Slow and Rapid Technology cases, as in the Reference case, completion of the Alaska pipeline (in 2020 and 2027 in the Slow Technology and Rapid Technology cases, respectively) results in a temporary decline in natural gas prices.

U.S. natural gas prices have limited sensitivity to oil prices

Figure 72. Annual average lower 48 wellhead prices for natural gas in three oil price cases, 1990-2035 (2008 dollars per thousand cubic feet)



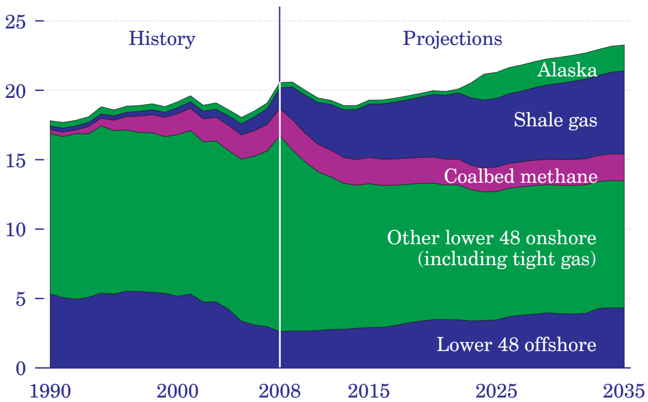
Oil prices have small but measurable impacts on domestic natural gas production and prices, causing them to increase in the High Oil Price case and decrease in the Low Oil Price case. Higher or lower oil prices lead to higher or lower levels of drilling activity, which affect the costs of labor and key commodities, such as steel, that factor into production costs for both industries. As a result, domestic natural gas prices rise and fall with oil prices (Figure 72). The changes are offset in part by increased production of liquids associated with natural gas production when oil prices are higher, as well as the increase in recovery of associated gas that comes with increased oil production.

Different oil price assumptions also affect domestic natural gas supply through their effects on global availability of natural gas exports. Although U.S. natural gas consumption is lower in the High Oil Price case, higher oil prices tend to increase natural gas consumption in international markets, where it is used instead of liquids and also to produce liquids, thereby reducing the amount of natural gas, particularly LNG, available for export to U.S. markets.

Internationally, there is a greater potential for shifting between oil and natural gas than in the United States. In addition, many European and Asian natural gas price contracts are tied to oil prices, and as a result world natural gas prices tend to move with oil prices. A stronger price linkage in the United States could occur with the development of new markets, such as GTL production, natural gas vehicles, or LNG exports.

Shale gas provides largest source of growth in U.S. natural gas supply

Figure 73. Natural gas production by source, 1990-2035 (trillion cubic feet)



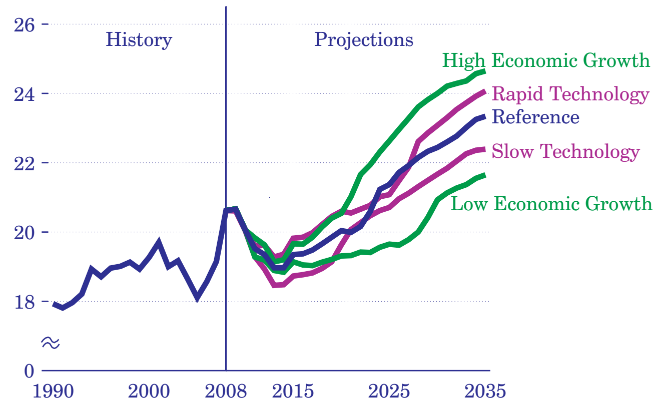
The increase in U.S. natural gas production from 2008 to 2035 in the *AEO2010* Reference case results primarily from continued growth in production of shale gas, recent discoveries in deep waters offshore, and, to a lesser extent, stranded natural gas brought to market after construction of the Alaska natural gas pipeline is completed in 2023 (Figure 73). Shale gas and coalbed methane make up 34 percent of total U.S. production in 2035, doubling their 17-percent share in 2008.

Shale gas is the largest contributor to the growth in production, while production from coalbed methane deposits remains relatively stable from 2008 to 2035. Advances in horizontal drilling and hydraulic fracturing techniques—as well as improved drill bits, steering systems, and instrumentation monitoring equipment—have contributed to higher success and recovery rates, reduced cycle times, lower costs, and shorter times required to bring new shale gas production to market.

Offshore natural gas, the bulk of which is from deep waters in the Gulf of Mexico, contributes significantly to domestic supply. Fields that started producing recently or are expected to start producing within the next few years include Great White, Norman, Shenzi, Tahiti, and Cascade. Production from the continued development of recent discoveries, as well as new discoveries, more than offsets production declines in older fields, resulting in a net increase in offshore production through 2035.

Economic growth and technology progress affect natural gas supply

Figure 74. Total U.S. natural gas production in five cases, 1990-2035 (trillion cubic feet)



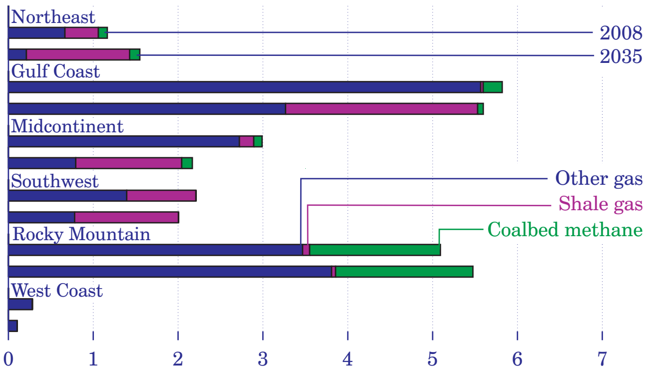
Growth in domestic natural gas production is affected by economic growth and advances in exploration and production technology. The effect of economic growth on domestic natural gas production results from its impact on natural gas consumption and prices. Improvements in technology reduce natural gas drilling and production costs, increase the productive capacity of natural gas wells, and increase the number of successful wells.

Natural gas consumption in 2035 is 2.1 trillion cubic feet higher in the High Economic Growth case than in the Reference case. More than one-half of the increase in the High Growth case is met by an increase of 1.3 trillion cubic feet in domestic production (Figure 74); the remainder is met by an increase in pipeline imports from Canada, supported in part by the introduction of Mackenzie Delta gas in 2032. Roughly one-third of the increase in domestic production comes from shale gas, one-third comes from other lower 48 onshore production, excluding coalbed methane production, and the balance comes from coalbed methane, offshore, and Alaska.

Annual production of natural gas from 2008 to 2035 is, on average, 0.4 trillion cubic feet higher in the Rapid Technology case than in the Reference case. The additional production from the lower 48 States places downward pressure on natural gas prices and delays construction of the Alaska natural gas pipeline—from 2023 in the Reference case to 2027 in the Rapid Technology case. In the Slow Technology case, average annual production of domestic natural gas from 2008 to 2035 is 0.5 trillion cubic feet lower than in the Reference case from 2008 to 2035.

Natural gas production grows in Northeast, Rocky Mountain regions

Figure 75. Lower 48 onshore natural gas production by region, 2008 and 2035 (trillion cubic feet)



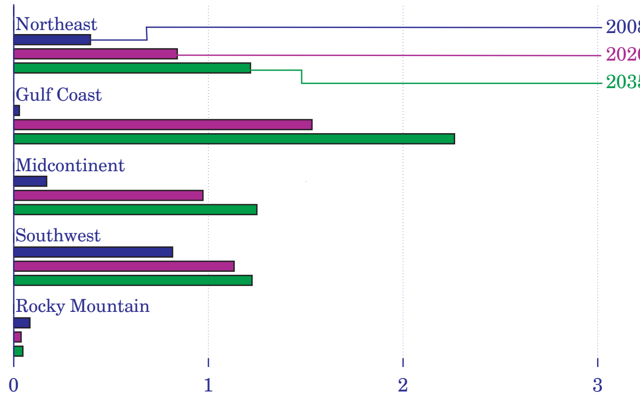
A 4-fold increase in shale gas production from 2008 to 2035 more than offsets a 31-percent decline in other lower 48 onshore natural gas production in the *AEO-2010* Reference case. Significant increases in shale gas production are expected in the Northeast, Gulf Coast, and Midcontinent regions (Figure 75). (See Figure F4 in Appendix F for a map of the regions.) Coalbed methane production, which has grown rapidly over the past several decades, is relatively stable through 2035 and is confined largely to the Rocky Mountain region.

In the Northeast, natural gas production grows by 34 percent from 2008 to 2035 in the Reference case, led by increased development of shale gas. The growth has the potential to replace some of the Northeast's current natural gas supply that comes from the U.S. Gulf Coast and from Canada, resulting in more Gulf Coast supply available to other regions. This has the potential to moderate natural gas prices at the Henry Hub.

While U.S. shale gas production increases, total onshore natural gas production declines slightly in the Gulf Coast region, by 27 percent in the Midcontinent region, and by 9 percent in the Southwest from 2008 to 2035. The Rocky Mountain region is expected to see an increase in total production (8 percent), largely from tight sand formations (which are included in the "other gas" category). The largest decline in total natural gas production, about 63 percent, is projected for the West Coast region, where no shale gas or coalbed methane is produced.

Shale gas production grows substantially in most regions

Figure 76. Shale gas production by region, 2008, 2020, and 2035 (trillion cubic feet)



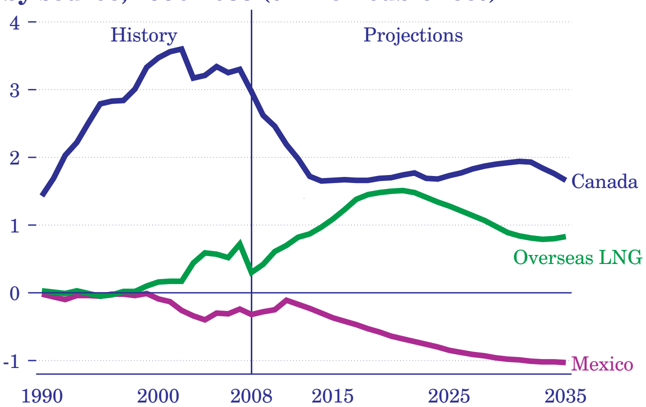
Growth in natural gas production from shale formations offsets declines in other supply sources nationwide throughout the *AEO2010* Reference case projection. The growth depends, in part, on future growth in demand for natural gas. With an assumed 347 trillion cubic feet of technically recoverable shale gas, the potential for increased production is large. The true potential of the U.S. shale gas resource remains uncertain, however, as estimates vary and experience continues to provide new information.

Shale gas production occurs in new and sometimes previously abandoned areas, where its production may require increases in processing, storage, and pipeline capacity. Although production from the Antrim shale has started declining, and development in parts of the Marcellus shale has been inhibited somewhat by limitations on the issuance of drilling permits [*85*], shale gas production in the Northeast region more than doubles from 2008 to 2035 in the Reference case (Figure 76).

In the Gulf Coast region, where the Haynesville play is expected to become a major contributor, shale gas compensates for almost 91 percent of the decline in other natural gas production. In the Midcontinent region, production from the Fayetteville and Woodford shales offsets approximately 57 percent of the decline in other natural gas production. And in the Southwest region, production from the older Barnett shale play offsets approximately 66 percent of the decline in other natural gas production. There is no projected shale gas production in the West Coast region.

U.S. net imports of natural gas decline as domestic production rises

Figure 77. U.S. net imports of natural gas by source, 1990-2035 (trillion cubic feet)



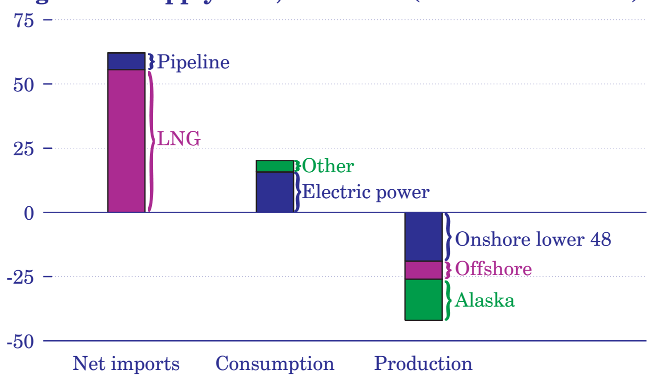
U.S. net imports of natural gas decline in the Reference case from 13 percent of total supply in 2008 to 6 percent in 2035. The reduction consists primarily of lower imports from Canada and higher exports to Mexico, as a result of demand growth in both countries that outpaces the growth in their production, as well as increased U.S. production.

In the Reference case, imports from Canada decline rapidly through 2014 (Figure 77), as increased production from growing sources, such as shale gas, is not yet sufficient to offset the decline in other sources. After 2014, U.S. imports from Canada stabilize at 1.7 to 1.9 trillion cubic feet per year through 2035. However, the size of Canada's shale gas resource is uncertain at present. In the Low Technology and High Economic Growth cases, which include higher natural gas prices, a pipeline from the Mackenzie Delta is constructed before 2035. With lower natural gas prices, it is not completed by 2035.

U.S. imports of LNG increase to a high of 1.5 trillion cubic feet in 2021 as new liquefaction capacity is built in exporting countries, then decline as demand from other importing countries grows to absorb more of the output from the new capacity. Other importing countries have few economical alternatives to LNG, whereas the United States has ample supplies of domestic natural gas. Therefore, U.S. import levels depend primarily on the amount of excess liquefaction capacity available. Domestic production keeps U.S. natural gas prices low relative to world LNG prices, which remain tied to oil prices in many foreign markets. Actual import volumes are likely to vary notably around the trend line.

High LNG supply case illustrates uncertainty in future import levels

Figure 78. Cumulative difference from Reference case natural gas supply and consumption in the High LNG Supply case, 2008-2035 (trillion cubic feet)



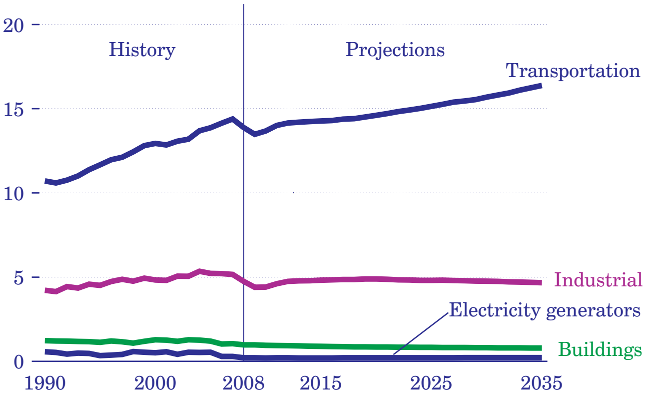
U.S. imports of LNG depend on world liquefaction capacity, world demand for LNG, and U.S. natural gas prices. When there is excess natural gas supply in world markets (for example, during years with warmer weather than normal), more LNG becomes available for U.S. imports. The *AEO2010* High LNG case assumes the availability of more LNG imports to North America than in the Reference case—up to 5 times more in 2035 and cumulatively 2.9 times more from 2009 to 2035, or a total of 70 trillion cubic feet.

The increase in LNG imports results in lower wellhead prices, with annual wellhead prices lower in the High LNG case than in the Reference case by 7 to 18 percent ($0.55 to $1.42 per thousand cubic feet) during the period from 2020 to 2035. A major impact of the increase in LNG imports in the High LNG case is on the timing of the Alaska pipeline, which is opened in 2023 in the Reference case but delayed until 2033 in the High LNG case. In the lower 48 States, a major impact of increased LNG imports is reduced production of onshore natural gas and an even larger percentage reduction in offshore production, because lower prices imply that fewer U.S. natural gas resources are economical to produce.

Effects on U.S. natural gas consumption in the High LNG case are primarily in the price-responsive electricity generation sector, where natural gas competes with coal and renewables. The electricity generation sector accounts for 80 percent of the cumulative difference in consumption between the two cases (Figure 78).

Transportation uses spur growth in liquid fuels consumption

Figure 79. Liquid fuels consumption by sector, 1990-2035 (million barrels per day)



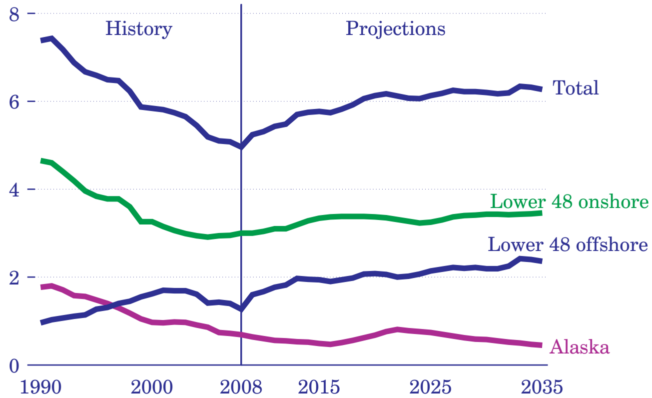
U.S. consumption of liquid fuels—including fuels from petroleum and, increasingly, those derived from fuels such as biomass, coal, and natural gas—totals 22.1 million barrels per day in 2035 in the Reference case, an increase of 2.5 million barrels per day over the 2008 total (Figure 79). In all sectors except transportation, liquid fuel consumption remains at roughly the same level over the projection period. As a result, the transportation sector accounts for 74 percent of total liquid fuels consumption in 2035, up from 71 percent in 2008.

Motor gasoline, ultra-low-sulfur diesel, and jet fuel are the main fuels consumed in the transportation sector. Although EIA expects that the most recent increases in U.S. CAFE standards will increase the fuel efficiency of motor vehicles, the growth in demand for transportation services that results from increases in population and GDP outpaces the expected improvements in efficiency.

Growth in demand for transportation fuels is met primarily by diesel fuel and biofuels. While motor gasoline consumption (including ethanol used in E10) increases by 0.1 million barrels per day from 2008 to 2035 in the Reference case, consumption of diesel fuel and E85 increases by 1.0 and 1.2 million barrels per day, respectively, over the period. Growth in demand for biofuels is primarily a result of the EISA2007 RFS. Growth in demand for diesel fuel results from the increasing sales of diesel LDVs that are needed to meet the new CAFE standards, as well as an increase in shipping that leads to more consumption of diesel by heavy freight trucks.

U.S. crude oil production increases as projected world oil prices rise

Figure 80. Domestic crude oil production by source, 1990-2035 (million barrels per day)

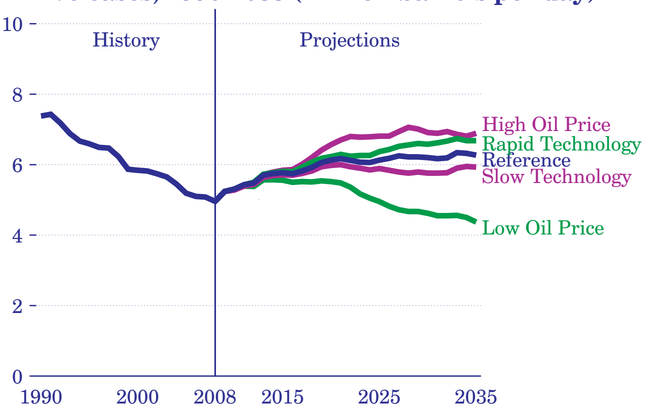


Total U.S. crude production increases from 2008 to 2035, as rising world oil prices spur both onshore and offshore drilling. In the short term, a vast majority of the increase comes from deepwater offshore fields. Fields that started producing in 2009 or are expected to start in the next few years include Great White, Norman, Tahiti, Gomez, Cascade, and Chinook. All are in water deeper than 800 meters, and most are in the Central Gulf of Mexico. Production from those fields, combined with increased production from fields that started producing in 2007 and 2008, contributes to the near-term growth in offshore production. Over the longer term, production from the continued development of other recent discoveries, as well as new discoveries, offsets production declines in older fields, resulting in an increase in production through 2035 (Figure 80).

Removal of the Congressional moratorium on drilling in the Eastern Gulf of Mexico, Atlantic, and Pacific regions of the Outer Continental Shelf also allows for more crude oil production from offshore areas in the Pacific after 2016, in the Atlantic after 2021, and in the Eastern Gulf of Mexico after 2025 [*86*]. In 2035, U.S. crude oil production includes 0.4 million barrels per day from the Pacific offshore, 0.2 million from the Atlantic offshore, and 0.1 million from the Eastern Gulf of Mexico. Lower 48 onshore production of crude oil continues to increase through 2035, primarily as a result of wider application of CO_2 EOR techniques. EOR makes up 37 percent of total onshore production in 2035, up from 12 percent in 2008. Continued exploitation of the Bakken shale formation and the startup of oil shale liquids production after 2023 also contribute to the growth in onshore oil production.

U.S. oil production depends on prices and technology

Figure 81. Total U.S. crude oil production in five cases, 1990-2035 (million barrels per day)

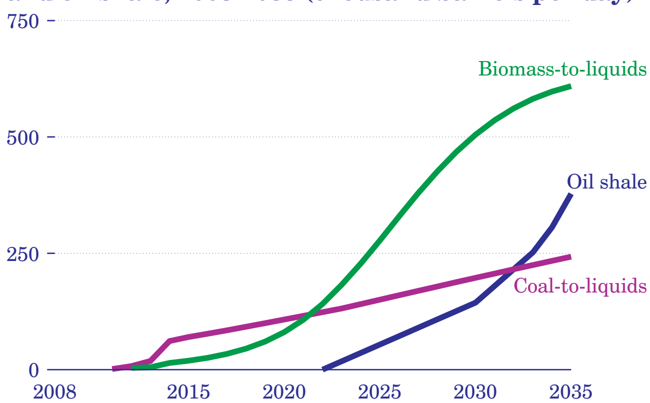


U.S. crude oil production, both onshore and offshore, is sensitive to future world oil prices and advances in technology. The rate of growth in domestic crude oil production depends largely on assumptions about world oil prices (Figure 81), as remaining onshore resources typically require more costly secondary or tertiary recovery techniques. Generally, high-cost projects are more economical when world oil prices are high. However, long lead times from discovery to production limit the increase in production, particularly offshore, over the projection period. Production from deepwater offshore projects and from lower 48 onshore EOR projects accounts for most of the variation in domestic production in the High and Low World Oil Price cases.

Different assumptions about rates of technology improvement also have significant effects on crude oil production, through their effects on exploration and development costs, success rates, and production efficiencies. Advances in horizontal drilling and hydraulic fracturing techniques, as well as improved drill bits, steering systems, and instrumentation monitoring equipment, are among the key advances that have contributed to increases in domestic production over the past few years, reversing the historical trend of declining U.S. crude oil production. Horizontal drilling, in particular, is regarded by many as one of the most valuable technologies introduced in the industry, because it can be used in many situations where conventional drilling is impossible or prohibitively expensive.

Liquids production from biomass, coal, and oil grows as oil prices rise

Figure 82. Liquids production from biomass, coal, and oil shale, 2008-2035 (thousand barrels per day)



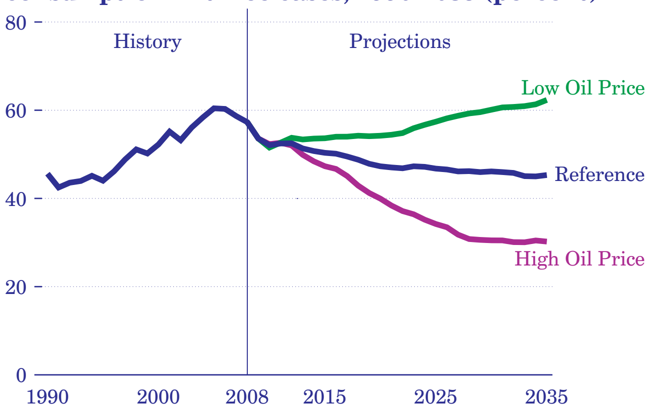
Liquids produced from BTL and CTL, as well as oil shale production, become more significant as world oil prices increase. BTL production shows the most rapid rise in the *AEO2010* Reference case (Figure 82), as increases in the costs of petroleum-based feedstocks make alternative feedstocks, such as biomass, more cost-competitive. In addition, the carbon-mitigating potential of BTL fuels makes them more attractive in a carbon-conscious environment. Financial and technical difficulties, however, continue to provide major challenges to the penetration of BTL technology in the liquid fuels industry.

CTL production also grows in the Reference case, more rapidly than BTL in the early years but more slowly after 2020, so that total CTL production in 2035 is less than one-half the total for BTL. Although advances in coal liquefaction technology have made it commercially available in other countries, including South Africa, China, and Germany, the technical and financial risks of building what would be essentially a first-of-a-kind facility in the United States have discouraged significant investment thus far. In addition, the possibility of new legislation aimed at reducing U.S. GHG emissions creates further uncertainty for future investment in CTL.

With ongoing improvement in oil shale technology, commercial production starts in 2023 and increases rapidly to 1.7 percent of total U.S. liquids supply in 2035. However, oil shale development suffers from environmental, technical, and financial uncertainties similar to those for CTL.

Imports of liquid fuels vary with world oil price assumptions

Figure 83. Net import share of U.S. liquid fuels consumption in three cases, 1990-2035 (percent)



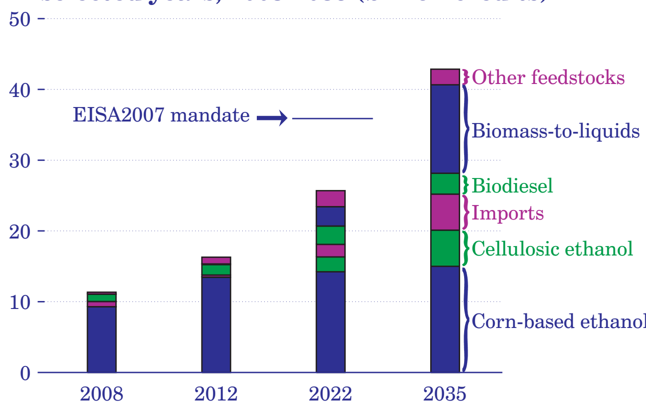
U.S. imports of liquid fuels, which grew steadily from the mid-1980s to 2005, decline significantly from 2008 to 2035 in the *AEO2010* Reference and High Oil Price cases, even as they continue to provide a major part of total U.S. liquids supply. Higher prices lead to more domestic production of oil and in combination with the RFS lead to more domestic biofuel production, while at the same time the higher energy prices moderate growth in overall demand for liquids.

The net import share of U.S. liquid fuels consumption fell from 60 percent in 2005 to 57 percent in 2008 and about 54 percent in 2009. That trend continues in the projections, with the net import share falling to 45 percent in the Reference case and to 30 percent in the High Oil Price case in 2035. Increased domestic production of crude oil and biofuels reduces the need for imports of crude oil and petroleum products in the High Oil Price case, but the import share of total consumption is still substantial (Figure 83). In the Low Oil Price case, the net import share rises to 62 percent in 2035. With lower prices for liquid fuels, demand increases while domestic production decreases, and more imports are needed to meet demand.

The above projections for net import shares are based on total U.S. consumption of all liquid fuels, including biofuels and other alternative fuels. When only petroleum consumption is considered (instead of total liquid fuels consumption), the net import share of petroleum declines from 57 percent in 2008 to 49 percent in 2035 in the Reference case.

EISA2007 RFS targets are not met in 2022 but are surpassed later

Figure 84. EISA2007 RFS credits earned in selected years, 2008-2035 (billion credits)



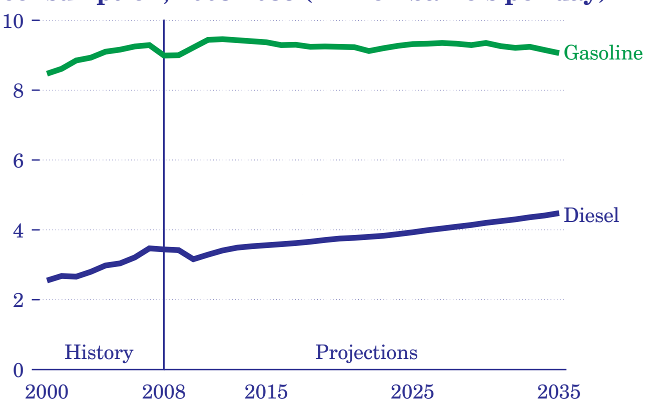
EISA2007 mandates a total RFS credit requirement of 36 billion gallons in 2022. Credits are equal to ethanol-equivalent gallons produced [*87*], except for the biodiesel schedule, which is based on actual volumes. BTL distillates receive a 1.7-gallon credit for each gallon produced, because the energy content of BTL fuels is higher than the energy content of ethanol. In total, 15 billion gallons of credits from conventional biofuels and 21 billion gallons from advanced biofuels—including 16 billion gallons from cellulosic biofuels—are required in 2022.

If available biofuel quantities are inadequate to meet the initial targets, EISA2007 provides for application of waivers and modification of applicable credit volumes. In the Reference case only 25.7 billion gallons of RFS credits are generated in 2022 (Figure 84), because economic and technological factors prevent cellulosic biofuel production from providing the credits that would be needed to meet the requirement.

Corn ethanol makes the largest contribution toward the RFS mandate, providing up to 14.2 billion credits in 2022. Cellulosic ethanol contributes 2.1 billion credits to the advanced and cellulosic biofuel requirement in 2022, and BTL contributes 2.5 billion credits. The remaining 6.9 billion gallons of credits for advanced biofuels in 2022 include ethanol imports, biodiesel, and renewable diesel. As the technologies mature, production of cellulosic ethanol and BTL increases to 5.1 billion and 9.6 billion gallons of credits, respectively, in 2035. Production of biofuels ultimately surpasses the RFS requirement as higher oil prices and lower production costs improve their competitiveness.

Refinery operations shift focus to diesel fuel production

Figure 85. U.S. motor gasoline and diesel fuel consumption, 2008-2035 (million barrels per day)



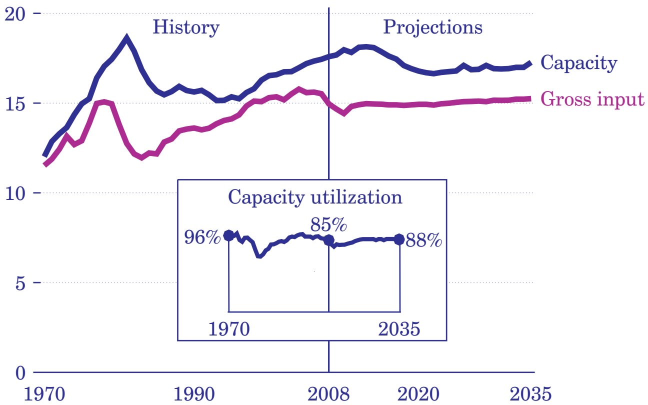
Diesel consumption increases steadily from 2008 to 2035 in the *AEO2010* Reference case, while motor gasoline consumption remains relatively flat (Figure 85). Increased consumption of ethanol in E85 is the main reason for the absence of substantial growth in petroleum-based gasoline consumption, which increases by less than 0.1 million barrels per day. In addition, however, the combination of increased diesel output and decreased refinery capacity leads to a shift in the product slate of U.S. refineries. Diesel consumption increases by approximately 1.0 million barrels per day from 2008 to 2035 in the Reference case, and diesel exports increase by approximately 0.2 million barrels per day. The increase in domestic demand for diesel fuel is a result of increased freight shipping activity.

Despite recent decreases in both demand for petroleum products and capacity utilization rates, total capacity expands in the near term as planned additions are completed. The planned additions are focused on diesel output for use in both domestic and foreign markets.

After peaking in 2012, refinery capacity is expected to decline by a total of approximately 0.8 million barrels per day from 2012 through 2035 as diesel fuel consumption continues to grow in the Reference case, resulting in a growing diesel share of refinery output.

Near-term increase in refinery capacity leads to a lower utilization rate

Figure 86. U.S. refinery capacity, 1970-2035 (million barrels per day)

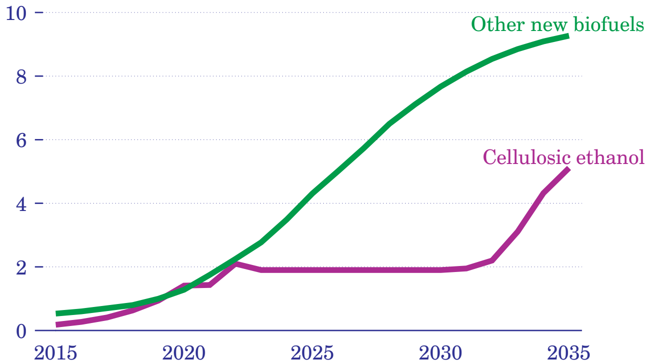


New projects to add capacity are underway at some domestic refineries, and most of those projects are scheduled to come on line in the next several years, adding approximately 500,000 barrels per day of new refining distillation capacity by the end of 2012. Two large expansion projects in Port Arthur, Texas, and Garyville, Louisiana, make up the majority of the new capacity [*88*]. The additional capacity will be added, in part, to meet the increase in demand for ultra-low-sulfur diesel fuel from 2008 to 2035. Some of it will be configured to process heavier and less desirable crude oils, capitalizing on their lower costs. In the near term, however, because the current economic downturn reduces demand for motor fuels, capacity utilization falls to approximately 80 percent in 2010 from 85 percent in 2008 (Figure 86).

After 2012, approximately 1.5 million barrels per day of existing capacity is taken out of service by 2022 in the *AEO2010* Reference case. The reduction in operating capacity, coupled with growth in demand for diesel fuel, increases capacity utilization to around 89 percent in 2020, and it remains at roughly that level through 2035. Given the current economic climate, the potential for future carbon mitigation legislation that could affect refiners, and the overall level of demand, EIA does not expect future capacity additions after 2013 in the Reference case or Low Oil Price case. Excess refinery capacity is fully utilized in the Low Oil Price case, but no new capacity is built.

New generation of biofuels helps meet renewable fuels standard

Figure 87. U.S. production of cellulosic ethanol and other new biofuels, 2015-2035 (billion gallons per year)

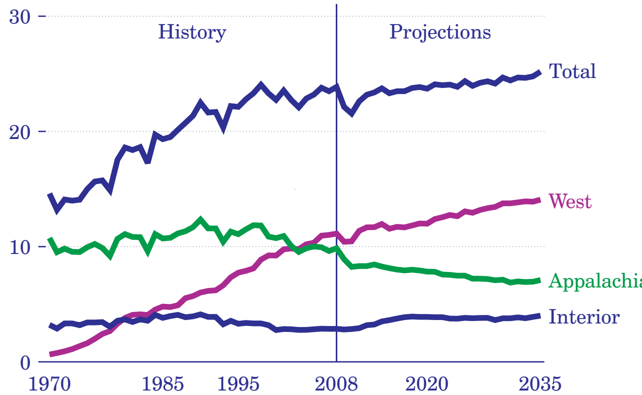


A number of new biofuels that begin to enter the U.S. market for transportation fuels in the later years of the *AEO2010* projection period contribute to meeting the EISA2007 RFS mandate. New BTL fuels include Fischer-Tropsch liquids, renewable diesel (also known as "green diesel"), and pyrolysis oils. The new fuels are assumed to satisfy both the advanced biofuel and cellulosic biofuel requirements in the RFS, because their life-cycle GHG emissions are 60 percent lower than those from conventional gasoline or diesel fuel. In 2035, production of those three fuels totals approximately 9.2 billion gallons, compared with 5.1 billion gallons of cellulosic ethanol (Figure 87).

Each of the other new biofuels has distinct advantages over cellulosic ethanol and first-generation biofuels, primarily in that they can be used in existing distribution networks and vehicle fleets, because their constituent chemical compounds are similar to those found in traditional petroleum-based fuels. Thus, they do not have the corrosive properties that limit the transportation of other biofuels through existing petroleum product pipelines, and the use of higher blends is not restricted to FFVs. This potentially avoids the substantial resource expenditures that would be required for development of new infrastructure for traditional biofuels and avoids a key barrier that ethanol faces in use beyond E10 blends. In addition, the technologies used to produce the new fuels can exploit a variety of feedstocks, including biomass and animal fats, which contributes to their attractive GHG profiles and production costs.

Coal production increases at a slower rate than in the past

Figure 88. Coal production by region, 1970-2035 (quadrillion Btu)



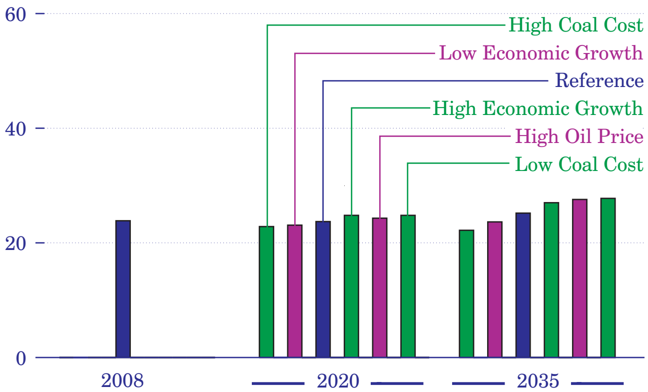
In the *AEO2010* Reference case, increasing coal use for electricity generation, along with the startup of several CTL plants, leads to growth in coal production averaging 0.2 percent per year from 2008 to 2035. This is significantly less than the 0.9-percent average growth rate for U.S. coal production from 1980 to 2008.

Western coal production increases through 2035 (Figure 88), but at a much slower rate than in the past. Both new and existing electric power plants are major sources of additional demand for Western coal. Low-cost supplies of coal from the West satisfy most of the additional fuel needs at coal-fired power plants both west and east of the Mississippi River.

Coal production in the Interior region (see Figure F6 in Appendix F for a map of the regions), which has trended downward since the early 1990s, rebounds somewhat in the Reference case, primarily supplanting more expensive coal from Central Appalachia that currently is consumed at coal-fired power plants 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 addition, some of the growth in output from the Interior region results from increased lignite production in Texas and Louisiana. Total production of Appalachian coal declines from current levels, as output shifts from the extensively mined, higher cost reserves of Central Appalachia to lower cost supplies from the Interior region and the northern part of the Appalachian basin.

Long-term outlook for coal production varies considerably across cases

Figure 89. U.S. coal production in six cases, 2008, 2020, and 2035 (quadrillion Btu)



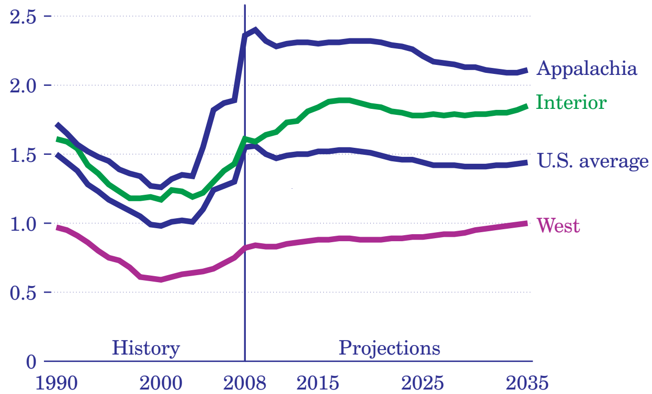
U.S. coal production varies across the *AEO2010* cases, reflecting different assumptions about the costs of producing and transporting coal, the outlook for economic growth, and the outlook for world oil prices (Figure 89). In addition, although they are not shown in the figure, alternative assumptions about restrictions on GHG emissions could have even larger impacts on coal production over the projection period.

Assumptions about economic growth primarily affect the projections for overall electricity demand, which in turn determine the need for coal-fired generation. In contrast, assumptions about the costs of producing and transporting coal primarily affect the choice of technologies for electricity generation, with coal capturing a larger share of the U.S. electricity market in the Low Coal Cost case and a smaller share in the High Coal Cost case. In the High Oil Price case, higher oil prices stimulate the demand for coal-based synthetic liquids, leading to a substantial expansion of coal use at CTL plants. Production of coal-based synthetic liquids totals 919,000 barrels per day in 2035 in the High Oil Price case, nearly four times more than in the Reference case.

Coal production in the Reference case increases by 6 percent from 2008 to 2035, whereas the alternative cases show changes ranging from a decrease of 7 percent to an increase of 16 percent. In the earlier years of the projection, from 2008 to 2020, variations in coal production across the cases are smaller, ranging from a decline of 4 percent to an increase of 4 percent, primarily reflecting the smaller changes in overall energy demand over the shorter time frame.

Minemouth coal prices in the Western and Interior regions rise

Figure 90. Average annual minemouth coal prices by region, 1990-2035 (2008 dollars per million Btu)



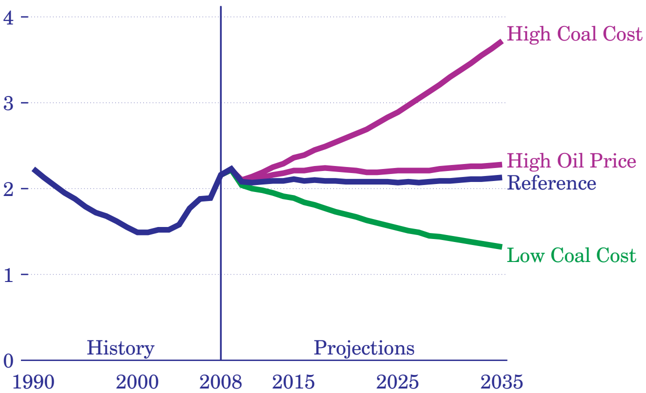
In the Western and Interior coal supply regions, slight declines in mining productivity, combined with projections of increasing production, result in higher minemouth prices, with average annual price growth of 0.5 percent and 0.7 percent, respectively, in the two regions from 2008 to 2035 (Figure 90).

In contrast, after peaking in 2009, the average minemouth price for Appalachian coal declines by 0.5 percent per year through 2035, as a result of falling demand for the region's coal and a shift to lower cost production in the northern part of the Appalachian basin. Recent jumps in the average price of Appalachian coal, from $1.26 per million Btu in 2000 to $2.36 per million Btu in 2008, were in part a result of significant declines in mining productivity during the period. The price increases have substantially reduced the competitiveness of Appalachian coal with coal from the other producing regions.

In the Reference case, average U.S. minemouth coal prices are roughly flat to slightly down overall, from $1.55 per million Btu in 2008 to $1.51 in 2020 and $1.44 in 2035—a decline of 0.3 percent per year over the entire period but starting from an unusual rise in 2008. Sizable increases in prices from 2000 to 2008 averaged 5.9 percent per year, and sharper declines from 1990 to 2000 averaged 4.2 percent per year. The moderation of coal prices in the projection results from a variety of factors, including a shift in production from Appalachia to the Interior and Western regions, which have lower costs of production, and a relatively flat outlook for coal mining productivity, which in recent years has been declining at a substantial pace in all the major coal-producing regions.

Substantial changes in coal prices have moderate effects on demand

Figure 91. Average annual delivered coal prices in four cases, 1990-2035 (2008 dollars per million Btu)



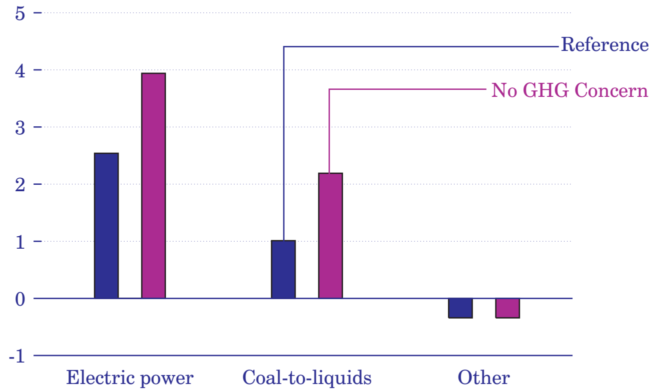
Alternative assumptions for coal mining and transportation costs affect delivered coal prices and demand. Two Coal Cost cases developed for *AEO2010* examine the impacts on U.S. coal markets of alternative assumptions about mining productivity, labor costs, mine equipment costs, and coal transportation rates (Figure 91). Although alternative assumptions about economic growth and world oil prices lead to some variations in the price paths for coal, the differences from the Reference case are relatively small in those cases.

In the High Coal Cost case, the average delivered coal price is $3.72 per million Btu (2008 dollars) in 2035—74 percent higher than in the Reference case. Because the higher coal prices result in switching from coal to natural gas and renewables in the electricity sector, U.S. coal consumption in 2035 is 7 percent (1.8 quadrillion Btu) lower in the High Coal Cost case than in the Reference case. In the Low Coal Cost case, delivered coal prices in 2035 average $1.32 per million Btu—38 percent lower than in the Reference case—and total coal consumption is 6 percent (1.5 quadrillion Btu) higher than in the Reference case.

Because the Economic Growth and Oil Price cases use the Reference case assumptions for coal mining and rail transportation costs, they show smaller variations in average delivered coal prices than do the two coal cost cases. Differences in coal price projections in the Economic Growth and Oil Price cases result mainly from higher and lower levels of demand for coal. In the Oil Price cases, higher and lower fuel costs for both coal producers and railroads also contribute to the slight variations in coal prices.

Long-term outlook for coal is shaped by concerns about GHG legislation

Figure 92. Change in U.S. coal consumption by end use in two cases, 2008-2035 (quadrillion Btu)

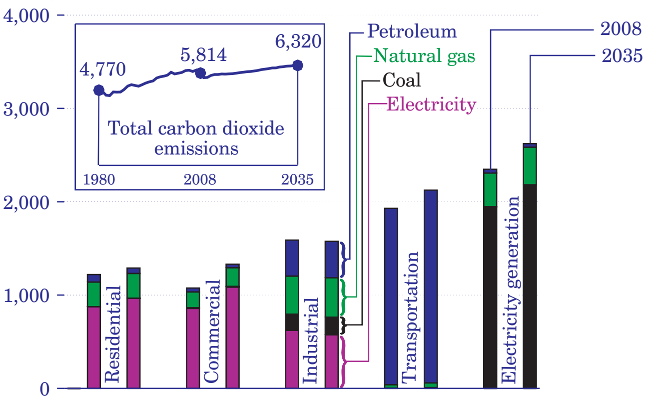


In the *AEO2010* Reference case, the cost of capital for investments in GHG-intensive technologies, including CTL plants and coal-fired power plants without CCS, is increased by 3 percentage points to reflect the behavior of utilities, other energy companies, and regulators concerning the possible enactment of GHG legislation which could mandate that owners purchase allowances, invest in CCS, or invest in other projects to offset their emissions in the future. A No GHG Concern case, in which the additional 3 percentage points for GHG-intensive technologies is removed, is used to evaluate the impact on energy investments.

In the No GHG Concern case, coal use for both electricity generation and production of coal-based synthetic liquids is considerably higher than in the Reference case (Figure 92), and 65 gigawatts of new coal-fired generating capacity is added between 2009 and 2035, as compared with 31 gigawatts in the Reference case. As a result, additions of both natural gas and renewable generating capacity are somewhat lower in the No GHG Concern case than in the Reference case. The production of coal-based synthetic liquids is also higher in the No GHG Concern case, at 525,000 barrels per day in 2035, compared with 243,000 barrels per day in the Reference case. CO_2 emissions increase to 6,488 million metric tons in 2035 in the No GHG Concern case, about 3 percent higher than in the Reference case and 12 percent higher than in 2008.

Growth of carbon dioxide emissions slows in the projections

Figure 93. Carbon dioxide emissions by sector and fuel, 2008 and 2035 (million metric tons)



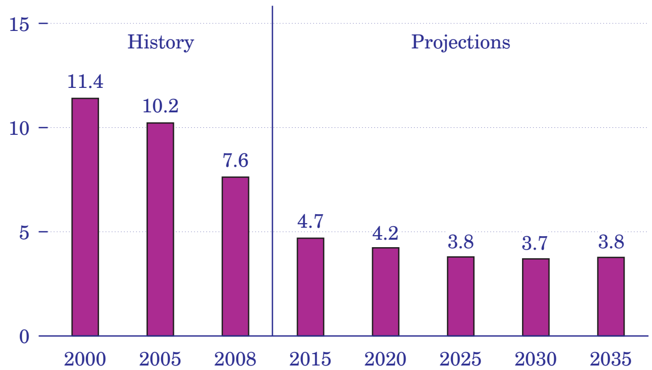
Federal and State energy policies recently enacted will stimulate increased use of renewable technologies and efficiency improvements in the future, slowing the growth of energy-related CO_2 emissions through 2035. In the Reference case, emissions do not exceed pre-recession 2007 levels until 2025. In 2035, energy-related CO_2 emissions total 6,320 million metric tons, about 6 percent higher than in 2007 and 9 percent higher than in 2008 (Figure 93). On average, emissions in the Reference case grow by 0.3 percent per year from 2008 to 2035, compared with 0.8 percent per year from 1980 to 2008.

Shares of the fossil fuels responsible for energy-related CO_2 emissions—coal, natural gas, and petroleum—do not vary substantially from 2008 to 2035. Petroleum, used mainly in the transportation sector, remains the largest source of CO_2 emissions, accounting for 42 percent of the total in 2008 and 41 percent in 2035. CAFE standards and RFS requirements reduce consumption and slow the growth of CO_2 emissions from petroleum. The coal share of CO_2 emissions rises from 37 percent in 2008 to 38 percent in 2035; the natural gas share is stable at 21 percent.

In 2008, 41 percent of total CO_2 emissions came from electricity generation. With its high carbon content and 48-percent share of generation, coal accounted for 82 percent of power sector CO_2 emissions. Given the uncertainty over future GHG regulations, higher capital costs for coal-fired technologies, and new RPS programs in many States, coal's share of generation falls to 44 percent in 2035. In addition, higher fuel costs and improved efficiency slow the overall growth of electricity demand and associated emissions.

Sulfur dioxide emissions decrease due to the Clean Air Interstate Rule

Figure 94. Sulfur dioxide emissions from electricity generation, 2000-2035 (million short tons)



In December 2008, the U.S. Court of Appeals for the District of Columbia Circuit temporarily reinstated CAIR, which includes a cap-and-trade system for SO_2 and NO_x emissions. The decision also required the EPA to develop new rules to correct flaws cited in the Court's July 2008 ruling that vacated CAIR, but because *AEO2010* considers only current rules and regulations, the projections for SO_2 and NO_x emissions are based on the current version of CAIR.

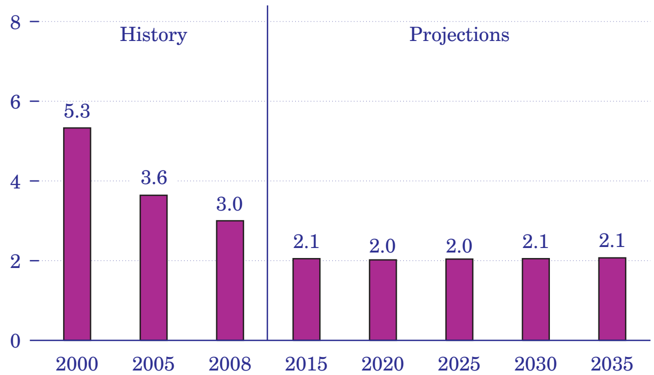
To comply with CAIR, SO_2 emissions in 2035 are 50 percent below the 2008 total (Figure 94). Reductions are achieved by more use of low-sulfur coal and flue gas desulfurization (FGD) scrubbers. From 2009 to 2035, coal-fired plants with about 81 gigawatts total capacity are retrofitted with scrubbers. Emissions vary from year to year, because CAIR allows utilities to bank unused allowances at the end of a year and use them in future years. In the 2030-2035 period, the amounts of banked allowances applied by utilities allow actual emissions to rise slightly.

SO_2 allowance prices increase from over $230 per ton in 2008 to almost $1,500 per ton in the later years of the projection. The price increase is a result of declining emissions caps, which lead to higher prices when allowances become scarce.

In addition to CAIR, implementation of a GHG emissions control policy could significantly reduce SO_2 emissions by forcing the retirement of older, less efficient coal-fired plants without FGD equipment.

Nitrogen oxide emissions also decline in the Reference case

Figure 95. Nitrogen oxide emissions from electricity generation, 2000-2035 (million short tons)



With the temporary reinstatement of CAIR, the annual NO_x emissions market officially began operating in 2009 (although provisions in the current CAIR are temporary until the EPA releases the court-ordered replacement rule). In *AEO2010,* NO_x emissions decline from 3.0 million short tons in 2008 to 2.0 million short tons in 2017, then rise slowly after 2018, when more banked allowances are used to meet the cap (Figure 95).

To reduce NO_x emissions, coal-fired power plants can be retrofitted with selective catalytic converter (SCR), selective noncatalytic converter, or low-NO_x burner technologies. In the Reference case, 168 gigawatts of total capacity is retrofitted with one or another of the three technologies. The amounts differ in the High and Low Economic Growth cases. Higher economic growth increases demand for electricity, and more plants are retrofitted. Lower growth has the opposite effect. In 2035, the NO_x allowance price, which is $3,268 per ton in the Reference case, is higher in High Economic Growth case (because more investment is required to comply with the cap) and lower in the Low Economic Growth Case, where demand for electricity is lower.

At the beginning of 2009, the EPA introduced an annual market for NO_x emissions to complement the existing seasonal market. So far, allowance prices in the annual market have been significantly higher than in the seasonal market, suggesting that the annual program may be more binding.

78. The National Bureau of Economic Research defines a recession as “a significant decline in economic activity spread across the economy, lasting more than a few months, normally visible in real GDP, real income, employment, industrial production, and wholesale-retail sales.” However, the shorthand version of a recession is often given as two consecutive quarters of negative growth in GDP. In December 2008, the National Bureau of Economic Research declared that the United States had entered a recession in December 2007.
79. The industrial sector includes manufacturing, agriculture, construction, and mining. The energy-intensive manufacturing sectors include food, paper, bulk chemicals, petroleum refining, glass, cement, steel, and aluminum.
80. Air-Conditioning, Heating, and Refrigeration Institute, “Agreement on Legislative and Regulatory Strategy for Amending Federal Energy Efficiency Standards, Test Procedures, Metrics and Building Code Provisions for Residential Central Air Conditioners, Heat Pumps, Weatherized and Non-Weatherized Furnaces and Related Matters” (October 13, 2009), web site http://www.ahrinet.org/Admin/Pages/Util/ShowDoc.aspx?doc=1635.
81. 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.
82. The factors that influence decisionmaking on capacity additions include electricity demand growth, the need to replace inefficient plants, the costs and operating efficiencies of different generation options, fuel prices, State RPS programs, and the availability of Federal tax credits for some technologies.
83. 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.
84. Detailed qualifications for each of the 35 State programs represented in the AEO2010 modeling include eligible technologies, funding limits, and penalties for noncompliance.
85. For example, drilling permits are not currently being issued in the State of New York, where concerns have been raised about potential risks to drinking water supplies.
86. Leasing in the Eastern Gulf of Mexico is restricted until 2022 under the Gulf of Mexico Energy Security Act of 2006.
87. One gallon of ethanol is equal to 0.65 gallon of regular gasoline.
88. The Motiva plant in Port Arthur, TX, and the Marathon project in Garyville, LA.

Comparison With Other Projections

Comparison with Other Projections

Only IHS Global Insights, Inc. (IHSGI) produces a comprehensive energy projection with a time horizon similar to that of *AEO2010*. 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 *AEO2010* projections.

Economic growth

Projections of the average annual growth rate of real GDP in the United States from 2008 to 2018 range from 2.1 percent to 2.8 percent (Table 9). In the *AEO2010* Reference case, real GDP grows by an average of 2.2 percent per year over the period, lower than projected by the Office of Management and Budget (OMB), the Congressional Budget Office (CBO), the Social Security Administration (SSA), and the Bureau of Labor Statistics (BLS)—although none of those projections has been updated since August 2009. The *AEO2010* projection is similar to the IHSGI projection and slightly higher than projections 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 2008 to 2018.

The range of GDP growth rates is wider for the recovery period from 2018 to 2030, with projections ranging from 2.2 to 2.7 percent per year. Uncertainty about the timing and speed of recovery from the current recession contributes to the wide range of projections over the 2018-2030 period. The 2.7-percent average annual GDP growth rate in the *AEO2010* Reference case from 2018 to 2030 is on the higher side of the estimates but similar to the IHSGI projection. SSA, the International Energy Agency (IEA), and INFORUM project lower growth, as a result of their lower projections for labor productivity. *AEO2010* projects productivity increases averaging 2.1 percent per year from 2018 to 2030, as compared with the SSA and INFORUM projections of 1.7 and 1.6 percent per year, respectively, over the same period.

There are few public or private projections of GDP growth for the United States that extend to 2035. The *AEO2010* Reference case projects 2.4-percent average annual GDP growth, consistent with the trends in labor force and productivity growth. IHSGI projects GDP growth averaging 2.5 percent per year from 2008 to 2035, and INFORUM projects an average of 2.3 percent from 2008 to 2030 (the last year of the INFORUM projection). Both *AEO2010* and IHSGI project higher growth rates for productivity and labor force growth than does INFORUM.

Table 9. Projections of average annual economic growth rates, 2008-2035

	Average annual percentage growth rates		
Projection	**2008-2018**	**2018-2030**	**2030-2035**
AEO2009 (Reference case)	2.2	2.6	–
AEO2010 (Reference case)	2.2	2.7	2.4
IHSGI (May 2009)	2.2	2.7	2.5
OMB (July 2009) [a]	2.8	–	–
CBO (August 2009) [a]	2.5	–	–
INFORUM (December 2009)	2.1	2.4	–
SSA (May 2009)	2.3	2.1	2.2
BLS (December 2009) [a]	2.4	–	–
IEA (2009) [b]	1.8	2.2	–
Blue Chip Consensus (March 2009)	2.2	–	–

[a]OMB and CBO projections end in 2019; BLS projection ends in 2018.
[b]IEA published U.S. growth rates for 2007-2015 (1.8 percent), 2015-2030 (2.2 percent), and 2007-2030 (2.1 percent).
– = not reported.

World oil prices

In the *AEO2010* Reference case, world oil prices rise from current levels to approximately $95 per barrel in 2015 and $108 per barrel in 2020 (Table 10). After 2020, prices increase slowly to $133 per barrel in 2035. The price trend is slightly lower than in last year's (*AEO2009*) Reference 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 and long term. Most of the projections show prices rising throughout the entire period. The projections for world oil prices in 2030 range from $65 per barrel to $124 per barrel. The range of the other projections is encompassed in

Table 10. Projections of world oil prices, 2015-2035 (2008 dollars per barrel)

Projection	2015	2020	2025	2030	2035
AEO2009 (Reference case)	112.91	117.99	124.62	133.29	–
AEO2010 (Reference case)	94.52	108.28	115.09	123.50	133.22
INFORUM	92.50	107.98	109.74	116.81	–
DB	93.18	105.48	114.65	121.16	125.42
IHSGI	85.07	81.93	74.86	77.27	80.03
IEA (Reference)	–	100.00	–	115.00	–
EVA	80.35	84.45	90.98	100.45	–
SEER (Business-as-Usual)	79.20	74.31	69.73	65.43	–
SEER (Multi-Dimensional)	99.03	101.52	105.81	113.91	–

– = not reported.

the range of the *AEO2010* Low and High Oil Price cases: from $52 per barrel to $204 per barrel in 2030 and from $51 per barrel to $210 per barrel in 2035.

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 West Texas Intermediate (WTI) prices that are widely cited as a proxy for world oil prices in the trade press. Deutsche Bank (DB), IHSGI, Energy Ventures Analysis, Inc. (EVA), and Strategic Energy & Economic Research, Inc. (SEER) report prices in WTI terms. IEA's *World Energy Outlook 2009* expresses prices as the IEA crude oil import price; INFORUM expresses prices as the average U.S. imported refiner acquisition cost of crude oil.

Total energy consumption

Two of the projections, IHSGI and INFORUM, feature energy consumption by sector (although the INFORUM projection does not include data for 2008 and does not extend to 2035). Energy prices in the IHSGI projection are lower than those in the *AEO2010* Reference case. Prices in the INFORUM projections for crude oil, natural gas, and coal also are higher than in *AEO2010*, but electricity prices in the end-use sectors are at the same level (industrial and commercial) or lower (residential) than in the *AEO2010* Reference case. Both IHSGI and INFORUM project slower growth in energy consumption than in the *AEO2010* Reference case (Table 11). Neither IHSGI nor INFORUM projects the introduction of Fischer-Tropsch fuels, nor do they include an accounting for the difference between the energy contained in biofuels and the energy contained in the biomass feedstock used in their production. When the *AEO2010* projections are adjusted for those two items (about 2.3 quadrillion Btu in 2030 and 3.1 quadrillion Btu in 2035), energy consumption in 2030 in the *AEO2010* Reference case is similar to that in the INFORUM projection, with differences of about 0.7 quadrillion Btu (lower) in the residential sector and about 0.7 quadrillion Btu (higher) in the electric power sector. For the residential sector, about one-half of the difference between the INFORUM and *AEO2010* Reference case projections is related to electricity consumption: INFORUM shows lower residential electricity prices but similar electricity prices in the industrial and commercial sectors. Total natural gas demand in the INFORUM projection is similar to that in the *AEO2010* Reference case, despite natural gas prices that are 50 to 80 cents per thousand cubic feet higher than in the *AEO2010* Reference case in 2020, 2025, and 2030.

Energy prices in the IHSGI projection generally are lower than those in the *AEO2010* Reference case. In the IHSGI projection for 2035, average natural gas wellhead prices are $2.20 per thousand cubic feet lower, average delivered electricity prices are 7 mills per kilowatthour lower, coal prices to the electric power sector are about $0.20 per million Btu lower,

Table 11. Projections of energy consumption by sector, 2007-2035 (quadrillion Btu)

	2007			2008			2030			2035		
Sector	*AEO-2010*	IN-FORUM	IHSGI	*AEO-2010*	IN-FORUM	IHSGI	*AEO-2010*	IN-FORUM	IHSGI	*AEO-2010*	IN-FORUM	IHSGI
Residential	11.3	11.3	10.8	11.3	–	10.9	11.9	12.6	11.8	12.1	–	11.9
Commercial	8.4	8.4	8.4	8.6	–	8.6	10.5	10.6	9.9	11.0	–	10.0
Industrial	25.2	–	–	24.8	–	–	26.1	–	–	26.7	–	–
Industrial excluding losses [a]	24.8	25.2	23.0	23.8	–	22.0	23.8	23.9	22.8	23.6	–	23.2
Transportation	29.0	28.9	28.6	27.8	–	27.3	31.3	31.0	29.1	32.5	–	30.6
Electric power	40.6	40.6	42.1	40.2	–	41.8	46.6	45.8	48.6	48.1	–	49.0
Less: electricity purchases [b]	12.8	12.8	12.8	12.7	–	12.8	15.3	15.3	15.8	15.9	–	16.3
Total primary energy	**101.7**	–	–	**100.1**	–	–	**111.2**	–	–	**114.5**	–	–
Total primary energy excluding industrial losses [a]	**101.2**	**101.7**	**100.1**	**99.1**	–	**97.8**	**108.8**	**108.7**	**106.4**	**111.4**	–	**108.5**

– = not reported.
[a]Losses in CTL and biofuel production.
[b]Energy consumption in the end-use sectors includes electricity purchases from the electric power sector, which must be subtracted to avoid double counting in the derivation of total primary energy consumption.

and light sweet crude oil prices are more than $50 per barrel lower than in the *AEO2010* projection. When the energy contained in biofuels and biomass feedstocks (which is not included in the IHSGI projection) is subtracted from the *AEO2010* Reference case projections, overall demand is about 3 quadrillion Btu lower in the IHSGI projection, transportation sector demand is about 2 quadrillion Btu lower, commercial sector demand (mostly for natural gas) is about 1 quadrillion Btu lower, and there are smaller differences in the industrial and residential sectors that more than offset the difference of about 1 quadrillion Btu between the higher IHSGI projection and the *AEO2010* Reference case projection for energy consumption in the electric power sector.

Electricity

Table 12 provides a summary of results from the *AEO2010* Reference case and compares them with other projections. For 2015, electricity sales range from a low of 3,870 billion kilowatthours in *AEO2010* to a high of 3,998 billion kilowatthours in the IHSGI projection. IHSGI shows higher sales in the residential and commercial sectors and slightly lower sales in the industrial sector. For 2035, electricity sales in the IHSGI projection are 4,734 billion kilowatthours, somewhat higher than the 4,660 billion kilowatthours in *AEO2010*. IHSGI projects higher residential and industrial sales and lower commercial sales of electricity in 2035.

The *AEO2010* Reference case shows declining real electricity prices after 2008, with rising prices near the end of the period, based on projected increases in fuel costs for generation and capital expenditures for construction of new capacity. The higher fossil fuel prices and capital expenditures in the *AEO2010* projection result in an increase in the average electricity price, from 8.9 cents per kilowatthour in 2015 to 10.2 cents per kilowatthour in 2035. IHSGI shows electricity prices declining from 2015 to 2035.

Total generation and imports of electricity in 2015 are higher in the IHSGI projection than in the *AEO-2010* Reference case. The requirements for generating capacity are driven by growth in electricity sales and the need to replace existing units that are uneconomical or are being retired for various reasons. Consistent with its projections of electricity sales, IHSGI shows higher growth in generation and imports through 2015 in comparison with the *AEO2010* Reference case. For 2035, total generation and imports are slightly lower in the IHSGI projection than in *AEO2010*. The two projections for nuclear power are similar, but those for generation from coal, oil, hydroelectric/other, and electricity imports all are lower, and the projection for natural gas is higher in the IHSGI projections than in the *AEO2010* Reference case.

The projections for generating capability in 2015 range from 1,032 gigawatts for IHSGI to 1,124 gigawatts for EVA, which shows more oil-fired and natural-gas-fired capacity than in the other projections. The IHSGI projections for hydroelectric/other capacity are lower than those from EVA and the *AEO2010* Reference case. The IHSGI and *AEO2010* projections of generating capability in 2035 are similar, except that IHSGI expects much less oil- and natural-gas-fired capacity than is projected in *AEO2010*. The *AEO2010* projection includes 4.0 gigawatts of uprates for nuclear capacity and expects all existing nuclear units to continue operating through 2035, based on the assumption that they will apply for and receive operating license renewals, including, in some cases, a second 20-year extension after they reach 60 years of operation. *AEO2010* also includes a second unit in 2014 at the Watts Bar site, where construction of a partially completed reactor was halted in 1988.

Environmental regulations are important determinants in the selection of electricity generation technologies. The *AEO2009* Reference case did not include the SO_2 and NO_x cap-and-trade programs for power plants called for in the EPA's CAIR, because the Circuit Court for the District of Columbia had vacated CAIR in a July 2008 ruling. On December 23, 2008, the Court temporarily reinstated the rule, however, and it is represented in the *AEO2010* Reference case. *AEO2010 does not* include the CAMR regulations, which were voided by the U.S. Court of Appeals in February 2008. Also, because *AEO2010* includes only current laws and regulations, it does not assume any cap or tax on CO_2 emissions. Restrictions on CO_2 emissions could change the mix of technologies used to generate electricity.

Natural gas

The variation among projections of natural gas consumption, production, imports, and prices (Table 13) can be significant. This variation results from differences among the assumptions that underlie the different projection. For example, the *AEO2010* Reference case generally assumes that current laws

Table 12. Comparison of electricity projections, 2015 and 2035 (billion kilowatthours, except where noted)

Projection	2008	*AEO2010* Reference case	Other projections	
			IHSGI	EVA
		2015		
Average end-use price (2008 cents per kilowatthour)	**9.8**	**8.9**	**9.6**	**–**
Residential	11.4	10.7	11.0	–
Commercial	10.4	9.1	10.1	–
Industrial	6.9	5.9	6.7	–
Total generation plus imports	**4,148**	**4,300**	**4,383**	**–**
Coal	1,995	2,037	2,070	–
Oil	45	46	46	–
Natural gas [a]	879	690	896	–
Nuclear	806	834	849	–
Hydroelectric/other [b]	391	672	504	–
Net imports	33	20	18	28
Electricity sales	**3,720**	**3,870**	**3,998**	**–**
Residential	1,379	1,400	1,512	–
Commercial/other [c]	1,359	1,473	1,517	–
Industrial	982	997	970	–
Capability, including CHP (gigawatts) [d]	**1,008**	**1,069**	**1,032**	**1,124**
Coal	312	325	323	323
Oil and natural gas	454	442	446	510
Nuclear	101	105	106	106
Hydroelectric/other	141	198	157	186
		2035		
Average end-use price (2008 cents per kilowatthour)	**9.8**	**10.2**	**9.5**	**–**
Residential	11.4	11.8	10.8	–
Commercial	10.4	10.4	9.9	–
Industrial	6.9	7.1	6.5	–
Total generation plus imports	**4,148**	**5,285**	**5,187**	**–**
Coal	1,995	2,305	2,244	–
Oil	45	49	32	–
Natural gas [a]	879	1,093	1,148	–
Nuclear	806	898	900	–
Hydroelectric/other [b]	391	915	851	–
Net imports	33	25	12	–
Electricity sales	**3,720**	**4,660**	**4,734**	**–**
Residential	1,379	1,707	1,809	–
Commercial/other [c]	1,359	1,937	1,831	–
Industrial	982	1,016	1,094	–
Capability, including CHP (gigawatts) [d]	**1,008**	**1,216**	**1,082**	**–**
Coal	312	337	334	–
Oil and natural gas	454	531	399	–
Nuclear	101	113	116	–
Hydroelectric/other	141	236	233	–

[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 CHP plants. IHSGI capacity is nameplate, excluding cogeneration plants.
– = not reported.
Sources: **2008 and *AEO2010:*** AEO2010 National Energy Modeling System, run AEO2010R.D111809A. **IHSGI:** IHS Global Insight, Inc., *2009 Energy Outlook* (Lexington, MA, September 2009). **EVA:** Energy Ventures Analysis, Inc., *FUELCAST: Long-Term Outlook* (February 2010).

and regulations will continue through the projection period as enacted, whereas some of the other projections assume the enactment of new public policy over the next 25 years. For example, the results of the Altos projection reflect the inclusion of carbon mitigation legislation.

All but two of the projections (Altos and EVA) show an initial decline and subsequent increase in natural gas consumption from 2008 levels, but they differ in terms of when, between 2015 and 2025, 2008 levels are regained. The INFORUM projection for 2015 is 1.2 to 2.1 trillion cubic feet lower than the others but recovers quickly by 2025. With the exception of the SEER projection, which shows a decline in natural gas consumption from 2025 to 2030, total natural gas consumption grows in spite of increasing prices in the later years of all the projections. Altos and EVA show natural gas consumption exceeding 2008 levels by 2010 and continuing to increase at much more rapid rates than in the other projections.

Table 13. Comparison of natural gas projections, 2015, 2025, and 2035 (trillion cubic feet, except where noted)

Projection	2008	*AEO2010* Reference case	Other projections					
			IHSGI	EVA	DB	SEER	Altos	INFORUM
					2015			
Dry gas production [a]	**20.56**	**19.29**	**22.63**	**24.47**	**19.29**	**20.01**	**19.19**	**19.71**
Net imports	**2.95**	**2.38**	**2.43**	**4.84**	**–**	**2.73**	**3.79**	**4.12**
Pipeline	2.65	1.29	1.62	2.65	–	1.83	0.47	–
LNG	0.30	1.09	0.81	2.19	3.48	0.90	3.32	–
Consumption	**23.25**	**21.74**	**22.63**	**24.84**	**–**	**22.80**	**24.18 [b]**	**18.86 [b]**
Residential	4.87	4.71	4.71	5.07	–	4.87	4.75	4.76
Commercial	3.12	3.23	3.05	3.21	–	3.14	3.18	3.16
Industrial [c]	6.65	6.88	6.24	6.84	–	6.23	6.41	6.35
Electricity generators [d]	6.66	5.18	6.74	7.62	–	6.73	9.83	4.60
Other [e]	1.95	1.73	1.90	2.09	–	1.84	–	–
Lower 48 wellhead price (2008 dollars per thousand cubic feet) [f]	**8.07**	**5.70**	**5.73**	**6.40**	**5.77**	**5.34**	**6.06**	**–**
End-use prices (2008 dollars per thousand cubic feet)								
Residential	13.87	11.89	12.15	–	–	12.26	–	–
Commercial	12.29	10.28	10.51	–	–	11.08	–	–
Industrial [g]	9.38	6.63	8.01	–	–	7.11	–	–
Electricity generators	9.34	6.24	6.44	–	–	6.70	–	–
					2025			
Dry gas production [a]	**20.56**	**21.31**	**21.91**	**24.41**	**20.63**	**22.30**	**27.23**	**20.93**
Net imports	**2.95**	**2.17**	**2.34**	**2.89**	**–**	**2.18**	**3.67**	**5.77**
Pipeline	2.65	0.89	1.42	2.52	–	1.25	-1.42	–
LNG	0.30	1.28	0.92	0.37	2.65	0.93	5.09	–
Consumption	**23.25**	**23.57**	**24.22**	**27.84**	**–**	**24.35**	**27.72 [b]**	**21.82 [b]**
Residential	4.87	4.89	4.62	5.16	–	4.90	4.85	4.86
Commercial	3.12	3.45	3.06	3.28	–	3.41	3.33	3.24
Industrial [c]	6.65	6.94	6.34	7.55	–	6.55	6.47	6.93
Electricity generators [d]	6.66	6.28	8.12	9.49	–	7.51	13.08	6.81
Other [e]	1.95	2.00	2.07	2.36	–	1.99	–	–
Lower 48 wellhead price (2008 dollars per thousand cubic feet) [f]	**8.07**	**6.35**	**5.87**	**7.31**	**8.42**	**5.90**	**7.01**	**–**
End-use prices (2008 dollars per thousand cubic feet)								
Residential	13.87	12.65	12.08	–	–	12.96	–	–
Commercial	12.29	11.01	10.49	–	–	11.87	–	–
Industrial [g]	9.38	7.22	8.10	–	–	7.70	–	–
Electricity generators	9.34	6.94	6.57	–	–	8.87	–	–

– = not reported. See notes and sources at end of table.

For the residential and commercial sectors, natural gas consumption patterns are similar across the projections, with the exception of IHSGI, which shows a decline in residential consumption and commercial consumption that remains below the 2008 level through 2035. Excluding IHSGI, the average annual rate of growth in residential natural gas consumption from 2008 to 2025 ranges from almost no growth to 0.5 percent, and the average for commercial natural gas consumption varies from 0.2 percent (INFORUM) to 0.6 percent (*AEO2010*).

Three of the six projections (EVA, INFORUM, and the *AEO2010* Reference case) show industrial natural gas consumption returning to 2008 levels or higher by 2015. In the *AEO2010* projection, industrial natural gas consumption exceeds 2008 levels in 2015, because industrial natural gas prices are relatively low, and there is a significant increase in the use of natural gas at refineries for biofuel production. The *AEO2010* Reference case and EVA projections show the strongest short-term growth in industrial natural gas consumption, averaging 0.5 percent per year from 2008 to 2015.

The differences among the projections for natural gas consumption in the electric power sector can be attributed to two primary factors: assumptions about carbon mitigation legislation and assumptions about the costs and availability of hydroelectric and other renewable energy resources. The *AEO2010* Reference case and INFORUM projections are the lowest, and they are the only ones in which the sector's consumption of natural gas in 2015 is lower than in 2008 (in the *AEO2010* Reference case, as a result of slow growth in electricity demand, completion of planned new coal-fired capacity, and construction of new renewable capacity in response to incentives and RFS

Table 13. Comparison of natural gas projections, 2015, 2025, and 2035 (continued)
(trillion cubic feet, except where noted)

Projection	2008	*AEO2010* Reference case	Other projections					
			IHSGI	EVA	DB	SEER	Altos	INFORUM
		2035						
Dry gas production [a]	**20.56**	**23.27**	**23.02**	**–**	**18.44**	**–**	**32.72**	**–**
Net imports	**2.95**	**1.46**	**1.84**	**–**	**–**	**–**	**1.70**	**–**
Pipeline	2.65	0.64	0.92	–	–	–	-4.46	–
LNG	0.30	0.83	0.92	–	3.91	–	6.16	–
Consumption	**23.25**	**24.86**	**24.84**	**–**	**–**	**–**	**30.48** [b]	**–**
Residential	4.87	4.87	4.45	–	–	–	4.85	–
Commercial	3.12	3.69	3.05	–	–	–	3.50	–
Industrial [c]	6.65	6.72	6.37	–	–	–	6.42	–
Electricity generators [d]	6.66	7.42	8.81	–	–	–	15.72	–
Other [e]	1.95	2.17	2.16	–	–	–	–	–
Lower 48 wellhead price (2008 dollars per thousand cubic feet) [f]	**8.07**	**8.06**	**5.87**	**–**	**9.91**	**–**	**7.89**	**–**
End-use prices (2008 dollars per thousand cubic feet)								
Residential	13.87	14.82	11.85	–	–	–	–	–
Commercial	12.29	13.03	10.31	–	–	–	–	–
Industrial [g]	9.38	8.99	8.05	–	–	–	–	–
Electricity generators	9.34	8.69	6.54	–	–	–	–	–

– = not reported.
[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. [d]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. [e]Includes lease, plant, and pipeline fuel and fuel consumed in natural gas vehicles. [f]2008 wellhead natural gas price for SEER is $7.65 per thousand cubic feet. [g]The 2008 industrial natural gas price for IHSGI and SEER are $10.30 and $9.80 per thousand cubic feet, respectively.
Sources: **2008 and *AEO2010*:** AEO2010 National Energy Modeling System, run AEO2010R.D111809A. **IHSGI:** IHS Global Insight, Inc., *2009 U.S. Energy Outlook* (September 2009). **EVA:** Energy Ventures Analysis, Inc., *FUELCAST: Long-Term Outlook* (February 2010). **DB:** Deutsche Bank AG, e-mail from Adam Sieminski (November 3, 2009). **SEER:** Strategic Energy and Economic Research, Inc., "Natural Gas Outlook" (November 2009). **Altos:** Altos World Gas Trade Model (October 2009). **INFORUM:** INFORUM Base, e-mail from Douglas Meade (January 15, 2010).

programs at the State level). The highest level of natural gas consumption in the electric power sector is in the Altos projection, ranging from 29 percent to 114 percent above the other projections for 2015 and 38 percent to 108 percent above the others for 2025.

The natural gas supply projections from Altos and EVA differ significantly from the other projections, in part because of higher consumption levels. In addition, however, Altos also has a very different outlook for net pipeline imports of natural gas. Whereas the other projections show declines in pipeline imports, Altos has a more aggressive outlook, projecting that the United States will become a net exporter by 2020, and that U.S. pipeline exports will total 4.5 trillion cubic feet in 2035. As a result, the requirements for additional supply from domestic production and LNG imports in the Altos projection are significantly greater than those in the other projections.

Wellhead natural gas prices in the Altos projection are higher than those in the other projections, with the exception of DB, but the differences are not proportional to the differences in domestic production. Three of the seven projections (*AEO2010* Reference case, IHSGI, and SEER) present relatively similar outlooks for supply sources, with domestic production providing a growing percentage of total natural gas supply over the projection period (with very similar percentages). The *AEO2010* Reference case, IHSGI, and SEER also show a decline in net pipeline imports of natural gas, but net imports remain positive over the entire projection period, with growth in LNG imports to about 1 trillion cubic feet. The same three projections also show generally lower natural gas prices than the others, indicating a generally more optimistic view of domestic natural gas supply potential. In contrast, EVA, DB, and Altos project greater reliance on net LNG imports, at 2.2 trillion cubic feet per year and above. The DB wellhead natural gas prices are the highest among the projections shown in Table 13, reflecting a more pessimistic view of the potential for future domestic natural gas production.

Price margins for delivered natural gas (defined as the difference between delivered and wellhead natural gas prices) reflect average transportation and delivery charges, as well as differences in what each sector pays for natural gas at the supply point. Only the *AEO2010* Reference case, IHSGI, and SEER include projections for delivered natural gas prices. For the residential and commercial sectors, IHSGI projects an increase in margins over their 2008 levels, followed by a decline. The *AEO2010* Reference case and SEER project continued increases in residential and commercial margins over the projection period. In the *AEO2010* Reference case, the increases result largely from a decline in natural gas consumption per customer, which increases the per-unit-equivalent charge for the fixed component of customers' gas bills.

End-use natural gas prices in the industrial sector are difficult to compare because of apparent definitional differences between the projections, which are obvious from a comparison of 2008 prices in the different projections. In the IHSGI and SEER projections, industrial natural gas prices in 2008 are, respectively, $0.93 and $0.43 (2008 dollars) per thousand cubic feet higher than in the *AEO2010* Reference case, implying some difference in the definition of industrial natural gas prices (the definitions were not available to EIA). The projected industrial margins remain relatively stable in the IHSGI, SEER, and *AEO2010* projections, but they differ significantly: the average industrial margins for IHSGI and SEER are $1.32 and $0.87 per thousand cubic feet higher, respectively, than the average industrial margin in the *AEO2010* Reference case.

The *AEO2010* Reference case and IHSGI margins for the electric power sector are more similar, with IHSGI showing slightly higher average margins consistent with the difference in the margins for 2008. In the SEER projections, natural gas margins for the electric power sector decline in the near term from their 2008 level of $1.60 per thousand cubic feet (2008 dollars), then increase rapidly after 2013, exceeding SEER's industrial margin after 2018 and climbing to $4.05 per thousand cubic feet in 2030. In the *AEO2010* Reference case and IHSGI projections, margins in the electric power sector also decline quickly after 2008, but they remain considerably lower than their 2008 levels, reaching a maximum of $0.64 per thousand cubic feet (2008 dollars) in 2029 in the *AEO2010* Reference case and $0.72 per thousand cubic feet (2008 dollars) in 2015 in the IHSGI projection.

Liquid fuels

In the *AEO2010* Reference case, the world oil price is assumed to be $95 per barrel in 2015, $115 in 2025, and $133 in 2035 (see Table 10). This price projection is similar to DB's price projection for WTI ($93 per barrel in 2015, $115 in 2025, and $125 in 2035). EVA, IHSGI, and Purvin and Gertz, Inc. (P&G) project much lower crude oil prices.

Table 14. Comparison of liquids projections, 2015, 2025, and 2035
(million barrels per day, except where noted)

Projection	2008	*AEO2010* Reference case	Other projections: IHSGI	EVA	DB	P&G	IEA
		2015					
Crude oil and NGL production	**6.75**	**7.54**	**6.50**	**8.14**	**6.60**	**6.11**	**–**
Crude oil	4.96	5.77	4.75	–	4.95	4.36	4.70
Natural gas liquids	1.78	1.77	1.75	–	1.65	1.75	–
Total net imports	**11.14**	**10.12**	**10.42**	**–**	**10.40**	**11.58**	**–**
Crude oil	9.75	8.88	9.68	–	–	11.80	–
Petroleum products	1.39	1.24	0.74	–	–	-0.22	–
Petroleum demand	**19.52**	**20.18**	**19.29**	**–**	**18.65**	**18.21**	**17.90**
Motor gasoline	8.99	9.37	8.56	–	8.97	8.96	–
Jet fuel	1.54	1.57	1.58	–	1.40	1.62	–
Distillate fuel	3.94	4.08	4.08	–	3.61	4.14	–
Residual fuel	0.62	0.66	0.61	–	0.54	0.57	–
Other	4.43	4.49	4.45	–	–	2.92	–
Net import share of petroleum demand (percent)	**62**	**57**	**54**	**–**	**–**	**64**	**–**
		2025					
Crude oil and NGL production	**6.75**	**7.87**	**5.76**	**7.16**	**5.39**	**4.86**	**–**
Crude oil	4.96	6.13	3.87	–	4.04	3.24	–
Natural gas liquids	1.78	1.74	1.90	–	1.35	1.62	–
Total net imports	**11.14**	**9.70**	**11.19**	**–**	**10.70**	**12.03**	**–**
Crude oil	9.75	8.60	10.57	–	–	12.30	–
Petroleum products	1.39	1.10	0.62	–	–	-0.27	–
Petroleum demand	**19.52**	**20.63**	**20.38**	**–**	**17.51**	**18.07**	**–**
Motor gasoline	8.99	9.32	7.80	–	8.32	7.79	–
Jet fuel	1.54	1.75	1.98	–	1.36	1.81	–
Distillate fuel	3.94	4.41	5.23	–	3.34	4.70	–
Residual fuel	0.62	0.66	0.61	–	0.50	0.58	–
Other	4.43	4.50	4.75	–	–	3.19	–
Net import share of petroleum demand (percent)	**62**	**55**	**55**	**–**	**–**	**67**	**–**
		2035					
Crude oil and NGL production	**6.75**	**8.11**	**5.06**	**–**	**4.29**	**–**	**–**
Crude oil	4.96	6.27	3.07	–	3.22	–	–
Natural gas liquids	1.78	1.83	1.99	–	1.07	–	–
Total net imports	**11.14**	**9.66**	**13.31**	**–**	**9.50**	**–**	**–**
Crude oil	9.75	8.65	11.72	–	–	–	–
Petroleum products	1.39	1.02	1.59	–	–	–	–
Petroleum demand	**19.52**	**20.86**	**21.81**	**–**	**15.18**	**–**	**–**
Motor gasoline	8.99	9.06	7.33	–	6.80	–	–
Jet fuel	1.54	1.84	2.29	–	1.29	–	–
Distillate fuel	3.94	4.91	6.56	–	2.95	–	–
Residual fuel	0.62	0.67	0.59	–	0.44	–	–
Other	4.43	4.37	5.05	–	–	–	–
Net import share of petroleum demand (percent)	**62**	**54**	**61**	**–**	**–**	**–**	**–**

– = not reported.
Sources: **2008 and *AEO2010:*** AEO2010 National Energy Modeling System, run AEO2010R.D111809A. **IHSGI:** IHS Global Insight, Inc., *2009 Energy Outlook* (Lexington, MA, September 2009). **EVA:** Energy Ventures Analysis, Inc., *FUELCAST: Long-Term Outlook* (February 2010). **DB:** Deutsche Bank AG, e-mail from Adam Sieminski (November 3, 2009). **P&G:** Purvin and Gertz, Inc., 2009 Global Petroleum Market Outlook, Vol. 2, Table III-2 (April 2009). **IEA:** International Energy Agency, *World Energy Outlook 2009* (Paris, France, November 2009), Table 1.4.

A major difference between the *AEO2010* Reference case and all but the EVA projection is that the *AEO2010* projects much higher domestic crude oil production throughout the projection (Table 14). In addition, domestic production of crude oil increases gradually over time in the *AEO2010* projection, whereas all the other projections show rapid decreases in domestic production. As a consequence, the *AEO2010* Reference case shows lower net imports of crude oil.

Overall petroleum product demand in the *AEO2010* Reference case is similar to that in the IHSGI projection but higher than those in the EVA, DB, P&G, and IEA projections. The IHSGI projection shows a higher ratio of distillate to motor gasoline consumption than in the *AEO2010* Reference case, however, especially in 2035, implying more distillate use than in the *AEO2010* projection.

AEO2010, IHSGI, DB, and P&G all show motor gasoline demand decreasing in absolute terms. For *AEO2010*, the decline in motor gasoline demand is the result of increased efficiency, tighter CAFE standards, and increased use of ethanol. All four projections also show increasing ratios of distillate fuel to motor gasoline consumption.

In the *AEO2010* Reference case, demand for jet fuel increases at a gradual pace, averaging 0.8 percent per year from 2015 to 2035. In the IHSGI projection, jet fuel demand is at the same level as in the *AEO2010* in 2015 but increases at a faster pace, averaging just under 1.9 percent per year from 2015 to 2035. In the DB projection, jet fuel demand gradually decreases over time, by 0.4 percent per year on average from 2015 to 2035.

Coal

The outlook for coal markets varies considerably across the projections compared in Table 15. 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 *AEO2010* Reference case, total U.S. coal consumption increases from 1,122 million tons (22.4 quadrillion Btu) in 2008 to 1,235 million tons (23.6 quadrillion Btu) in 2025 and 1,319 million tons (25.1 quadrillion Btu) in 2035. Total coal consumption also increases in the IEA projection, to 22.7 quadrillion Btu in 2025. Total coal consumption decreases in both the IHSGI and DB projections to 1,095 million tons and 21.9 quadrillion Btu, respectively, in 2025 and to 1,086 million tons and 20.8 quadrillion Btu, respectively, in 2035.

In the *AEO2010* projection, coal production increases from 1,172 million tons (23.9 quadrillion Btu) to 1,234 million tons (24.4 quadrillion Btu) in 2025 and to 1,285 million tons (25.2 quadrillion Btu) in 2035. INFORUM projects a larger increase in coal production, to 1,465 million tons in 2025. In the Wood Mackenzie Company (WM) projection, production (excluding coking coal) remains relatively constant, increasing to 1,180 million tons in 2025. In the IHSGI projection, coal production falls to 1,109 million tons in 2025 and 1,098 million tons in 2035.

U.S. coal exports decline from 82 million tons in 2008 to 48 million tons in 2025 in the *AEO2010* Reference case, and coal imports increase slightly from 32 million tons in 2008 to 34 million tons in 2025. In contrast to the other projections, *AEO2010* projects that the United States eventually will become a net importer of coal. U.S. coal exports fall to 33 million tons in 2035 in the *AEO2010* Reference case, and coal imports increase to 53 million tons. INFORUM projects an increase in exports to 161 million tons, as well as an increase in imports to 43 million tons, in 2025. In the WM projection, both exports and imports (excluding coking coal) fall to 26 million tons in 2025. IHSGI projects a decrease in exports to 49 million tons in 2025 and to 45 million tons in 2035, with little change in coal imports, which total 35 million tons in 2025 and 33 million tons in 2035.

Minemouth coal prices in the *AEO2010* Reference case decline from $31.26 per ton ($1.55 per million Btu) in 2008 to $28.19 per ton ($1.44 per million Btu) in 2025 and remain relatively constant thereafter, with a price of $28.10 per ton ($1.44 per million Btu) projected for 2035. In the IHSGI projection, the average minemouth coal price falls to $26.08 per ton in 2025 and $25.81 per ton in 2035. Both WM and INFORUM project slight decreases in minemouth coal prices, to $31.14 per ton and $30.91 per ton in 2025, respectively.

Table 15. Comparison of coal projections, 2015, 2025, and 2035 (million short tons, except where noted)

Projection	2008	*AEO2010* Reference case	Other projections				
			IHSGI	DB	IEA	WM	INFORUM
			2015				
Production	**1,172**	**1,155**	**1,141**	**–**	**–**	**1,149** [a]	**1,254**
Consumption by sector							
Electric power	1,042	1,044	1,042	–	–	–	–
Coke plants	22	20	21	–	–	–	–
Coal-to-liquids	0	21	–	–	–	–	–
Other industrial/buildings	58	56	57	–	–	–	–
Total	**1,122**	**1,141**	**1,120**	**23.0** [b]	**21.8** [b]	**–**	**–**
Net coal exports	**49**	**30**	**19**	**–**	**–**	**3** [a]	**65**
Exports	82	60	57	–	–	19 [a]	102
Imports	32	30	38	–	–	16 [a]	37
Minemouth price							
(2008 dollars per short ton)	31.26	30.38	27.26 [c]	–	–	27.42 [d]	31.15
(2008 dollars per million Btu)	1.55	1.52	1.32	–	–	1.37 [d]	–
Average delivered price to electricity generators							
(2008 dollars per short ton)	40.71	39.46	41.14 [c]	–	–	41.64 [d]	40.57
(2008 dollars per million Btu)	2.05	2.01	2.00	–	–	2.09 [d]	–
			2025				
Production	**1,172**	**1,234**	**1,109**	**–**	**–**	**1,180** [a]	**1,465**
Consumption by sector							
Electric power	1,042	1,116	1,021	–	–	–	–
Coke plants	22	19	20	–	–	–	–
Coal-to-liquids	0	44	–	–	–	–	–
Other industrial/buildings	58	56	54	–	–	–	–
Total	**1,122**	**1,235**	**1,095**	**21.9** [a]	**22.7** [b]	**–**	**–**
Net coal exports	**49**	**14**	**14**	**–**	**–**	**0** [a]	**118**
Exports	82	48	49	–	–	26 [a]	161
Imports	32	34	35	–	–	26 [a]	43
Minemouth price							
(2008 dollars per short ton)	31.26	28.19	26.08 [c]	–	–	31.14 [d]	30.91
(2008 dollars per million Btu)	1.55	1.44	1.27	–	–	1.57 [d]	–
Average delivered price to electricity generators							
(2008 dollars per short ton)	40.71	38.49	39.33 [c]	–	–	46.01 [d]	40.25
(2008 dollars per million Btu)	2.05	1.99	1.91	–	–	2.32 [d]	–

Btu = British thermal unit. – = not reported. See notes and sources at end of table.

Table 15. Comparison of coal projections, 2015, 2025, and 2035 (continued)
(million short tons, except where noted)

Projection	2008	*AEO2010* Reference case	Other projections				
			IHSGI	DB	IEA	WM	INFORUM
		2035					
Production	**1,172**	**1,285**	**1,098**	**–**	**–**	**–**	**–**
Consumption by sector							
Electric power	1,042	1,183	1,018	–	–	–	–
Coke plants	22	14	19	–	–	–	–
Coal-to-liquids	0	68					
Other industrial/buildings	58	54	49	–	–	–	–
Total	**1,122**	**1,319**	**1,086**	**20.8** [b]	**–**	**–**	**–**
Net coal exports	**49**	**-20**	**12**	**–**	**–**	**–**	**–**
Exports	82	33	45	–	–	–	–
Imports	32	53	33	–	–	–	–
Minemouth price							
(2008 dollars per short ton)	31.26	28.10	25.81 [c]	–	–	–	–
(2008 dollars per million Btu)	1.55	1.44	1.26	–	–	–	–
Average delivered price to electricity generators							
(2008 dollars per short ton)	40.71	40.74	39.02 [c]	–	–	–	–
(2008 dollars per million Btu)	2.05	2.09	1.90	–	–	–	–

Btu = British thermal unit. – = not reported.
[a]Excludes coking coal.
[b]Reported in quadrillion Btu.
[c]Imputed, using heat conversion factor implied by U.S. steam coal consumption figures for the electricity sector.
[d]Converted to 2008 dollars, using the *AEO2010* GDP inflator.
Sources: **2008 and *AEO2010:*** AEO2010 National Energy Modeling System, run AEO2010R.D111809A. **IHSGI:** IHS Global Insight, Inc., *2009 U.S. Energy Outlook* (September 2009). **DB:** Deutsche Bank AG, e-mail from Adam Sieminski (December 31, 2009). **IEA:** International Energy Agency, *World Energy Outlook 2009* (Paris, France, November 2009).**WM:** Wood Mackenzie Company, *Fall 2009 Long Term Outlook Base Case*. **INFORUM:** INFORUM Base, e-mail from Douglas Meade (January 15, 2010).

List of Acronyms

A.B.	Assembly Bill
ACESA	American Clean Energy and Security Act of 2009
AEO	*Annual Energy Outlook*
AEO2007	*Annual Energy Outlook 2007*
AEO2008	*Annual Energy Outlook 2008*
AEO2009	*Annual Energy Outlook 2009*
AEO2010	*Annual Energy Outlook 2010*
AFV	Alternative-fuel vehicle
ARRA	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
CHP	Combined heat and power
CNG	Compressed natural gas
CO_2	Carbon dioxide
CREB	Clean and Renewable Energy Bonds
CTL	Coal-to-liquids
CWA	Clean Water Act
DB	Deutsche Bank AG
DOE	U.S. Department of Energy
DOD	U.S. Department of Defense
E10	Fuel containing 10 percent ethanol and 90 percent gasoline by volume
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
EVA	Energy Ventures Analysis, Inc.
FEMP	Federal Energy Management Program
FFV	Flex-fuel vehicle
FGD	Flue gas desulfurization
GDP	Gross domestic product
GHG	Greenhouse gas
GSA	U.S. General Services Administration
GTL	Gas-to-liquids
GVWR	Gross vehicle weight rating
HDNGV	Heavy-duty natural gas vehicle
HEV	Hybrid electric vehicle
H.R.	House of Representatives
IEA	International Energy Agency
IECC	International Energy Conservation Code
IHSGI	IHS Global Insight
INFORUM	Interindustry Forecasting Project at the University of Maryland
ITC	Investment tax credit
LCFS	Low Carbon Fuel Standard (California)
LED	Light-emitting diode
LDV	Light-duty vehicle
LNG	Liquefied natural gas
LPG	Liquid petroleum gas
MHEV	Micro hybrid electric vehicle
mpg	Miles per gallon
MY	Model year
NEMS	National Energy Modeling System (EIA)
NERC	North American Electric Reliability Council
NGL	Natural gas liquids
NHTSA	National Highway Traffic Safety Administration
NO_x	Nitrogen oxide
NRC	U.S. Nuclear Regulatory Commission
O&M	Operation and maintenance
OMB	Office of Management and Budget
OPEC	Organization of the Petroleum Exporting Countries
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-40	PHEV designed to travel about 40 miles on battery power alone
PTC	Production tax credit
PV	Solar photovoltaic
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.
SO_2	Sulfur dioxide
SSA	Social Security Administration
SUV	Sport utility vehicle
TAPS	Trans Alaska Pipeline System
TV	Television
VIUS	Vehicle Inventory and Use Summary
VMT	Vehicle miles traveled
WCI	Western Climate Initiative
WM	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 average fleet-wide fuel economy and CO2-equivalent emissions compliance levels, model years 2012-2016: Environmental Protection Agency and National Highway Traffic Safety Administration, *Light-Duty Vehicle Greenhouse Gas Emission Standards and Corporate Average Fuel Economy Standards; Final Rule*, 40 CFR, Parts 85, 86, and 600, 49 CFR Parts 531, 533, 537, and 538 [EPA-HQ-OAR-2009-0472; FRL-_8959-4; NHTSA-2009-0059], RIN 2060-AP58; RIN 2127-AK50 (Washington, DC, April 2010), web site www.nhtsa.dot.gov/staticfiles/DOT/NHTSA/Rulemaking/Rules/AssociatedFiles/CAFE-GHG-MY_2012-2016_Final_Rule_v2. pdf.

Table 2. Renewable portfolio standards in the 30 States with current mandates: U.S. 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 September 1, 2009.

Table 3. Key analyses from "Issues in Focus" in recent *AEOs*: U.S. Energy Information Administration, *Annual Energy Outlook 2009*, DOE/EIA-0383(2009) (Washington, DC, March 2009); U.S. Energy Information Administration, *Annual Energy Outlook 2008*, DOE/EIA-0383(2008) (Washington, DC, June 2008); U.S. Energy Information Administration, *Annual Energy Outlook 2007*, DOE/EIA-0383(2007) (Washington, DC, February 2007).

Table 4. Average annual increases in economic output, population, and energy consumption indicators in the buildings, industrial, and transportation sectors, 2008-2035: AEO2010 National Energy Modeling System, run AEO2010R.D111809A.

Table 5. Maximum market potential for natural gas heavy-duty vehicles in Base Market and Expanded Market cases: U.S. Energy Information Administration, Office of Integrated Analysis and Forecasting using data from U.S. Department of Commerce, Bureau of Census, Vehicle Inventory and Use Survey, EC02TV (Washington, DC, December 2004).

Table 6. Levelized capital costs for natural gas fueling stations with and without assumed tax credits: U.S. Energy Information Administration, Office of Integrated Analysis and Forecasting.

Table 7. Natural gas prices, supply, and consumption in four cases, 2035: AEO2010 National Energy Modeling System, runs AEO2010R.D111809A, NOSHALE.D021110A, NOLOPERM.D020510A, and HISHALE.D012210A.

Table 8. Comparison of key projections in the Reference and Nuclear 60-Year Life cases: AEO2010 National Energy Modeling System, runs AEO2010R.D111809A and NUCRET.D123009A.

Table 9. Projections of average annual economic growth rates, 2008-2035: *AEO2009* (Reference case): AEO2009 National Energy Modeling System, run AEO2009.D030208F. ***AEO2010* (Reference case):** AEO2010 National Energy Modeling System, run AEO2010R.D111809A. **IHSGI (May 2009):** IHS/Global Insight, Inc., *U.S. Macroeconomic 30 Year Trend Forecast* (Lexington, MA, November 2009). **OMB (July 2009):** Office of Management and Budget, *Mid-Session Review, Budget of the United States Government Fiscal Year 2009* (Washington, DC, June 2008). **CBO (August 2009):** Congressional Budget Office, *The Budget and Economic Outlook* (Washington, DC, January 2009) **INFORUM (December 2009):** INFORUM, email from Jeff Werling (December 8, 2008). **SSA (May 2009):** Social Security Administration, *OASDI Trustees Report* (Washington, DC, May 2008). **BLS (December 2009):** Bureau of Labor Statistics, *Macro Projections 2007*. **IEA (2009):** International Energy Agency, *World Energy Outlook 2008* (Paris, France, September 2008). **Blue Chip Consensus (March 2009):** *Blue Chip Economic Indicators* (Aspen Publishers, March 10, 2008).

Table 10. Projections of world oil prices, 2015-2035: *AEO2009* (Reference case): AEO2009 National Energy Modeling System, run AEO2009.D030208F. ***AEO2010* (Reference case):** AEO2010 National Energy Modeling System, run AEO2010R.D111809A. **DB:** Deutsche Bank AG, e-mail from Adam Sieminski (November 4, 2008). **IHSGI:** IHS/Global Insight, Inc., *U.S. Energy Outlook* (Lexington, MA, September 2008). **IEA (reference):** International Energy Agency, *World Energy Outlook 2008* (Paris, France, September 2008), Reference Scenario. **IER:** Institute of Energy Economics and the Rational Use of Energy at the University of Stuttgart, e-mail from Markus Blesl (December 4, 2008). **EVA:** Energy Ventures Analysis, Inc., e-mail from Roger Avalos (January 7, 2009). **SEER:** Strategic Energy and Economic Research, Inc., e-mail from Ron Denhardt (February 6, 2009).

Table 11. Projections of energy consumption by sector, 2007-2035: *AEO2010*: AEO2010 National Energy Modeling System, run AEO2010R.D111809A. **IHSGI:** IHS/Global Insight, Inc., *2009 Energy Outlook* (Lexington, MA, September 2009). **EVA:** Energy Ventures Analysis, Inc., *FUELCAST: Long-Term Outlook* (February 2010).

Table 12. Comparison of electricity projections, 2015 and 2035: *AEO2010*: AEO2010 National Energy Modeling System, run AEO2010R.D111809A. **IHSGI:** IHS/Global Insight, Inc., *2009 Energy Outlook* (Lexington, MA, September 2009). **EVA:** Energy Ventures Analysis, Inc., *FUELCAST: Long-Term Outlook* (February 2010).

Table 13. Comparison of natural gas projections, 2015, 2025, and 2035: *AEO2010*: AEO2010 National Energy Modeling System, run AEO2010R.D111809A. **IHSGI:** IHS/Global Insight, Inc., *U.S. Energy Outlook* (Lexington, MA, September 2008). **EVA:** Energy Ventures Analysis, Inc., *FUELCAST: Long-Term Outlook* (February 2010). **DB:** Deutsche Bank AG, email from Adam Sieminski (November 3, 2009). **SEER:** Strategic Energy and Economic Research, Inc., *Natural Gas Outlook* (November 2009). **Altos**: *Altos World Gas Trade Model* (October 2009); **INFORUM:** INFORUM Base, email from Douglas Meade (Janauray15, 2010).

Table 14. Comparison of liquids projections, 2015, 2025, and 2035: *AEO2010*: AEO2010 National Energy Modeling System, run AEO2010R.D111809A. **IHSGI:** IHS/Global Insight, Inc., *2009 Energy Outlook* (Lexington, MA, September 2009). **EVA:** Energy Ventures Analysis, Inc., *FUELCAST: Long-Term Outlook* (February 2010). **DB:** Deutsche Bank AG, email from Adam Sieminski (November 3, 2009). **P&G:** Purvin and Gertz, Inc., *2009 Global Petroleum Market Outlook*, Vol. 2, Table III-2 (April 2009). **IEA**: International Energy Agency, *World Energy Outlook 2009* (Paris, France, November 2009), Table 1.4.

Table 15. Comparison of coal projections, 2015, 2025, and 2035: *AEO2010*: AEO2010 National Energy Modeling System, run AEO2010R.D111809A. **IHSGI:** IHS/Global Insight, Inc., *2009 Energy Outlook* (Lexington, MA, September 2009). **DB:** Deutsche Bank AG, email from Adam Sieminski (November 3, 2009). **IEA**: International Energy Agency, *World Energy Outlook 2009* (Paris, France, November 2009), Table 1.4. **WM**: Wood Mackenzie Company, *Fall 2009 Long Term Outlook Base Case*. **INFORUM:** INFORUM Base, email from Douglas Meade (January15, 2010).

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. U.S. primary energy consumption, 1980-2035: History: U.S. Energy Information Administration, *Annual Energy Review 2008*, DOE/EIA-0384(2008) (Washington, DC, June 2009). **Projections:** AEO2010 National Energy Modeling System, run AEO2010R. D111809A.

Figure 2. U.S. liquid fuels supply, 1970-2035: History: U.S. Energy Information Administration, *Annual Energy Review 2008*, DOE/EIA-0384(2008) (Washington, DC, June 2009). **Projections:** AEO2010 National Energy Modeling System, run AEO2010R.D111809A.

Figure 3. U.S. natural gas supply, 1990-2035: History: U.S. Energy Information Administration, *Annual Energy Review 2008*, DOE/EIA-0384(2008) (Washington, DC, June 2009). **Projections:** AEO2010 National Energy Modeling System, run AEO2010R.D111809A.

Figure 4. U.S. energy-related carbon dioxide emissions, 2008 and 2035: History: U.S. Energy Information Administration, *Annual Energy Review 2008*, DOE/EIA-0384(2008) (Washington, DC, June 2009). **Projections:** U.S. Energy Information Administration, AEO2010 National Energy Modeling System, run AEO2010R. D111809A.

Figure 5. Projected average fleet-wide fuel economy and CO_2-equivalent emissions compliance levels for passenger cars, model year 2016: Environmental Protection Agency and National Highway Traffic Safety Administration, *Light-Duty Vehicle Greenhouse Gas Emission Standards and Corporate Average Fuel Economy Standards; Final Rule*, 40 CFR, Parts 85, 86, and 600, 49 CFR Parts 531, 533, 537, and 538 [EPA-HQ-OAR-2009-0472; FRL-_8959-4; NHTSA-2009-0059], RIN 2060-AP58; RIN 2127-AK50 (Washington, DC, April 2010), web site www.nhtsa.dot.gov/staticfiles/DOT/NHTSA/Rulemaking/Rules/Associated Files/CAFE-GHG-MY_2012-2016_Final_Rule_v2.pdf.

Figure 6. Projected average fleet-wide fuel economy and CO_2-equivalent emissions compliance levels for light trucks, model year 2016: Environmental Protection Agency and National Highway Traffic Safety Administration, *Light-Duty Vehicle Greenhouse Gas Emission Standards and Corporate Average Fuel Economy Standards; Final Rule*, 40 CFR, Parts 85, 86, and 600, 49 CFR Parts 531, 533, 537, and 538 [EPA-HQ-OAR-2009-0472; FRL-_8959-4; NHTSA-2009-0059], RIN 2060-AP58; RIN 2127-AK50 (Washington, DC, April 2010), web site www.nhtsa.dot.gov/staticfiles/DOT/NHTSA/Rulemaking/Rules/AssociatedFiles/CAFE-GHG-MY_2012-2016_Final_Rule_v2.pdf.

Figure 7. Total energy consumption in three cases, 2005-2035: History: U.S. Energy Information Administration, *Annual Energy Review 2008*, DOE/EIA-0384(2008) (Washington, DC, June 2009). **Projections:** AEO2010 National Energy Modeling System, runs AEO2010R.D111809A, NOSUNSET.D012510A, and EXTENDED.D012410A.

Figure 8. Light-duty vehicle energy consumption in three cases, 2005-2035: History: U.S. Energy Information Administration, *Annual Energy Review 2008*, DOE/EIA-0384(2008) (Washington, DC, June 2009). **Projections:** AEO2010 National Energy Modeling System, runs AEO2010R.D111809A, NOSUNSET.D012510A, and EXTENDED.D012410A.

Figure 9. New light-duty vehicle fuel efficiency standards in two cases, 2005-2035: History: U.S. Energy Information Administration, *Annual Energy Review 2008*, DOE/EIA-0384(2008) (Washington, DC, June 2009). **Projections:** AEO2010 National Energy Modeling System, runs AEO2010R.D111809A and EXTENDED.D012410A.

Figure 10. New light-duty vehicle fuel efficiency standards and fuel efficiency achieved in two cases, 2005-2035: History: U.S. Energy Information Administration, *Annual Energy Review 2008*, DOE/EIA-0384(2008) (Washington, DC, June 2009). **Projections:** AEO-2010 National Energy Modeling System, runs AEO2010R.D111809A, NOSUNSET.D012510A, and EXTENDED.D012410A.

Figure 11. Renewable electricity generation in three cases, 2005-2035: History: U.S. Energy Information Administration, *Annual Energy Review 2008*, DOE/EIA-0384(2008) (Washington, DC, June 2009). **Projections:** AEO-2010 National Energy Modeling System, runs AEO2010R.D111809A, NOSUNSET.D012510A, and EXTENDED.D012410A.

Figure 12. Electricity generation from natural gas in three cases, 2005-2035: History: U.S. Energy Information Administration, *Annual Energy Review 2008*, DOE/EIA-0384(2008) (Washington, DC, June 2009). **Projections:** AEO2010 National Energy Modeling System, runs AEO2010R.D111809A, NOSUNSET.D012510A, and EXTENDED.D012410A.

Figure 13. Energy-related carbon dioxide emissions in three cases, 2005-2035: History: U.S. Energy Information Administration, *Annual Energy Review 2008*, DOE/EIA-0384(2008) (Washington, DC, June 2009). **Projections:** AEO2010 National Energy Modeling System, runs AEO2010R.D111809A, NOSUNSET.D012510A, and EXTENDED.D012410A.

Figure 14. Natural gas wellhead prices in three cases, 2005-2035: History: U.S. Energy Information Administration, *Annual Energy Review 2008*, DOE/EIA-0384 (2008) (Washington, DC, June 2009). **Projections:** AEO2010 National Energy Modeling System, runs AEO2010R.D111809A, NOSUNSET.D012510A, and EXTENDED.D012410A.

Figure 15. Average electricity prices in three cases, 2005-2035: History: U.S. Energy Information Administration, *Annual Energy Review 2008*, DOE/EIA-0384(2008) (Washington, DC, June 2009). **Projections:** AEO2010 National Energy Modeling System, runs AEO2010R.D111809A, NOSUNSET.D012510A, and EXTENDED.D012410A.

Figure 16. Average annual world oil prices in three cases, 1980-2035: History: U.S. Energy Information Administration, *Annual Energy Review 2008*, DOE/EIA-0384 (2008) (Washington, DC, June 2009). **Projections:** AEO2010 National Energy Modeling System, runs AEO2010R.D111809A, LP2010.D011910A, and HP2010.D011910A.

Figure 17. Trends in U.S. oil prices, energy consumption, and economic output, 1950-2035: History: U.S. Energy Information Administration, *Annual Energy Review 2008*, DOE/EIA-0384(2008) (Washington, DC, June 2009). **Projections:** AEO2010 National Energy Modeling System, run AEO2010R.D111809A.

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Figure 91. Average annual delivered coal prices in four cases, 1990-2035: History: **1990-2008:** U.S. Energy Information Administration, *Quarterly Coal Report, October-December 2008*, DOE/EIA-0121(2008/4Q) (Washington, DC, March 2009), and previous issues; *Electric Power Monthly, October 2009*, DOE/EIA-0226(2009/10) (Washington, DC, October 2009); and *Annual Energy Review 2008*, DOE/EIA-0384(2008) (Washington, DC, June 2009). **Projections**: AEO2010 National Energy Modeling System, runs AEO2010R.D111809A, LCCST10.D120909A, HCCST10.D120909A, and HP2010.D011910A.

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Figure 95. Nitrogen oxide emissions from electricity generation, 2000-2035: 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. **2008 and Projections:** AEO2010 National Energy Modeling System, run AEO2010R.D111809A.

Appendixes

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

Supply, Disposition, and Prices	Reference Case							Annual Growth 2008-2035 (percent)
	2007	2008	2015	2020	2025	2030	2035	
Production								
Crude Oil and Lease Condensate	10.75	10.51	12.41	13.19	13.22	13.34	13.50	0.9%
Natural Gas Plant Liquids	2.41	2.57	2.27	2.31	2.24	2.32	2.37	-0.3%
Dry Natural Gas	19.62	21.14	19.83	20.54	21.90	23.00	23.92	0.5%
Coal[1]	23.49	23.86	23.31	23.71	24.36	24.68	25.19	0.2%
Nuclear Power	8.46	8.46	8.75	9.26	9.29	9.29	9.41	0.4%
Hydropower	2.45	2.46	2.96	2.96	2.98	2.98	2.99	0.7%
Biomass[2]	3.15	3.97	4.60	5.63	6.90	7.93	9.27	3.2%
Other Renewable Energy[3]	0.99	1.17	3.01	3.01	3.07	3.17	3.36	4.0%
Other[4]	0.81	0.10	0.73	0.89	0.94	0.92	0.81	7.9%
Total	**72.14**	**74.23**	**77.88**	**81.51**	**84.91**	**87.63**	**90.83**	**0.8%**
Imports								
Crude Oil	21.91	21.39	19.66	18.95	19.21	19.38	19.34	-0.4%
Liquid Fuels and Other Petroleum[5]	6.98	6.38	5.54	5.61	5.76	5.86	6.08	-0.2%
Natural Gas	4.72	4.06	3.59	4.10	3.94	3.79	3.49	-0.6%
Other Imports[6]	0.99	0.96	0.79	0.96	0.88	0.95	1.32	1.2%
Total	**34.60**	**32.79**	**29.58**	**29.62**	**29.80**	**29.97**	**30.23**	**-0.3%**
Exports								
Petroleum[7]	2.83	3.71	3.53	3.74	3.91	4.02	4.12	0.4%
Natural Gas	0.83	1.01	1.14	1.44	1.69	1.87	1.96	2.5%
Coal	1.51	2.07	1.49	1.33	1.20	0.87	0.79	-3.5%
Total	**5.17**	**6.80**	**6.16**	**6.50**	**6.80**	**6.76**	**6.87**	**0.0%**
Discrepancy[8]	**-0.07**	**0.13**	**-0.30**	**-0.38**	**-0.35**	**-0.33**	**-0.32**	**- -**
Consumption								
Liquid Fuels and Other Petroleum[9]	40.59	38.35	38.81	39.36	40.14	41.08	42.02	0.3%
Natural Gas	23.67	23.91	22.35	23.27	24.24	25.01	25.56	0.2%
Coal[10]	22.71	22.41	22.35	23.01	23.63	24.25	25.11	0.4%
Nuclear Power	8.46	8.46	8.75	9.26	9.29	9.29	9.41	0.4%
Hydropower	2.45	2.46	2.96	2.96	2.98	2.98	2.99	0.7%
Biomass[11]	2.54	3.10	3.17	3.93	4.70	5.19	5.83	2.4%
Other Renewable Energy[3]	0.99	1.17	3.01	3.01	3.07	3.17	3.36	4.0%
Other[12]	0.23	0.24	0.20	0.20	0.21	0.20	0.22	-0.3%
Total	**101.65**	**100.09**	**101.61**	**105.00**	**108.26**	**111.18**	**114.51**	**0.5%**
Prices (2008 dollars per unit)								
Petroleum (dollars per barrel)								
Imported Low Sulfur Light Crude Oil Price[13]	73.93	99.57	94.52	108.28	115.09	123.50	133.22	1.1%
Imported Crude Oil Price[13]	68.69	92.61	86.88	98.14	104.49	111.49	121.37	1.0%
Natural Gas (dollars per million Btu)								
Price at Henry Hub	7.12	8.86	6.27	6.64	6.99	8.05	8.88	0.0%
Wellhead Price[14]	6.38	7.85	5.54	5.87	6.18	7.11	7.84	-0.0%
Natural Gas (dollars per thousand cubic feet)								
Wellhead Price[14]	6.56	8.07	5.70	6.03	6.35	7.31	8.06	-0.0%
Coal (dollars per ton)								
Minemouth Price[15]	26.40	31.26	30.38	30.01	28.19	27.43	28.10	-0.4%
Coal (dollars per million Btu)								
Minemouth Price[15]	1.30	1.55	1.52	1.51	1.44	1.41	1.44	-0.3%
Average Delivered Price[16]	1.89	2.16	2.11	2.08	2.07	2.09	2.13	-0.0%
Average Electricity Price (cents per kilowatthour)	9.3	9.8	8.9	9.0	9.3	9.7	10.2	0.1%

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

Supply, Disposition, and Prices	Reference Case							Annual Growth 2008-2035 (percent)
	2007	2008	2015	2020	2025	2030	2035	
Prices (nominal dollars per unit)								
Petroleum (dollars per barrel)								
Imported Low Sulfur Light Crude Oil Price[13]	72.32	99.57	105.33	132.33	156.20	186.40	223.88	3.0%
Imported Crude Oil Price[13]	67.19	92.61	96.82	119.94	141.80	168.28	203.97	3.0%
Natural Gas (dollars per million Btu)								
Price at Henry Hub	6.96	8.86	6.99	8.11	9.49	12.15	14.92	1.9%
Wellhead Price[14]	6.24	7.85	6.17	7.17	8.38	10.73	13.18	1.9%
Natural Gas (dollars per thousand cubic feet)								
Wellhead Price[14]	6.42	8.07	6.35	7.37	8.62	11.03	13.55	1.9%
Coal (dollars per ton)								
Minemouth Price[15]	25.82	31.26	33.86	36.67	38.25	41.40	47.23	1.5%
Coal (dollars per million Btu)								
Minemouth Price[15]	1.27	1.55	1.69	1.84	1.95	2.13	2.43	1.7%
Average Delivered Price[16]	1.85	2.16	2.35	2.55	2.81	3.16	3.58	1.9%
Average Electricity Price (cents per kilowatthour)	9.1	9.8	9.9	11.1	12.6	14.7	17.1	2.1%

[1]Includes waste coal.
[2]Includes grid-connected electricity from wood and wood 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 and crude oil consumed as a fuel. Refer to Table A17 for detailed renewable liquid fuels consumption.
[10]Excludes coal converted to coal-based synthetic liquids and coal-based synthetic natural gas.
[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 2007 and 2008 are model results and may differ slightly from official EIA data reports.
Sources: 2007 natural gas supply values: Energy Information Administration (EIA), *Natural Gas Annual 2007*, DOE/EIA-0131(2007) (Washington, DC, January 2009). 2008 natural gas supply values and natural gas wellhead price: EIA, *Natural Gas Monthly*, DOE/EIA-0130(2009/07) (Washington, DC, July 2009). 2007 natural gas wellhead price: Minerals Management Service and EIA, *Natural Gas Annual 2007*, DOE/EIA-0131(2007) (Washington, DC, January 2009). 2007 and 2008 coal minemouth and delivered coal prices: EIA, *Annual Coal Report 2008*, DOE/EIA-0584(2008) (Washington, DC, September 2009). 2008 petroleum supply values and 2007 crude oil and lease condensate production: EIA, *Petroleum Supply Annual 2008,* DOE/EIA-0340(2008)/1 (Washington, DC, June 2009). Other 2007 petroleum supply values: EIA, *Petroleum Supply Annual 2007,* DOE/EIA-0340(2007)/1 (Washington, DC, July 2008). 2007 and 2008 low sulfur light crude oil price: EIA, Form EIA-856, "Monthly Foreign Crude Oil Acquisition Report." Other 2007 and 2008 coal values: *Quarterly Coal Report, October-December 2008*, DOE/EIA-0121(2008/4Q) (Washington, DC, March 2009). Other 2007 and 2008 values: EIA, *Annual Energy Review 2008*, DOE/EIA-0384(2008) (Washington, DC, June 2009). **Projections:** EIA, AEO2010 National Energy Modeling System run AEO2010R.D111809A.

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

Sector and Source	Reference Case							Annual Growth 2008-2035 (percent)
	2007	2008	2015	2020	2025	2030	2035	
Energy Consumption								
Residential								
Liquefied Petroleum Gases	0.48	0.45	0.41	0.40	0.40	0.40	0.40	-0.4%
Kerosene	0.04	0.04	0.04	0.04	0.03	0.03	0.03	-1.0%
Distillate Fuel Oil	0.73	0.68	0.59	0.53	0.49	0.45	0.41	-1.9%
Liquid Fuels and Other Petroleum Subtotal	1.25	1.18	1.04	0.97	0.92	0.88	0.85	-1.2%
Natural Gas	4.84	5.01	4.85	4.97	5.04	5.03	5.01	0.0%
Coal	0.01	0.01	0.01	0.01	0.01	0.01	0.01	-1.3%
Renewable Energy[1]	0.41	0.45	0.40	0.42	0.42	0.42	0.43	-0.1%
Electricity	4.75	4.71	4.78	5.02	5.30	5.58	5.83	0.8%
Delivered Energy	**11.25**	**11.34**	**11.07**	**11.38**	**11.69**	**11.93**	**12.12**	**0.2%**
Electricity Related Losses	10.29	10.20	10.24	10.65	11.08	11.45	11.79	0.5%
Total	**21.54**	**21.54**	**21.31**	**22.03**	**22.76**	**23.38**	**23.92**	**0.4%**
Commercial								
Liquefied Petroleum Gases	0.08	0.08	0.09	0.09	0.09	0.09	0.09	0.5%
Motor Gasoline[2]	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.2%
Kerosene	0.01	0.01	0.01	0.01	0.01	0.01	0.01	1.7%
Distillate Fuel Oil	0.38	0.36	0.31	0.29	0.28	0.27	0.26	-1.2%
Residual Fuel Oil	0.08	0.07	0.09	0.09	0.09	0.09	0.09	0.7%
Liquid Fuels and Other Petroleum Subtotal	0.62	0.58	0.55	0.53	0.53	0.52	0.52	-0.4%
Natural Gas	3.10	3.21	3.32	3.43	3.55	3.66	3.79	0.6%
Coal	0.06	0.07	0.07	0.07	0.07	0.07	0.07	0.0%
Renewable Energy[3]	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.0%
Electricity	4.56	4.61	5.00	5.37	5.76	6.16	6.55	1.3%
Delivered Energy	**8.44**	**8.58**	**9.04**	**9.50**	**10.00**	**10.51**	**11.04**	**0.9%**
Electricity Related Losses	9.88	10.00	10.72	11.39	12.03	12.63	13.27	1.1%
Total	**18.32**	**18.58**	**19.77**	**20.89**	**22.03**	**23.14**	**24.30**	**1.0%**
Industrial[4]								
Liquefied Petroleum Gases	2.28	2.14	2.31	2.61	2.55	2.46	2.35	0.3%
Motor Gasoline[2]	0.31	0.30	0.30	0.30	0.30	0.30	0.30	0.1%
Distillate Fuel Oil	1.26	1.19	1.19	1.19	1.17	1.17	1.17	-0.1%
Residual Fuel Oil	0.19	0.18	0.14	0.14	0.14	0.14	0.13	-1.1%
Petrochemical Feedstocks	1.31	1.12	1.09	0.81	0.82	0.82	0.81	-1.2%
Other Petroleum[5]	4.45	4.05	4.01	3.95	3.89	3.94	3.92	-0.1%
Liquid Fuels and Other Petroleum Subtotal	9.80	8.99	9.04	9.01	8.87	8.82	8.70	-0.1%
Natural Gas	6.81	6.84	7.08	7.23	7.14	6.94	6.91	0.0%
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]	1.22	1.32	1.11	1.12	1.23	1.26	1.29	-0.1%
Natural Gas Subtotal	8.03	8.16	8.19	8.35	8.37	8.20	8.20	0.0%
Metallurgical Coal	0.60	0.58	0.52	0.54	0.50	0.44	0.36	-1.7%
Other Industrial Coal	1.21	1.17	1.07	1.08	1.07	1.06	1.04	-0.4%
Coal-to-Liquids Heat and Power	0.00	0.00	0.16	0.24	0.34	0.45	0.55	27.6%
Net Coal Coke Imports	0.03	0.04	0.01	0.01	0.01	0.01	-0.00	- -
Coal Subtotal	1.83	1.79	1.76	1.88	1.92	1.96	1.95	0.3%
Biofuels Heat and Coproducts[7]	0.40	1.03	0.77	1.02	1.49	1.90	2.56	3.4%
Renewable Energy[8]	1.62	1.50	1.59	1.69	1.74	1.79	1.83	0.7%
Electricity	3.51	3.35	3.40	3.51	3.49	3.47	3.47	0.1%
Delivered Energy	**25.19**	**24.81**	**24.76**	**25.45**	**25.88**	**26.14**	**26.70**	**0.3%**
Electricity Related Losses	7.60	7.26	7.29	7.45	7.29	7.12	7.01	-0.1%
Total	**32.79**	**32.07**	**32.05**	**32.90**	**33.18**	**33.26**	**33.72**	**0.2%**

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

Sector and Source	Reference Case							Annual Growth 2008-2035 (percent)
	2007	2008	2015	2020	2025	2030	2035	
Transportation								
Liquefied Petroleum Gases	0.03	0.02	0.02	0.02	0.02	0.02	0.03	0.7%
E85[9]	0.00	0.01	0.01	0.26	0.52	0.82	1.75	23.3%
Motor Gasoline[2]	17.32	16.76	17.02	16.77	16.91	16.97	16.44	-0.1%
Jet Fuel[10]	3.27	3.15	3.26	3.48	3.62	3.72	3.80	0.7%
Distillate Fuel Oil[11]	6.46	6.09	6.32	6.72	7.13	7.69	8.28	1.1%
Residual Fuel Oil	0.99	0.93	0.94	0.95	0.96	0.97	0.97	0.2%
Other Petroleum[12]	0.18	0.17	0.17	0.18	0.18	0.18	0.19	0.3%
Liquid Fuels and Other Petroleum Subtotal	28.26	27.14	27.73	28.38	29.34	30.37	31.47	0.5%
Pipeline Fuel Natural Gas	0.64	0.64	0.61	0.63	0.72	0.74	0.74	0.5%
Compressed Natural Gas	0.04	0.04	0.05	0.08	0.11	0.15	0.19	5.8%
Liquid Hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	- -
Electricity	0.02	0.02	0.03	0.03	0.04	0.05	0.06	3.5%
Delivered Energy	**28.96**	**27.85**	**28.42**	**29.12**	**30.21**	**31.30**	**32.46**	**0.6%**
Electricity Related Losses	0.05	0.05	0.05	0.06	0.08	0.09	0.11	3.2%
Total	**29.01**	**27.90**	**28.48**	**29.18**	**30.29**	**31.40**	**32.58**	**0.6%**
Delivered Energy Consumption for All Sectors								
Liquefied Petroleum Gases	2.88	2.70	2.82	3.12	3.06	2.98	2.87	0.2%
E85[9]	0.00	0.01	0.01	0.26	0.52	0.82	1.75	23.3%
Motor Gasoline[2]	17.69	17.12	17.38	17.14	17.28	17.33	16.80	-0.1%
Jet Fuel[10]	3.27	3.15	3.26	3.48	3.62	3.72	3.80	0.7%
Kerosene	0.07	0.06	0.06	0.06	0.06	0.06	0.06	-0.3%
Distillate Fuel Oil	8.83	8.33	8.40	8.73	9.07	9.57	10.13	0.7%
Residual Fuel Oil	1.26	1.19	1.17	1.17	1.18	1.19	1.19	0.0%
Petrochemical Feedstocks	1.31	1.12	1.09	0.81	0.82	0.82	0.81	-1.2%
Other Petroleum[13]	4.62	4.21	4.17	4.12	4.06	4.11	4.10	-0.1%
Liquid Fuels and Other Petroleum Subtotal	39.93	37.89	38.35	38.89	39.66	40.59	41.53	0.3%
Natural Gas	14.79	15.10	15.31	15.71	15.84	15.78	15.91	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]	1.22	1.32	1.11	1.12	1.23	1.26	1.29	-0.1%
Pipeline Natural Gas	0.64	0.64	0.61	0.63	0.72	0.74	0.74	0.5%
Natural Gas Subtotal	16.65	17.07	17.03	17.46	17.79	17.78	17.94	0.2%
Metallurgical Coal	0.60	0.58	0.52	0.54	0.50	0.44	0.36	-1.7%
Other Coal	1.28	1.24	1.15	1.16	1.15	1.13	1.11	-0.4%
Coal-to-Liquids Heat and Power	0.00	0.00	0.16	0.24	0.34	0.45	0.55	27.6%
Net Coal Coke Imports	0.03	0.04	0.01	0.01	0.01	0.01	-0.00	- -
Coal Subtotal	1.91	1.86	1.84	1.95	2.00	2.03	2.02	0.3%
Biofuels Heat and Coproducts[7]	0.40	1.03	0.77	1.02	1.49	1.90	2.56	3.4%
Renewable Energy[14]	2.13	2.05	2.10	2.21	2.27	2.32	2.37	0.5%
Liquid Hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	- -
Electricity	12.84	12.69	13.20	13.93	14.58	15.26	15.90	0.8%
Delivered Energy	**73.84**	**72.59**	**73.30**	**75.45**	**77.78**	**79.88**	**82.33**	**0.5%**
Electricity Related Losses	27.81	27.50	28.31	29.55	30.48	31.29	32.19	0.6%
Total	**101.65**	**100.09**	**101.61**	**105.00**	**108.26**	**111.18**	**114.51**	**0.5%**
Electric Power[15]								
Distillate Fuel Oil	0.11	0.10	0.12	0.13	0.13	0.14	0.14	1.1%
Residual Fuel Oil	0.55	0.36	0.33	0.34	0.34	0.35	0.35	-0.1%
Liquid Fuels and Other Petroleum Subtotal	0.66	0.47	0.46	0.47	0.48	0.49	0.49	0.2%
Natural Gas	7.03	6.84	5.32	5.81	6.45	7.23	7.62	0.4%
Steam Coal	20.81	20.55	20.51	21.06	21.63	22.22	23.09	0.4%
Nuclear Power	8.46	8.46	8.75	9.26	9.29	9.29	9.41	0.4%
Renewable Energy[16]	3.45	3.65	6.27	6.69	7.00	7.13	7.26	2.6%
Electricity Imports	0.11	0.11	0.07	0.07	0.08	0.07	0.09	-0.9%
Total[17]	**40.65**	**40.20**	**41.51**	**43.48**	**45.06**	**46.55**	**48.09**	**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 2008-2035 (percent)
	2007	2008	2015	2020	2025	2030	2035	
Total Energy Consumption								
Liquefied Petroleum Gases	2.88	2.70	2.82	3.12	3.06	2.98	2.87	0.2%
E85[9]	0.00	0.01	0.01	0.26	0.52	0.82	1.75	23.3%
Motor Gasoline[2]	17.69	17.12	17.38	17.14	17.28	17.33	16.80	-0.1%
Jet Fuel[10]	3.27	3.15	3.26	3.48	3.62	3.72	3.80	0.7%
Kerosene	0.07	0.06	0.06	0.06	0.06	0.06	0.06	-0.3%
Distillate Fuel Oil	8.94	8.43	8.53	8.86	9.20	9.71	10.27	0.7%
Residual Fuel Oil	1.81	1.55	1.50	1.51	1.52	1.54	1.55	-0.0%
Petrochemical Feedstocks	1.31	1.12	1.09	0.81	0.82	0.82	0.81	-1.2%
Other Petroleum[13]	4.62	4.21	4.17	4.12	4.06	4.11	4.10	-0.1%
Liquid Fuels and Other Petroleum Subtotal	40.59	38.35	38.81	39.36	40.14	41.08	42.02	0.3%
Natural Gas	21.82	21.94	20.63	21.51	22.29	23.01	23.53	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]	1.22	1.32	1.11	1.12	1.23	1.26	1.29	-0.1%
Pipeline Natural Gas	0.64	0.64	0.61	0.63	0.72	0.74	0.74	0.5%
Natural Gas Subtotal	23.67	23.91	22.35	23.27	24.24	25.01	25.56	0.2%
Metallurgical Coal	0.60	0.58	0.52	0.54	0.50	0.44	0.36	-1.7%
Other Coal	22.09	21.79	21.66	22.22	22.78	23.36	24.20	0.4%
Coal-to-Liquids Heat and Power	0.00	0.00	0.16	0.24	0.34	0.45	0.55	27.6%
Net Coal Coke Imports	0.03	0.04	0.01	0.01	0.01	0.01	-0.00	- -
Coal Subtotal	22.71	22.41	22.35	23.01	23.63	24.25	25.11	0.4%
Nuclear Power	8.46	8.46	8.75	9.26	9.29	9.29	9.41	0.4%
Biofuels Heat and Coproducts[7]	0.40	1.03	0.77	1.02	1.49	1.90	2.56	3.4%
Renewable Energy[18]	5.58	5.70	8.37	8.90	9.27	9.44	9.63	2.0%
Liquid Hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	- -
Electricity Imports	0.11	0.11	0.07	0.07	0.08	0.07	0.09	-0.9%
Total	**101.65**	**100.09**	**101.61**	**105.00**	**108.26**	**111.18**	**114.51**	**0.5%**
Energy Use and Related Statistics								
Delivered Energy Use	73.84	72.59	73.30	75.45	77.78	79.88	82.33	0.5%
Total Energy Use	101.65	100.09	101.61	105.00	108.26	111.18	114.51	0.5%
Ethanol Consumed in Motor Gasoline and E85	0.56	0.82	1.23	1.38	1.56	1.76	2.35	4.0%
Population (millions)	302.41	305.37	326.70	342.55	358.62	374.67	390.70	0.9%
Gross Domestic Product (billion 2000 dollars)	11524	11652	13289	15416	17561	19883	22362	2.4%
Carbon Dioxide Emissions (million metric tons)	5986.4	5814.4	5730.7	5851.5	6015.8	6175.9	6320.4	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 electricity generation from wind and solar photovoltaic sources.
[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 electricity generation from wind and solar photovoltaic sources.
[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]The energy content of biofuels feedstock minus the energy content of liquid fuel produced.
[8]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.
[9]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.
[10]Includes only kerosene type.
[11]Diesel fuel for on- and off- road use.
[12]Includes aviation gasoline and lubricants.
[13]Includes unfinished oils, natural gasoline, motor gasoline blending components, aviation gasoline, lubricants, still gas, asphalt, road oil, petroleum coke, and miscellaneous petroleum products.
[14]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.
[15]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.
[16]Includes conventional hydroelectric, geothermal, wood and wood waste, biogenic municipal waste, other biomass, wind, photovoltaic, and solar thermal sources. Excludes net electricity imports.
[17]Includes non-biogenic municipal waste not included above.
[18]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 2007 and 2008 are model results and may differ slightly from official EIA data reports.
Sources: 2007 and 2008 consumption based on: Energy Information Administration (EIA), *Annual Energy Review 2008*, DOE/EIA-0384(2008) (Washington, DC, June 2009). 2007 and 2008 population and gross domestic product: IHS Global Insight Industry and Employment models, August 2009. 2007 and 2008 carbon dioxide emissions: EIA, *Emissions of Greenhouse Gases in the United States 2008,* DOE/EIA-0573(2008) (Washington, DC, December 2009). **Projections:** EIA, AEO2010 National Energy Modeling System run AEO2010R.D111809A.

Table A3. Energy Prices by Sector and Source
(2008 Dollars per Million Btu, Unless Otherwise Noted)

Sector and Source	Reference Case							Annual Growth 2008-2035 (percent)
	2007	2008	2015	2020	2025	2030	2035	
Residential								
Liquefied Petroleum Gases	26.25	29.35	28.03	30.29	31.55	32.81	34.65	0.6%
Distillate Fuel Oil	20.30	24.47	21.08	24.10	25.23	26.61	28.66	0.6%
Natural Gas	12.94	13.48	11.56	11.95	12.29	13.44	14.40	0.2%
Electricity	31.82	33.29	31.43	31.84	32.26	33.46	34.71	0.2%
Commercial								
Liquefied Petroleum Gases	20.65	26.15	24.77	27.02	28.26	29.50	31.32	0.7%
Distillate Fuel Oil	17.48	21.50	18.72	21.60	22.72	24.11	26.13	0.7%
Residual Fuel Oil	8.39	15.52	13.13	15.46	16.54	17.54	18.84	0.7%
Natural Gas	11.20	11.94	9.99	10.35	10.70	11.78	12.66	0.2%
Electricity	28.81	30.47	26.55	27.12	27.72	28.99	30.37	-0.0%
Industrial[1]								
Liquefied Petroleum Gases	22.01	24.20	22.49	24.86	26.12	27.38	29.25	0.7%
Distillate Fuel Oil	18.07	22.31	19.00	21.83	22.97	24.40	26.48	0.6%
Residual Fuel Oil	8.84	16.31	16.47	18.20	19.23	20.27	21.72	1.1%
Natural Gas[2]	7.58	9.11	6.45	6.70	7.02	7.98	8.73	-0.2%
Metallurgical Coal	3.69	4.49	5.08	5.32	5.24	5.11	5.06	0.4%
Other Industrial Coal	2.48	2.84	2.69	2.66	2.63	2.66	2.71	-0.2%
Coal to Liquids	- -	- -	1.42	1.46	1.49	1.44	1.51	- -
Electricity	19.02	20.21	17.37	17.92	18.50	19.58	20.71	0.1%
Transportation								
Liquefied Petroleum Gases[3]	23.83	29.93	27.88	30.13	31.36	32.58	34.38	0.5%
E85[4]	27.43	26.93	25.55	26.95	28.86	30.64	32.23	0.7%
Motor Gasoline[5]	23.66	26.76	25.37	27.59	28.87	30.42	32.33	0.7%
Jet Fuel[6]	15.77	22.71	19.04	21.69	22.92	24.51	26.48	0.6%
Diesel Fuel (distillate fuel oil)[7]	21.55	27.65	22.93	25.60	26.63	27.96	29.96	0.3%
Residual Fuel Oil	9.19	14.49	13.58	14.99	15.93	17.10	18.60	0.9%
Natural Gas[8]	13.84	15.96	13.37	13.44	13.43	14.19	14.78	-0.3%
Electricity	32.03	33.73	28.79	28.55	28.63	31.01	33.26	-0.1%
Electric Power[9]								
Distillate Fuel Oil	15.75	19.37	17.36	20.25	21.35	22.71	24.70	0.9%
Residual Fuel Oil	9.04	14.56	15.53	17.22	18.30	19.55	21.12	1.4%
Natural Gas	7.26	9.09	6.08	6.42	6.75	7.73	8.46	-0.3%
Steam Coal	1.80	2.05	2.01	1.98	1.99	2.03	2.09	0.1%
Average Price to All Users[10]								
Liquefied Petroleum Gases	18.94	20.19	20.30	22.15	23.34	24.55	26.37	1.0%
E85[4]	27.43	26.93	25.55	26.95	28.86	30.64	32.23	0.7%
Motor Gasoline[5]	23.55	26.54	25.36	27.59	28.87	30.41	32.32	0.7%
Jet Fuel	15.77	22.71	19.04	21.69	22.92	24.51	26.48	0.6%
Distillate Fuel Oil	20.71	26.27	22.03	24.79	25.89	27.29	29.34	0.4%
Residual Fuel Oil	9.07	14.77	14.26	15.81	16.80	17.96	19.46	1.0%
Natural Gas	9.19	10.53	8.14	8.44	8.75	9.74	10.54	0.0%
Metallurgical Coal	3.69	4.49	5.08	5.32	5.24	5.11	5.06	0.4%
Other Coal	1.84	2.10	2.05	2.02	2.02	2.06	2.12	0.0%
Coal to Liquids	- -	- -	1.42	1.46	1.49	1.44	1.51	- -
Electricity	27.25	28.81	25.95	26.51	27.17	28.49	29.87	0.1%
Non-Renewable Energy Expenditures by Sector (billion 2008 dollars)								
Residential	241.67	254.66	230.89	245.14	258.70	280.40	301.11	0.6%
Commercial	176.61	191.19	176.90	193.15	210.07	234.79	261.07	1.2%
Industrial	219.69	244.81	213.14	234.86	241.75	253.51	267.18	0.3%
Transportation	613.37	705.86	655.77	729.77	782.71	846.64	908.01	0.9%
Total Non-Renewable Expenditures	1251.35	1396.52	1276.69	1402.91	1493.23	1615.34	1737.37	0.8%
Transportation Renewable Expenditures	0.05	0.17	0.21	7.12	15.06	25.05	56.42	24.1%
Total Expenditures	**1251.39**	**1396.69**	**1276.90**	**1410.03**	**1508.29**	**1640.39**	**1793.79**	**0.9%**

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

Sector and Source	Reference Case							Annual Growth 2008-2035 (percent)
	2007	2008	2015	2020	2025	2030	2035	
Residential								
Liquefied Petroleum Gases	25.67	29.35	31.23	37.02	42.82	49.52	58.23	2.6%
Distillate Fuel Oil	19.86	24.47	23.49	29.45	34.24	40.16	48.16	2.5%
Natural Gas	12.66	13.48	12.88	14.61	16.68	20.29	24.20	2.2%
Electricity	31.12	33.29	35.02	38.92	43.78	50.50	58.33	2.1%
Commercial								
Liquefied Petroleum Gases	20.20	26.15	27.61	33.02	38.35	44.53	52.64	2.6%
Distillate Fuel Oil	17.10	21.50	20.86	26.39	30.83	36.38	43.92	2.7%
Residual Fuel Oil	8.21	15.52	14.63	18.90	22.45	26.47	31.66	2.7%
Natural Gas	10.96	11.94	11.14	12.65	14.53	17.78	21.27	2.2%
Electricity	28.18	30.47	29.58	33.15	37.62	43.75	51.04	1.9%
Industrial[1]								
Liquefied Petroleum Gases	21.53	24.20	25.06	30.38	35.45	41.33	49.15	2.7%
Distillate Fuel Oil	17.68	22.31	21.18	26.68	31.18	36.83	44.51	2.6%
Residual Fuel Oil	8.65	16.31	18.35	22.24	26.10	30.60	36.50	3.0%
Natural Gas[2]	7.41	9.11	7.18	8.19	9.52	12.04	14.67	1.8%
Metallurgical Coal	3.61	4.49	5.66	6.50	7.11	7.72	8.50	2.4%
Other Industrial Coal	2.43	2.84	3.00	3.26	3.56	4.01	4.55	1.8%
Coal to Liquids	- -	- -	1.58	1.79	2.02	2.18	2.53	- -
Electricity	18.60	20.21	19.36	21.90	25.11	29.55	34.80	2.0%
Transportation								
Liquefied Petroleum Gases[3]	23.31	29.93	31.07	36.82	42.56	49.17	57.77	2.5%
E85[4]	26.83	26.93	28.47	32.94	39.17	46.25	54.17	2.6%
Motor Gasoline[5]	23.15	26.76	28.27	33.72	39.18	45.91	54.33	2.7%
Jet Fuel[6]	15.42	22.71	21.21	26.51	31.10	36.99	44.51	2.5%
Diesel Fuel (distillate fuel oil)[7]	21.08	27.65	25.56	31.28	36.13	42.20	50.35	2.2%
Residual Fuel Oil	8.99	14.49	15.13	18.32	21.63	25.81	31.26	2.9%
Natural Gas[8]	13.54	15.96	14.90	16.43	18.23	21.42	24.84	1.7%
Electricity	31.32	33.73	32.08	34.89	38.86	46.80	55.89	1.9%
Electric Power[9]								
Distillate Fuel Oil	15.41	19.37	19.35	24.75	28.98	34.28	41.52	2.9%
Residual Fuel Oil	8.84	14.56	17.30	21.05	24.83	29.50	35.49	3.4%
Natural Gas	7.10	9.09	6.77	7.85	9.17	11.66	14.22	1.7%
Steam Coal	1.76	2.05	2.24	2.42	2.69	3.06	3.51	2.0%

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

Sector and Source	Reference Case							Annual Growth 2008-2035 (percent)
	2007	2008	2015	2020	2025	2030	2035	
Average Price to All Users[10]								
Liquefied Petroleum Gases	18.53	20.19	22.62	27.06	31.68	37.05	44.32	3.0%
E85[4]	26.83	26.93	28.47	32.94	39.17	46.25	54.17	2.6%
Motor Gasoline[5]	23.03	26.54	28.27	33.71	39.17	45.90	54.32	2.7%
Jet Fuel	15.42	22.71	21.21	26.51	31.10	36.99	44.51	2.5%
Distillate Fuel Oil	20.26	26.27	24.55	30.30	35.14	41.20	49.31	2.4%
Residual Fuel Oil	8.87	14.77	15.89	19.33	22.80	27.11	32.70	3.0%
Natural Gas	8.99	10.53	9.07	10.32	11.88	14.70	17.71	1.9%
Metallurgical Coal	3.61	4.49	5.66	6.50	7.11	7.72	8.50	2.4%
Other Coal	1.80	2.10	2.28	2.47	2.74	3.11	3.56	2.0%
Coal to Liquids	- -	- -	1.58	1.79	2.02	2.18	2.53	- -
Electricity	26.66	28.81	28.92	32.40	36.87	43.00	50.19	2.1%
Non-Renewable Energy Expenditures by Sector (billion nominal dollars)								
Residential	236.38	254.66	257.29	299.59	351.09	423.22	506.03	2.6%
Commercial	172.75	191.19	197.13	236.05	285.09	354.37	438.74	3.1%
Industrial	214.89	244.81	237.51	287.03	328.09	382.62	449.00	2.3%
Transportation	599.94	705.86	730.78	891.87	1062.24	1277.85	1525.95	2.9%
Total Non-Renewable Expenditures	1223.96	1396.52	1422.72	1714.54	2026.51	2438.06	2919.72	2.8%
Transportation Renewable Expenditures	0.04	0.17	0.24	8.70	20.44	37.81	94.81	26.5%
Total Expenditures	**1224.00**	**1396.69**	**1422.95**	**1723.24**	**2046.94**	**2475.87**	**3014.53**	**2.9%**

[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 and 2008 are model results and may differ slightly from official EIA data reports.
Sources: 2007 and 2008 prices for motor gasoline, distillate fuel oil, and jet fuel are based on prices in the Energy Information Administration (EIA), *Petroleum Marketing Annual 2008*, DOE/EIA-0487(2008) (Washington, DC, August 2009). 2007 residential and commercial natural gas delivered prices: EIA,*Natural Gas Annual 2007*, DOE/EIA-0131(2007) (Washington, DC, January 2009). 2008 residential and commercial natural gas delivered prices: EIA, *Natural Gas Monthly*, DOE/EIA-0130(2009/07) (Washington, DC, July 2009). 2007 and 2008 industrial natural gas delivered prices are estimated based on: EIA, *Manufacturing Energy Consumption Survey* and industrial and wellhead prices from the *Natural Gas Annual 2007*, DOE/EIA-0131(2007) (Washington, DC, January 2009) and the *Natural Gas Monthly*, DOE/EIA-0130(2009/07) (Washington, DC, July 2009). 2007 transportation sector natural gas delivered prices are based on: EIA, *Natural Gas Annual 2007*, DOE/EIA-0131(2007) (Washington, DC, January 2009) and estimated State taxes, Federal taxes, and dispensing costs or charges. 2008 transportation sector natural gas delivered prices are model results. 2007 and 2008 electric power sector natural gas prices: EIA, *Electric Power Monthly*, DOE/EIA-0226, April 2008 and April 2009, Table 4.13.B. 2007 and 2008 coal prices based on: EIA, *Quarterly Coal Report, October-December 2008*, DOE/EIA-0121(2008/4Q) (Washington, DC, March 2009) and EIA, AEO2010 National Energy Modeling System run AEO2010R.D111809A. 2007 and 2008 electricity prices: EIA, *Annual Energy Review 2008*, DOE/EIA-0384(2008) (Washington, DC, June 2009). 2007 and 2008 E85 prices derived from monthly prices in the Clean Cities Alternative Fuel Price Report. **Projections:** EIA, AEO2010 National Energy Modeling System run AEO2010R.D111809A.

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

Key Indicators and Consumption	Reference Case							Annual Growth 2008-2035 (percent)
	2007	2008	2015	2020	2025	2030	2035	
Key Indicators								
Households (millions)								
Single-Family	80.79	81.32	87.69	92.78	97.25	101.30	104.85	0.9%
Multifamily	24.91	25.27	27.01	28.86	30.82	32.73	34.59	1.2%
Mobile Homes	6.77	6.74	6.63	6.94	7.17	7.31	7.36	0.3%
Total	**112.48**	**113.33**	**121.33**	**128.58**	**135.25**	**141.34**	**146.79**	**1.0%**
Average House Square Footage	**1646**	**1658**	**1763**	**1831**	**1888**	**1938**	**1982**	**0.7%**
Energy Intensity								
(million Btu per household)								
Delivered Energy Consumption	100.1	100.1	91.2	88.5	86.4	84.4	82.6	-0.7%
Total Energy Consumption	191.5	190.1	175.7	171.3	168.3	165.4	162.9	-0.6%
(thousand Btu per square foot)								
Delivered Energy Consumption	60.8	60.4	51.8	48.4	45.8	43.5	41.7	-1.4%
Total Energy Consumption	116.4	114.6	99.6	93.6	89.1	85.3	82.2	-1.2%
Delivered Energy Consumption by Fuel								
Electricity								
Space Heating	0.27	0.28	0.28	0.28	0.28	0.28	0.28	-0.1%
Space Cooling	0.91	0.77	0.83	0.87	0.92	0.96	0.99	0.9%
Water Heating	0.43	0.43	0.48	0.51	0.53	0.53	0.53	0.7%
Refrigeration	0.38	0.38	0.36	0.37	0.39	0.41	0.43	0.5%
Cooking	0.10	0.11	0.12	0.12	0.13	0.14	0.15	1.2%
Clothes Dryers	0.26	0.26	0.27	0.28	0.29	0.31	0.32	0.7%
Freezers	0.08	0.08	0.08	0.08	0.09	0.09	0.09	0.6%
Lighting	0.73	0.72	0.57	0.53	0.52	0.52	0.52	-1.2%
Clothes Washers[1]	0.03	0.03	0.03	0.03	0.03	0.03	0.03	-0.5%
Dishwashers[1]	0.09	0.09	0.09	0.10	0.10	0.11	0.12	0.9%
Color Televisions and Set-Top Boxes	0.32	0.35	0.39	0.42	0.44	0.47	0.50	1.4%
Personal Computers and Related Equipment	0.15	0.17	0.19	0.19	0.19	0.21	0.21	0.9%
Furnace Fans and Boiler Circulation Pumps	0.13	0.14	0.15	0.16	0.18	0.19	0.19	1.2%
Other Uses[2]	0.86	0.89	0.94	1.07	1.21	1.34	1.46	1.9%
Delivered Energy	**4.75**	**4.71**	**4.78**	**5.02**	**5.30**	**5.58**	**5.83**	**0.8%**
Natural Gas								
Space Heating	3.21	3.38	3.20	3.27	3.31	3.32	3.33	-0.1%
Space Cooling	0.00	0.00	0.00	0.00	0.00	0.00	0.00	- -
Water Heating	1.34	1.33	1.35	1.40	1.42	1.40	1.36	0.1%
Cooking	0.22	0.22	0.22	0.23	0.23	0.24	0.24	0.4%
Clothes Dryers	0.07	0.07	0.08	0.08	0.08	0.08	0.08	0.6%
Delivered Energy	**4.84**	**5.01**	**4.85**	**4.97**	**5.04**	**5.03**	**5.01**	**0.0%**
Distillate Fuel Oil								
Space Heating	0.61	0.58	0.51	0.47	0.43	0.40	0.37	-1.6%
Water Heating	0.12	0.11	0.08	0.07	0.06	0.05	0.04	-3.3%
Delivered Energy	**0.73**	**0.68**	**0.59**	**0.53**	**0.49**	**0.45**	**0.41**	**-1.9%**
Liquefied Petroleum Gases								
Space Heating	0.22	0.19	0.16	0.14	0.14	0.13	0.12	-1.6%
Water Heating	0.09	0.09	0.06	0.05	0.05	0.04	0.04	-3.3%
Cooking	0.03	0.03	0.03	0.03	0.03	0.03	0.03	-0.7%
Other Uses[3]	0.14	0.15	0.16	0.18	0.19	0.21	0.22	1.5%
Delivered Energy	**0.48**	**0.45**	**0.41**	**0.40**	**0.40**	**0.40**	**0.40**	**-0.4%**
Marketed Renewables (wood)[4]	0.41	0.45	0.40	0.42	0.42	0.42	0.43	-0.1%
Other Fuels[5]	0.05	0.05	0.04	0.04	0.04	0.04	0.04	-1.0%

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

Key Indicators and Consumption	Reference Case							Annual Growth 2008-2035 (percent)
	2007	2008	2015	2020	2025	2030	2035	
Delivered Energy Consumption by End Use								
Space Heating	4.76	4.93	4.59	4.62	4.62	4.58	4.56	-0.3%
Space Cooling	0.91	0.77	0.83	0.87	0.92	0.96	0.99	0.9%
Water Heating	1.97	1.96	1.97	2.02	2.05	2.02	1.97	0.0%
Refrigeration	0.38	0.38	0.36	0.37	0.39	0.41	0.43	0.5%
Cooking	0.35	0.35	0.36	0.38	0.39	0.40	0.41	0.6%
Clothes Dryers	0.34	0.34	0.35	0.36	0.37	0.39	0.41	0.7%
Freezers	0.08	0.08	0.08	0.08	0.09	0.09	0.09	0.6%
Lighting	0.73	0.72	0.57	0.53	0.52	0.52	0.52	-1.2%
Clothes Washers[1]	0.03	0.03	0.03	0.03	0.03	0.03	0.03	-0.5%
Dishwashers[1]	0.09	0.09	0.09	0.10	0.10	0.11	0.12	0.9%
Color Televisions and Set-Top Boxes	0.32	0.35	0.39	0.42	0.44	0.47	0.50	1.4%
Personal Computers and Related Equipment	0.15	0.17	0.19	0.19	0.19	0.21	0.21	0.9%
Furnace Fans and Boiler Circulation Pumps	0.13	0.14	0.15	0.16	0.18	0.19	0.19	1.2%
Other Uses[6]	1.00	1.03	1.11	1.25	1.40	1.55	1.68	1.8%
Delivered Energy	**11.25**	**11.34**	**11.07**	**11.38**	**11.69**	**11.93**	**12.12**	**0.2%**
Electricity Related Losses	**10.29**	**10.20**	**10.24**	**10.65**	**11.08**	**11.45**	**11.79**	**0.5%**
Total Energy Consumption by End Use								
Space Heating	5.34	5.54	5.18	5.22	5.21	5.16	5.13	-0.3%
Space Cooling	2.88	2.45	2.62	2.72	2.83	2.93	3.01	0.8%
Water Heating	2.90	2.90	2.99	3.11	3.16	3.12	3.03	0.2%
Refrigeration	1.21	1.19	1.13	1.16	1.20	1.26	1.31	0.3%
Cooking	0.58	0.58	0.61	0.64	0.67	0.69	0.71	0.7%
Clothes Dryers	0.91	0.91	0.93	0.96	0.99	1.02	1.06	0.6%
Freezers	0.26	0.25	0.25	0.26	0.27	0.28	0.28	0.4%
Lighting	2.30	2.30	1.79	1.67	1.60	1.57	1.58	-1.4%
Clothes Washers[1]	0.11	0.11	0.09	0.08	0.08	0.09	0.09	-0.7%
Dishwashers[1]	0.30	0.29	0.29	0.30	0.32	0.34	0.36	0.7%
Color Televisions and Set-Top Boxes	1.03	1.09	1.23	1.30	1.37	1.44	1.51	1.2%
Personal Computers and Related Equipment	0.48	0.53	0.60	0.60	0.60	0.63	0.64	0.7%
Furnace Fans and Boiler Circulation Pumps	0.41	0.44	0.47	0.51	0.55	0.57	0.58	1.0%
Other Uses[6]	2.86	2.96	3.13	3.51	3.92	4.29	4.63	1.7%
Total	**21.54**	**21.54**	**21.31**	**22.03**	**22.76**	**23.38**	**23.92**	**0.4%**
Nonmarketed Renewables[7]								
Geothermal Heat Pumps	0.00	0.00	0.02	0.03	0.03	0.04	0.04	9.5%
Solar Hot Water Heating	0.00	0.00	0.00	0.00	0.00	0.01	0.01	2.1%
Solar Photovoltaic	0.00	0.00	0.04	0.05	0.05	0.05	0.05	19.0%
Wind	0.00	0.00	0.01	0.01	0.01	0.01	0.01	19.2%
Total	**0.01**	**0.01**	**0.07**	**0.09**	**0.09**	**0.10**	**0.11**	**10.4%**

[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 2007 and 2008 are model results and may differ slightly from official EIA data reports.
Sources: 2007 and 2008 based on: Energy Information Administration (EIA), *Annual Energy Review 2008*, DOE/EIA-0384(2008) (Washington, DC, June 2009). **Projections:** EIA, AEO2010 National Energy Modeling System run AEO2010R.D111809A.

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

Key Indicators and Consumption	Reference Case							Annual Growth 2008-2035 (percent)
	2007	2008	2015	2020	2025	2030	2035	
Key Indicators								
Total Floorspace (billion square feet)								
Surviving	74.9	76.4	83.0	88.8	95.1	101.5	108.0	1.3%
New Additions	2.4	2.4	2.0	2.3	2.4	2.5	2.6	0.3%
Total	**77.3**	**78.8**	**85.1**	**91.1**	**97.5**	**103.9**	**110.5**	**1.3%**
Energy Consumption Intensity (thousand Btu per square foot)								
Delivered Energy Consumption	109.2	108.9	106.3	104.3	102.6	101.1	99.8	-0.3%
Electricity Related Losses	127.8	126.9	126.0	125.0	123.4	121.5	120.0	-0.2%
Total Energy Consumption	237.0	235.8	232.3	229.3	226.0	222.6	219.8	-0.3%
Delivered Energy Consumption by Fuel								
Purchased Electricity								
Space Heating[1]	0.17	0.18	0.17	0.17	0.17	0.17	0.17	-0.1%
Space Cooling[1]	0.55	0.50	0.55	0.58	0.61	0.64	0.67	1.1%
Water Heating[1]	0.10	0.09	0.09	0.09	0.09	0.09	0.09	-0.1%
Ventilation	0.49	0.49	0.55	0.59	0.63	0.66	0.68	1.2%
Cooking	0.02	0.02	0.02	0.02	0.02	0.02	0.02	-0.1%
Lighting	1.06	1.04	1.04	1.08	1.12	1.16	1.20	0.5%
Refrigeration	0.40	0.40	0.36	0.35	0.36	0.37	0.39	-0.2%
Office Equipment (PC)	0.21	0.23	0.24	0.24	0.24	0.26	0.26	0.5%
Office Equipment (non-PC)	0.22	0.24	0.32	0.37	0.40	0.44	0.46	2.5%
Other Uses[2]	1.34	1.42	1.66	1.88	2.11	2.35	2.61	2.3%
Delivered Energy	**4.56**	**4.61**	**5.00**	**5.37**	**5.76**	**6.16**	**6.55**	**1.3%**
Natural Gas								
Space Heating[1]	1.45	1.54	1.56	1.59	1.60	1.59	1.57	0.1%
Space Cooling[1]	0.04	0.03	0.04	0.04	0.04	0.04	0.04	0.3%
Water Heating[1]	0.44	0.44	0.48	0.52	0.56	0.59	0.61	1.3%
Cooking	0.16	0.17	0.19	0.20	0.21	0.22	0.24	1.3%
Other Uses[3]	1.01	1.03	1.05	1.08	1.14	1.22	1.34	1.0%
Delivered Energy	**3.10**	**3.21**	**3.32**	**3.43**	**3.55**	**3.66**	**3.79**	**0.6%**
Distillate Fuel Oil								
Space Heating[1]	0.16	0.15	0.13	0.12	0.11	0.10	0.10	-1.6%
Water Heating[1]	0.02	0.02	0.02	0.02	0.02	0.02	0.02	-0.4%
Other Uses[4]	0.21	0.19	0.16	0.15	0.15	0.15	0.15	-1.0%
Delivered Energy	**0.38**	**0.36**	**0.31**	**0.29**	**0.28**	**0.27**	**0.26**	**-1.2%**
Marketed Renewables (biomass)	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.0%
Other Fuels[5]	0.30	0.29	0.31	0.31	0.32	0.32	0.32	0.5%
Delivered Energy Consumption by End Use								
Space Heating[1]	1.77	1.87	1.86	1.88	1.88	1.86	1.84	-0.1%
Space Cooling[1]	0.59	0.53	0.59	0.61	0.64	0.67	0.70	1.0%
Water Heating[1]	0.56	0.55	0.59	0.63	0.67	0.70	0.72	1.0%
Ventilation	0.49	0.49	0.55	0.59	0.63	0.66	0.68	1.2%
Cooking	0.19	0.19	0.21	0.22	0.24	0.25	0.26	1.2%
Lighting	1.06	1.04	1.04	1.08	1.12	1.16	1.20	0.5%
Refrigeration	0.40	0.40	0.36	0.35	0.36	0.37	0.39	-0.2%
Office Equipment (PC)	0.21	0.23	0.24	0.24	0.24	0.26	0.26	0.5%
Office Equipment (non-PC)	0.22	0.24	0.32	0.37	0.40	0.44	0.46	2.5%
Other Uses[6]	2.95	3.03	3.29	3.53	3.81	4.14	4.52	1.5%
Delivered Energy	**8.44**	**8.58**	**9.04**	**9.50**	**10.00**	**10.51**	**11.04**	**0.9%**

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

Key Indicators and Consumption	Reference Case							Annual Growth 2008-2035 (percent)
	2007	2008	2015	2020	2025	2030	2035	
Electricity Related Losses	**9.88**	**10.00**	**10.72**	**11.39**	**12.03**	**12.63**	**13.27**	**1.1%**
Total Energy Consumption by End Use								
Space Heating[1]	2.14	2.26	2.22	2.24	2.24	2.22	2.19	-0.1%
Space Cooling[1]	1.78	1.62	1.76	1.84	1.91	1.98	2.05	0.9%
Water Heating[1]	0.76	0.75	0.79	0.83	0.87	0.89	0.91	0.7%
Ventilation	1.55	1.57	1.74	1.84	1.93	2.00	2.06	1.0%
Cooking	0.24	0.24	0.26	0.27	0.28	0.29	0.30	0.9%
Lighting	3.35	3.29	3.26	3.36	3.47	3.55	3.63	0.4%
Refrigeration	1.27	1.28	1.13	1.10	1.10	1.13	1.17	-0.3%
Office Equipment (PC)	0.67	0.71	0.76	0.75	0.76	0.78	0.79	0.3%
Office Equipment (non-PC)	0.69	0.75	1.00	1.15	1.25	1.34	1.40	2.3%
Other Uses[6]	5.86	6.11	6.85	7.51	8.22	8.97	9.81	1.8%
Total	**18.32**	**18.58**	**19.77**	**20.89**	**22.03**	**23.14**	**24.30**	**1.0%**
Nonmarketed Renewable Fuels[7]								
Solar Thermal	0.02	0.02	0.03	0.03	0.03	0.03	0.03	0.7%
Solar Photovoltaic	0.00	0.00	0.01	0.01	0.01	0.01	0.02	6.4%
Wind	0.00	0.00	0.00	0.00	0.00	0.00	0.00	8.3%
Total	**0.03**	**0.03**	**0.04**	**0.04**	**0.04**	**0.05**	**0.05**	**2.3%**

[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 2007 and 2008 are model results and may differ slightly from official EIA data reports.
Sources: 2007 and 2008 based on: Energy Information Administration (EIA), *Annual Energy Review 2008*, DOE/EIA-0384(2008) (Washington, DC, June 2009). **Projections:** EIA, AEO2010 National Energy Modeling System run AEO2010R.D111809A.

Table A6. Industrial Sector Key Indicators and Consumption

Key Indicators and Consumption	Reference Case							Annual Growth 2008-2035 (percent)
	2007	2008	2015	2020	2025	2030	2035	
Key Indicators								
Value of Shipments (billion 2000 dollars)								
Manufacturing	4215	4014	4497	5006	5324	5680	6010	1.5%
Nonmanufacturing	1436	1394	1547	1644	1673	1722	1776	0.9%
Total	**5652**	**5408**	**6044**	**6651**	**6997**	**7401**	**7786**	**1.4%**
Energy Prices								
(2008 dollars per million Btu)								
Liquefied Petroleum Gases	22.01	24.20	22.49	24.86	26.12	27.38	29.25	0.7%
Motor Gasoline	18.05	16.28	25.17	27.41	28.70	30.24	32.15	2.6%
Distillate Fuel Oil	18.07	22.31	19.00	21.83	22.97	24.40	26.48	0.6%
Residual Fuel Oil	8.84	16.31	16.47	18.20	19.23	20.27	21.72	1.1%
Asphalt and Road Oil	4.53	8.23	7.13	7.95	8.43	8.93	9.76	0.6%
Natural Gas Heat and Power	6.61	8.25	5.62	5.88	6.25	7.24	8.03	-0.1%
Natural Gas Feedstocks	8.32	9.85	7.25	7.52	7.82	8.78	9.54	-0.1%
Metallurgical Coal	3.69	4.49	5.08	5.32	5.24	5.11	5.06	0.4%
Other Industrial Coal	2.48	2.84	2.69	2.66	2.63	2.66	2.71	-0.2%
Coal for Liquids	- -	- -	1.42	1.46	1.49	1.44	1.51	- -
Electricity	19.02	20.21	17.37	17.92	18.50	19.58	20.71	0.1%
(nominal dollars per million Btu)								
Liquefied Petroleum Gases	21.53	24.20	25.06	30.38	35.45	41.33	49.15	2.7%
Motor Gasoline	17.66	16.28	28.05	33.50	38.95	45.65	54.04	4.5%
Distillate Fuel Oil	17.68	22.31	21.18	26.68	31.18	36.83	44.51	2.6%
Residual Fuel Oil	8.65	16.31	18.35	22.24	26.10	30.60	36.50	3.0%
Asphalt and Road Oil	4.43	8.23	7.95	9.72	11.43	13.49	16.40	2.6%
Natural Gas Heat and Power	6.47	8.25	6.27	7.18	8.48	10.92	13.49	1.8%
Natural Gas Feedstocks	8.14	9.85	8.08	9.20	10.61	13.26	16.03	1.8%
Metallurgical Coal	3.61	4.49	5.66	6.50	7.11	7.72	8.50	2.4%
Other Industrial Coal	2.43	2.84	3.00	3.26	3.56	4.01	4.55	1.8%
Coal for Liquids	- -	- -	1.58	1.79	2.02	2.18	2.53	- -
Electricity	18.60	20.21	19.36	21.90	25.11	29.55	34.80	2.0%
Energy Consumption (quadrillion Btu)[1]								
Industrial Consumption Excluding Refining								
Liquefied Petroleum Gases Heat and Power	0.30	0.29	0.28	0.28	0.27	0.27	0.27	-0.2%
Liquefied Petroleum Gases Feedstocks	1.97	1.85	2.01	2.31	2.25	2.17	2.06	0.4%
Motor Gasoline	0.31	0.30	0.30	0.30	0.30	0.30	0.30	0.1%
Distillate Fuel Oil	1.26	1.19	1.19	1.19	1.17	1.17	1.17	-0.1%
Residual Fuel Oil	0.18	0.17	0.14	0.14	0.14	0.14	0.13	-0.9%
Petrochemical Feedstocks	1.31	1.12	1.09	0.81	0.82	0.82	0.81	-1.2%
Petroleum Coke	0.35	0.25	0.21	0.21	0.20	0.20	0.19	-1.0%
Asphalt and Road Oil	1.20	1.01	1.08	1.08	1.02	0.99	0.96	-0.2%
Miscellaneous Petroleum[2]	0.63	0.45	0.36	0.35	0.34	0.34	0.32	-1.2%
Petroleum Subtotal	7.51	6.62	6.65	6.66	6.52	6.39	6.22	-0.2%
Natural Gas Heat and Power	5.12	5.00	5.12	5.22	5.11	4.98	4.92	-0.1%
Natural Gas Feedstocks	0.56	0.57	0.55	0.56	0.52	0.48	0.45	-0.9%
Lease and Plant Fuel[3]	1.22	1.32	1.11	1.12	1.23	1.26	1.29	-0.1%
Natural Gas Subtotal	6.90	6.89	6.78	6.90	6.86	6.72	6.65	-0.1%
Metallurgical Coal and Coke[4]	0.62	0.62	0.53	0.55	0.51	0.45	0.36	-2.0%
Other Industrial Coal	1.15	1.10	1.02	1.02	1.01	1.00	0.98	-0.4%
Coal Subtotal	1.77	1.72	1.55	1.57	1.52	1.45	1.34	-0.9%
Renewables[5]	1.62	1.50	1.59	1.69	1.74	1.79	1.83	0.7%
Purchased Electricity	3.35	3.19	3.24	3.34	3.31	3.29	3.28	0.1%
Delivered Energy	**21.14**	**19.93**	**19.82**	**20.17**	**19.96**	**19.63**	**19.33**	**-0.1%**
Electricity Related Losses	7.25	6.91	6.94	7.09	6.92	6.74	6.63	-0.2%
Total	**28.39**	**26.83**	**26.76**	**27.26**	**26.88**	**26.38**	**25.96**	**-0.1%**

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

Key Indicators and Consumption	Reference Case							Annual Growth 2008-2035 (percent)
	2007	2008	2015	2020	2025	2030	2035	
Refining Consumption								
Liquefied Petroleum Gases Heat and Power	0.01	0.01	0.03	0.02	0.03	0.03	0.03	4.0%
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	0.55	0.58	0.59	0.59	0.61	0.61	0.62	0.3%
Still Gas	1.70	1.73	1.74	1.70	1.68	1.77	1.80	0.2%
Miscellaneous Petroleum[2]	0.02	0.04	0.03	0.03	0.03	0.03	0.03	-0.7%
Petroleum Subtotal	2.30	2.36	2.38	2.34	2.35	2.44	2.48	0.2%
Natural Gas Heat and Power	1.13	1.27	1.41	1.46	1.51	1.48	1.54	0.7%
Natural-Gas-to-Liquids Heat and Power	0.00	0.00	0.00	0.00	0.00	0.00	0.00	- -
Natural Gas Subtotal	1.13	1.27	1.41	1.46	1.51	1.48	1.54	0.7%
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	0.16	0.24	0.34	0.45	0.55	27.6%
Coal Subtotal	0.06	0.06	0.22	0.30	0.40	0.51	0.61	8.7%
Biofuels Heat and Coproducts[6]	0.40	1.03	0.77	1.02	1.49	1.90	2.56	3.4%
Purchased Electricity	0.16	0.16	0.16	0.17	0.18	0.18	0.19	0.5%
Delivered Energy	**4.05**	**4.89**	**4.94**	**5.28**	**5.93**	**6.51**	**7.38**	**1.5%**
Electricity Related Losses	0.35	0.35	0.35	0.36	0.37	0.37	0.38	0.3%
Total	**4.40**	**5.24**	**5.29**	**5.64**	**6.30**	**6.88**	**7.76**	**1.5%**
Total Industrial Sector Consumption								
Liquefied Petroleum Gases Heat and Power	0.30	0.30	0.31	0.30	0.30	0.29	0.30	-0.0%
Liquefied Petroleum Gases Feedstocks	1.97	1.85	2.01	2.31	2.25	2.17	2.06	0.4%
Motor Gasoline	0.31	0.30	0.30	0.30	0.30	0.30	0.30	0.1%
Distillate Fuel Oil	1.26	1.19	1.19	1.19	1.17	1.17	1.17	-0.1%
Residual Fuel Oil	0.19	0.18	0.14	0.14	0.14	0.14	0.13	-1.1%
Petrochemical Feedstocks	1.31	1.12	1.09	0.81	0.82	0.82	0.81	-1.2%
Petroleum Coke	0.91	0.83	0.80	0.80	0.82	0.81	0.81	-0.1%
Asphalt and Road Oil	1.20	1.01	1.08	1.08	1.02	0.99	0.96	-0.2%
Still Gas	1.70	1.73	1.74	1.70	1.68	1.77	1.80	0.2%
Miscellaneous Petroleum[2]	0.65	0.49	0.39	0.38	0.37	0.37	0.35	-1.2%
Petroleum Subtotal	9.80	8.99	9.04	9.01	8.87	8.82	8.70	-0.1%
Natural Gas Heat and Power	6.25	6.27	6.53	6.67	6.62	6.46	6.47	0.1%
Natural-Gas-to-Liquids Heat and Power	0.00	0.00	0.00	0.00	0.00	0.00	0.00	- -
Natural Gas Feedstocks	0.56	0.57	0.55	0.56	0.52	0.48	0.45	-0.9%
Lease and Plant Fuel[3]	1.22	1.32	1.11	1.12	1.23	1.26	1.29	-0.1%
Natural Gas Subtotal	8.03	8.16	8.19	8.35	8.37	8.20	8.20	0.0%
Metallurgical Coal and Coke[4]	0.62	0.62	0.53	0.55	0.51	0.45	0.36	-2.0%
Other Industrial Coal	1.21	1.17	1.07	1.08	1.07	1.06	1.04	-0.4%
Coal-to-Liquids Heat and Power	0.00	0.00	0.16	0.24	0.34	0.45	0.55	27.6%
Coal Subtotal	1.83	1.79	1.76	1.88	1.92	1.96	1.95	0.3%
Biofuels Heat and Coproducts[6]	0.40	1.03	0.77	1.02	1.49	1.90	2.56	3.4%
Renewables[5]	1.62	1.50	1.59	1.69	1.74	1.79	1.83	0.7%
Purchased Electricity	3.51	3.35	3.40	3.51	3.49	3.47	3.47	0.1%
Delivered Energy	**25.19**	**24.81**	**24.76**	**25.45**	**25.88**	**26.14**	**26.70**	**0.3%**
Electricity Related Losses	7.60	7.26	7.29	7.45	7.29	7.12	7.01	-0.1%
Total	**32.79**	**32.07**	**32.05**	**32.90**	**33.18**	**33.26**	**33.72**	**0.2%**

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

Key Indicators and Consumption	Reference Case							Annual Growth 2008-2035 (percent)
	2007	2008	2015	2020	2025	2030	2035	
Energy Consumption per dollar of Shipment (thousand Btu per 2000 dollars)								
Liquefied Petroleum Gases Heat and Power	0.05	0.05	0.05	0.05	0.04	0.04	0.04	-1.3%
Liquefied Petroleum Gases Feedstocks	0.35	0.34	0.33	0.35	0.32	0.29	0.26	-0.9%
Motor Gasoline	0.05	0.05	0.05	0.05	0.04	0.04	0.04	-1.3%
Distillate Fuel Oil	0.22	0.22	0.20	0.18	0.17	0.16	0.15	-1.4%
Residual Fuel Oil	0.03	0.03	0.02	0.02	0.02	0.02	0.02	-2.5%
Petrochemical Feedstocks	0.23	0.21	0.18	0.12	0.12	0.11	0.10	-2.5%
Petroleum Coke	0.16	0.15	0.13	0.12	0.12	0.11	0.10	-1.4%
Asphalt and Road Oil	0.21	0.19	0.18	0.16	0.15	0.13	0.12	-1.5%
Still Gas	0.30	0.32	0.29	0.26	0.24	0.24	0.23	-1.2%
Miscellaneous Petroleum[2]	0.12	0.09	0.06	0.06	0.05	0.05	0.05	-2.5%
Petroleum Subtotal	1.73	1.66	1.50	1.35	1.27	1.19	1.12	-1.5%
Natural Gas Heat and Power	1.11	1.16	1.08	1.00	0.95	0.87	0.83	-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 Feedstocks	0.10	0.10	0.09	0.08	0.07	0.06	0.06	-2.2%
Lease and Plant Fuel[3]	0.22	0.24	0.18	0.17	0.18	0.17	0.17	-1.4%
Natural Gas Subtotal	1.42	1.51	1.36	1.26	1.20	1.11	1.05	-1.3%
Metallurgical Coal and Coke[4]	0.11	0.11	0.09	0.08	0.07	0.06	0.05	-3.3%
Other Industrial Coal	0.21	0.22	0.18	0.16	0.15	0.14	0.13	-1.8%
Coal-to-Liquids Heat and Power	0.00	0.00	0.03	0.04	0.05	0.06	0.07	25.9%
Coal Subtotal	0.32	0.33	0.29	0.28	0.28	0.26	0.25	-1.0%
Biofuels Heat and Coproducts[6]	0.07	0.19	0.13	0.15	0.21	0.26	0.33	2.0%
Renewables[5]	0.29	0.28	0.26	0.25	0.25	0.24	0.24	-0.6%
Purchased Electricity	0.62	0.62	0.56	0.53	0.50	0.47	0.45	-1.2%
Delivered Energy	**4.46**	**4.59**	**4.10**	**3.83**	**3.70**	**3.53**	**3.43**	**-1.1%**
Electricity Related Losses	1.34	1.34	1.21	1.12	1.04	0.96	0.90	-1.5%
Total	**5.80**	**5.93**	**5.30**	**4.95**	**4.74**	**4.49**	**4.33**	**-1.2%**
Industrial Combined Heat and Power								
Capacity (gigawatts)	25.80	25.78	31.32	35.76	44.54	52.39	56.45	2.9%
Generation (billion kilowatthours)	142.17	136.65	175.43	208.16	273.39	331.57	362.91	3.7%

[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.
[6]The energy content of biofuels feedstock minus the energy content of liquid fuel produced.
Btu = British thermal unit.
- - = Not applicable.
Note: Totals may not equal sum of components due to independent rounding. Data for 2007 and 2008 are model results and may differ slightly from official EIA data reports.
Sources: 2007 and 2008 prices for motor gasoline and distillate fuel oil are based on: Energy Information Administration (EIA), *Petroleum Marketing Annual 2008*, DOE/EIA-0487(2008) (Washington, DC, August 2009). 2007 and 2008 petrochemical feedstock and asphalt and road oil prices are based on: EIA, *State Energy Data Report 2007*, DOE/EIA-0214(2007) (Washington, DC, August 2009). 2007 and 2008 coal prices are based on: EIA, *Quarterly Coal Report, October-December 2008*, DOE/EIA-0121(2008/4Q) (Washington, DC, March 2009) and EIA, AEO2010 National Energy Modeling System run AEO2010R.D111809A. 2007 and 2008 electricity prices: EIA, *Annual Energy Review 2008*, DOE/EIA-0384(2008) (Washington, DC, June 2009). 2007 and 2008 natural gas prices are based on: EIA, *Manufacturing Energy Consumption Survey* and industrial and wellhead prices from the *Natural Gas Annual 2007*, DOE/EIA-0131(2007) (Washington, DC, January 2009) and the *Natural Gas Monthly*, DOE/EIA-0130(2009/07) (Washington, DC, July 2009). 2007 refining consumption values are based on: *Petroleum Supply Annual 2007,* DOE/EIA-0340(2007)/1 (Washington, DC, July 2008). 2008 refining consumption based on: *Petroleum Supply Annual 2008,* DOE/EIA-0340(2008)/1 (Washington, DC, June 2009). Other 2007 and 2008 consumption values are based on: EIA, *Annual Energy Review 2008*, DOE/EIA-0384(2008) (Washington, DC, June 2009). 2007 and 2008 shipments: IHS Global Insight Industry model, August 2009. **Projections:** EIA, AEO2010 National Energy Modeling System run AEO2010R.D111809A.

Table A7. Transportation Sector Key Indicators and Delivered Energy Consumption

Key Indicators and Consumption	Reference Case							Annual Growth 2008-2035 (percent)
	2007	2008	2015	2020	2025	2030	2035	
Key Indicators								
Travel Indicators								
(billion vehicle miles traveled)								
Light-Duty Vehicles less than 8,500 pounds	2746	2676	2916	3193	3554	3891	4203	1.7%
Commercial Light Trucks[1]	74	70	78	85	92	99	105	1.5%
Freight Trucks greater than 10,000 pounds	241	227	248	278	304	333	363	1.7%
(billion seat miles available)								
Air	1040	1030	1163	1264	1341	1408	1470	1.3%
(billion ton miles traveled)								
Rail	1771	1806	1881	2011	2108	2187	2257	0.8%
Domestic Shipping	584	576	587	617	643	667	691	0.7%
Energy Efficiency Indicators								
(miles per gallon)								
New Light-Duty Vehicle CAFE Standard[2]	24.8	25.0	32.5	35.2	35.5	35.6	35.8	1.3%
New Car[2]	28.0	28.0	37.4	40.0	40.0	40.0	40.0	1.3%
New Light Truck[2]	22.2	22.3	27.9	29.7	29.7	29.7	29.7	1.1%
Compliance New Light-Duty Vehicle[3]	27.4	27.6	32.0	35.6	37.2	38.5	40.0	1.4%
New Car[3]	32.1	32.2	37.1	40.3	41.5	42.8	44.2	1.2%
New Light Truck[3]	23.7	23.7	27.4	30.2	31.5	32.6	33.7	1.3%
Tested New Light-Duty Vehicle[4]	27.4	27.6	30.8	34.4	35.9	37.3	38.8	1.3%
New Car[4]	32.1	32.2	35.8	39.1	40.2	41.5	43.0	1.1%
New Light Truck[4]	23.7	23.7	26.2	29.0	30.3	31.4	32.5	1.2%
On-Road New Light-Duty Vehicle[5]	22.7	22.9	25.6	28.7	30.0	31.3	32.5	1.3%
New Car[5]	26.2	26.3	29.5	32.3	33.5	34.8	36.0	1.2%
New Light Truck[5]	19.9	19.9	22.0	24.3	25.4	26.3	27.3	1.2%
Light-Duty Stock[6]	20.4	20.9	22.3	24.3	26.2	28.0	29.3	1.3%
New Commercial Light Truck[1]	15.1	15.2	16.3	17.6	18.2	18.6	19.1	0.8%
Stock Commercial Light Truck[1]	14.1	14.3	15.1	16.2	17.2	18.0	18.5	1.0%
Freight Truck	6.0	6.0	6.3	6.6	6.8	6.9	7.0	0.6%
(seat miles per gallon)								
Aircraft	61.6	61.8	63.0	64.4	65.9	67.8	69.8	0.5%
(ton miles per thousand Btu)								
Rail	3.1	3.1	3.2	3.2	3.2	3.2	3.2	0.1%
Domestic Shipping	2.0	2.0	2.0	2.0	2.0	2.0	2.1	0.2%
Energy Use by Mode (quadrillion Btu)								
Light-Duty Vehicles	16.62	16.06	16.27	16.28	16.75	17.21	17.73	0.4%
Commercial Light Trucks[1]	0.65	0.61	0.64	0.66	0.67	0.69	0.71	0.6%
Bus Transportation	0.26	0.26	0.28	0.30	0.31	0.33	0.35	1.1%
Freight Trucks	5.01	4.72	4.93	5.26	5.58	6.00	6.46	1.2%
Rail, Passenger	0.05	0.05	0.05	0.05	0.06	0.06	0.06	1.2%
Rail, Freight	0.61	0.58	0.60	0.64	0.66	0.68	0.70	0.7%
Shipping, Domestic	0.30	0.29	0.30	0.31	0.32	0.33	0.33	0.5%
Shipping, International	0.96	0.90	0.91	0.91	0.92	0.92	0.93	0.1%
Recreational Boats	0.25	0.25	0.26	0.27	0.28	0.29	0.29	0.6%
Air	2.75	2.64	2.78	2.99	3.12	3.21	3.28	0.8%
Military Use	0.71	0.71	0.66	0.67	0.69	0.70	0.72	0.1%
Lubricants	0.15	0.14	0.14	0.15	0.15	0.15	0.15	0.3%
Pipeline Fuel	0.64	0.64	0.61	0.63	0.72	0.74	0.74	0.5%
Total	**28.96**	**27.85**	**28.42**	**29.12**	**30.21**	**31.30**	**32.46**	**0.6%**

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

Key Indicators and Consumption	Reference Case							Annual Growth 2008-2035 (percent)
	2007	2008	2015	2020	2025	2030	2035	
Energy Use by Mode								
(million barrels per day oil equivalent)								
Light-Duty Vehicles	8.82	8.57	8.76	8.83	9.14	9.45	9.93	0.5%
Commercial Light Trucks[1]	0.33	0.31	0.33	0.34	0.34	0.35	0.36	0.6%
Bus Transportation	0.17	0.18	0.21	0.25	0.30	0.34	0.40	3.1%
Freight Trucks	2.41	2.27	2.37	2.53	2.68	2.89	3.11	1.2%
Rail, Passenger	0.02	0.02	0.02	0.03	0.03	0.03	0.03	1.2%
Rail, Freight	0.29	0.27	0.28	0.30	0.32	0.33	0.33	0.7%
Shipping, Domestic	0.14	0.14	0.14	0.14	0.15	0.15	0.16	0.5%
Shipping, International	0.42	0.39	0.40	0.40	0.40	0.41	0.41	0.1%
Recreational Boats	0.13	0.13	0.14	0.15	0.15	0.15	0.16	0.7%
Air	1.33	1.28	1.35	1.45	1.51	1.55	1.59	0.8%
Military Use	0.34	0.34	0.32	0.32	0.33	0.34	0.35	0.1%
Lubricants	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.3%
Pipeline Fuel	0.32	0.33	0.31	0.32	0.36	0.37	0.38	0.5%
Total	**14.80**	**14.30**	**14.70**	**15.13**	**15.77**	**16.43**	**17.27**	**0.7%**

[1]Commercial trucks 8,500 to 10,000 pounds.
[2]CAFE standard based on projected new vehicle sales.
[3]Includes CAFE credits for alternative fueled vehicle sales, but does not include banked credits used for compliance.
[4]Environmental Protection Agency rated miles per gallon.
[5]Tested new vehicle efficiency revised for on-road performance.
[6]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 2007 and 2008 are model results and may differ slightly from official EIA data reports.

Sources: 2007 and 2008: Energy Information Administration (EIA), *Natural Gas Annual 2007*, DOE/EIA-0131(2007) (Washington, DC, January 2009); EIA, *Annual Energy Review 2008*, DOE/EIA-0384(2008) (Washington, DC, June 2009); Federal Highway Administration, *Highway Statistics 2007* (Washington, DC, October 2008); Oak Ridge National Laboratory, *Transportation Energy Data Book: Edition 28 and Annual* (Oak Ridge, TN, 2009); National Highway Traffic and Safety Administration, *Summary of Fuel Economy Performance* (Washington, DC, January 15, 2008); U.S. Department of Commerce, Bureau of the Census, “Vehicle Inventory and Use Survey,” EC97TV (Washington, DC, December 2004); EIA, Alternatives to Traditional Transportation Fuels 2006 (Part II - User and Fuel Data), May 2008; EIA, *State Energy Data Report 2007*, DOE/EIA-0214(2007) (Washington, DC, August 2009); U.S. Department of Transportation, Research and Special Programs Administration, *Air Carrier Statistics Monthly, December 2008/2007* (Washington, DC, 2008); EIA, *Fuel Oil and Kerosene Sales 2007*, DOE/EIA-0535(2007) (Washington, DC, December 2008); and United States Department of Defense, Defense Fuel Supply Center. **Projections:** EIA, AEO2010 National Energy Modeling System run AEO2010R.D111809A.

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

Supply, Disposition, and Prices	Reference Case							Annual Growth 2008-2035 (percent)
	2007	2008	2015	2020	2025	2030	2035	
Generation by Fuel Type								
Electric Power Sector[1]								
Power Only[2]								
Coal	1962	1939	1977	2026	2075	2132	2222	0.5%
Petroleum	57	39	41	42	43	43	44	0.4%
Natural Gas[3]	686	682	507	568	650	778	833	0.7%
Nuclear Power	806	806	834	883	886	886	898	0.4%
Pumped Storage/Other[4]	0	1	1	1	1	1	1	-1.3%
Renewable Sources[5]	315	334	587	626	656	666	683	2.7%
Distributed Generation (Natural Gas)	0	0	0	0	0	0	0	- -
Total	**3827**	**3801**	**3946**	**4146**	**4311**	**4506**	**4680**	**0.8%**
Combined Heat and Power[6]								
Coal	36	37	30	31	31	32	32	-0.6%
Petroleum	4	4	0	0	0	0	0	-7.9%
Natural Gas	129	117	97	101	109	107	111	-0.2%
Renewable Sources	4	4	3	5	5	5	5	0.2%
Total	**178**	**165**	**130**	**137**	**145**	**144**	**148**	**-0.4%**
Total Net Generation	**4005**	**3966**	**4077**	**4283**	**4456**	**4650**	**4828**	**0.7%**
Less Direct Use	34	33	33	34	34	34	33	0.0%
Net Available to the Grid	**3971**	**3933**	**4043**	**4249**	**4422**	**4617**	**4794**	**0.7%**
End-Use Generation[7]								
Coal	18	19	31	35	40	46	51	3.8%
Petroleum	4	3	5	5	5	5	5	1.5%
Natural Gas	82	80	86	98	112	129	149	2.3%
Other Gaseous Fuels[8]	5	5	16	15	15	16	16	4.0%
Renewable Sources[9]	34	35	59	82	135	181	204	6.8%
Other[10]	10	8	7	7	7	7	7	-0.3%
Total	**154**	**150**	**204**	**243**	**314**	**383**	**431**	**4.0%**
Less Direct Use	124	119	165	192	243	295	327	3.8%
Total Sales to the Grid	**30**	**30**	**39**	**50**	**71**	**89**	**104**	**4.7%**
Total Electricity Generation by Fuel								
Coal	2017	1995	2037	2093	2147	2210	2305	0.5%
Petroleum	65	45	46	47	48	48	49	0.3%
Natural Gas	897	879	690	767	871	1015	1093	0.8%
Nuclear Power	806	806	834	883	886	886	898	0.4%
Renewable Sources[5,9]	353	373	649	713	795	852	891	3.3%
Other[11]	20	17	23	23	23	23	23	1.2%
Total Electricity Generation	**4159**	**4116**	**4280**	**4525**	**4769**	**5034**	**5259**	**0.9%**
Total Net Generation to the Grid	**4001**	**3963**	**4082**	**4300**	**4493**	**4705**	**4898**	**0.8%**
Net Imports	**31**	**33**	**20**	**20**	**22**	**20**	**25**	**-0.9%**
Electricity Sales by Sector								
Residential	1392	1379	1400	1471	1553	1637	1707	0.8%
Commercial	1336	1352	1466	1573	1687	1805	1921	1.3%
Industrial	1028	982	997	1029	1023	1017	1016	0.1%
Transportation	6	7	7	9	11	13	16	3.5%
Total	**3763**	**3720**	**3870**	**4083**	**4274**	**4472**	**4660**	**0.8%**
Direct Use	158	152	198	226	277	328	361	3.2%
Total Electricity Use	**3921**	**3873**	**4068**	**4308**	**4550**	**4801**	**5021**	**1.0%**

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

Supply, Disposition, and Prices	Reference Case							Annual Growth 2008-2035 (percent)
	2007	2008	2015	2020	2025	2030	2035	
End-Use Prices								
(2008 cents per kilowatthour)								
Residential	10.9	11.4	10.7	10.9	11.0	11.4	11.8	0.2%
Commercial	9.8	10.4	9.1	9.3	9.5	9.9	10.4	-0.0%
Industrial	6.5	6.9	5.9	6.1	6.3	6.7	7.1	0.1%
Transportation	10.9	11.5	9.8	9.7	9.8	10.6	11.3	-0.1%
All Sectors Average	**9.3**	**9.8**	**8.9**	**9.0**	**9.3**	**9.7**	**10.2**	**0.1%**
(nominal cents per kilowatthour)								
Residential	10.6	11.4	11.9	13.3	14.9	17.2	19.9	2.1%
Commercial	9.6	10.4	10.1	11.3	12.8	14.9	17.4	1.9%
Industrial	6.3	6.9	6.6	7.5	8.6	10.1	11.9	2.0%
Transportation	10.7	11.5	10.9	11.9	13.3	16.0	19.1	1.9%
All Sectors Average	**9.1**	**9.8**	**9.9**	**11.1**	**12.6**	**14.7**	**17.1**	**2.1%**
Prices by Service Category								
(2008 cents per kilowatthour)								
Generation	6.2	6.7	5.5	5.8	6.1	6.5	7.0	0.1%
Transmission	0.7	0.7	0.9	0.9	0.9	0.9	0.9	1.1%
Distribution	2.4	2.4	2.5	2.5	2.4	2.4	2.4	-0.0%
(nominal cents per kilowatthour)								
Generation	6.0	6.7	6.2	7.1	8.2	9.8	11.7	2.1%
Transmission	0.7	0.7	1.0	1.1	1.2	1.3	1.5	3.0%
Distribution	2.4	2.4	2.8	3.0	3.3	3.6	3.9	1.9%
Electric Power Sector Emissions[1]								
Sulfur Dioxide (million tons)	8.93	7.61	4.69	4.23	3.79	3.70	3.77	-2.6%
Nitrogen Oxide (million tons)	3.29	3.00	2.05	2.02	2.04	2.05	2.07	-1.4%
Mercury (tons)	47.02	45.84	30.48	30.22	30.24	30.45	30.47	-1.5%

[1]Includes electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public.
[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 2007 and 2008 are model results and may differ slightly from official EIA data reports.
Sources: 2007 and 2008 electric power sector generation; sales to utilities; net imports; electricity sales; and emissions: Energy Information Administration (EIA), *Annual Energy Review 2008*, DOE/EIA-0384(2008) (Washington, DC, June 2009), and supporting databases. 2007 and 2008 prices: EIA, AEO2010 National Energy Modeling System run AEO2010R.D111809A. **Projections**: EIA, AEO2010 National Energy Modeling System run AEO2010R.D111809A.

Table A9. Electricity Generating Capacity
(Gigawatts)

Net Summer Capacity[1]	Reference Case							Annual Growth 2008-2035 (percent)
	2007	2008	2015	2020	2025	2030	2035	
Electric Power Sector[2]								
Power Only[3]								
Coal	304.4	303.8	315.2	315.7	315.7	318.7	324.5	0.2%
Oil and Natural Gas Steam[4]	116.2	115.5	90.8	86.8	86.8	86.8	85.8	-1.1%
Combined Cycle	150.7	156.4	168.5	168.5	175.2	201.1	211.6	1.1%
Combustion Turbine/Diesel	130.3	131.7	130.3	133.5	146.3	151.8	172.5	1.0%
Nuclear Power[5]	100.5	100.6	104.5	110.9	110.9	110.9	112.9	0.4%
Pumped Storage	21.8	21.8	21.8	21.8	21.8	21.8	21.8	0.0%
Fuel Cells	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
Renewable Sources[6]	100.5	109.4	154.0	154.2	156.3	159.5	167.8	1.6%
Distributed Generation[7]	0.0	0.0	0.0	0.0	0.0	0.0	0.3	- -
Total	**924.5**	**939.2**	**985.2**	**991.5**	**1013.0**	**1050.7**	**1097.1**	**0.6%**
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	31.7	32.3	32.3	32.3	32.3	32.3	0.1%
Combustion Turbine/Diesel	2.9	2.9	2.9	2.9	2.9	2.9	2.9	0.0%
Renewable Sources[6]	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.0%
Total	**40.3**	**40.3**	**40.8**	**40.8**	**40.8**	**40.8**	**40.8**	**0.0%**
Cumulative Planned Additions[9]								
Coal	0.0	0.0	15.6	15.6	15.6	15.6	15.6	- -
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	13.0	13.0	13.0	13.0	13.0	- -
Combustion Turbine/Diesel	0.0	0.0	4.1	4.1	4.1	4.1	4.1	- -
Nuclear Power	0.0	0.0	1.2	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	1.1	1.2	1.3	1.4	1.5	- -
Distributed Generation[7]	0.0	0.0	0.0	0.0	0.0	0.0	0.0	- -
Total	**0.0**	**0.0**	**35.0**	**35.1**	**35.2**	**35.3**	**35.4**	**- -**
Cumulative Unplanned Additions[9]								
Coal	0.0	0.0	0.0	2.0	2.0	5.0	10.8	- -
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	6.7	32.6	43.0	- -
Combustion Turbine/Diesel	0.0	0.0	3.6	7.0	19.8	25.6	46.3	- -
Nuclear Power	0.0	0.0	0.0	5.2	5.2	5.2	7.2	- -
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	43.6	43.7	45.7	48.8	57.0	- -
Distributed Generation[7]	0.0	0.0	0.0	0.0	0.0	0.0	0.3	- -
Total	**0.0**	**0.0**	**47.2**	**58.0**	**79.4**	**117.2**	**164.6**	**- -**
Cumulative Electric Power Sector Additions	**0.0**	**0.0**	**82.3**	**93.1**	**114.6**	**152.5**	**200.0**	**- -**
Cumulative Retirements[10]								
Coal	0.0	0.0	4.3	5.7	5.7	5.7	5.7	- -
Oil and Natural Gas Steam[4]	0.0	0.0	24.7	28.7	28.7	28.7	29.7	- -
Combined Cycle	0.0	0.0	0.4	0.4	0.4	0.4	0.4	- -
Combustion Turbine/Diesel	0.0	0.0	9.1	9.3	9.3	9.6	9.6	- -
Nuclear Power	0.0	0.0	0.0	0.0	0.0	0.0	0.0	- -
Pumped Storage	0.0	0.0	0.0	0.0	0.0	0.0	0.0	- -
Fuel Cells	0.0	0.0	0.0	0.0	0.0	0.0	0.0	- -
Renewable Sources[6]	0.0	0.0	0.1	0.1	0.1	0.1	0.1	- -
Total	**0.0**	**0.0**	**38.5**	**44.2**	**44.2**	**44.5**	**45.5**	**- -**
Total Electric Power Sector Capacity	**964.9**	**979.5**	**1026.0**	**1032.3**	**1053.8**	**1091.5**	**1137.9**	**0.6%**

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

Net Summer Capacity[1]	Reference Case 2007	2008	2015	2020	2025	2030	2035	Annual Growth 2008-2035 (percent)
End-Use Generators[11]								
Coal	3.5	3.5	5.1	5.6	6.3	7.0	7.7	3.0%
Petroleum	0.9	0.9	1.2	1.2	1.2	1.2	1.2	1.2%
Natural Gas	14.7	14.7	15.2	16.7	18.6	20.9	23.7	1.8%
Other Gaseous Fuels	2.0	2.0	3.9	3.8	3.8	3.8	3.9	2.5%
Renewable Sources[6]	6.4	6.8	16.9	21.9	29.3	36.5	41.0	6.9%
Other	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.1%
Total	**28.3**	**28.5**	**43.0**	**50.0**	**59.9**	**70.2**	**78.1**	**3.8%**
Cumulative Capacity Additions[9]	**0.0**	**0.0**	**14.4**	**21.4**	**31.4**	**41.6**	**49.6**	**- -**

[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 4.0 gigawatts of uprates through 2035.
[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, 2008.
[10]Cumulative retirements after December 31, 2008.
[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 2007 and 2008 are model results and may differ slightly from official EIA data reports.
Sources: 2007 and 2008 capacity and projected planned additions: Energy Information Administration (EIA), Form EIA-860, "Annual Electric Generator Report" (preliminary). **Projections:** EIA, AEO2010 National Energy Modeling System run AEO2010R.D111809A.

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

Electricity Trade	Reference Case							Annual Growth 2008-2035 (percent)
	2007	2008	2015	2020	2025	2030	2035	
Interregional Electricity Trade								
Gross Domestic Sales								
Firm Power	124.5	122.9	110.9	81.8	44.9	37.6	37.6	-4.3%
Economy	133.1	192.8	145.3	143.0	186.1	185.0	182.2	-0.2%
Total	**257.6**	**315.7**	**256.2**	**224.8**	**231.0**	**222.6**	**219.7**	**-1.3%**
Gross Domestic Sales (million 2008 dollars)								
Firm Power	7292.7	7197.8	6495.1	4788.3	2632.1	2200.9	2200.9	-4.3%
Economy	8933.0	15234.5	6985.2	7455.4	9667.1	10958.5	11841.1	-0.9%
Total	**16225.7**	**22432.3**	**13480.3**	**12243.7**	**12299.2**	**13159.4**	**14041.9**	**-1.7%**
International Electricity Trade								
Imports from Canada and Mexico								
Firm Power	15.8	19.9	12.0	7.3	1.5	0.4	0.4	-13.6%
Economy	35.6	37.0	29.2	33.1	39.2	37.0	41.9	0.5%
Total	**51.4**	**56.9**	**41.2**	**40.4**	**40.8**	**37.4**	**42.2**	**-1.1%**
Exports to Canada and Mexico								
Firm Power	3.9	3.3	0.9	0.5	0.1	0.0	0.0	- -
Economy	16.2	21.0	20.4	19.4	18.5	17.7	16.8	-0.8%
Total	**20.1**	**24.4**	**21.3**	**20.0**	**18.6**	**17.7**	**16.8**	**-1.4%**

- - = Not applicable.
Note: Totals may not equal sum of components due to independent rounding. Data for 2007 and 2008 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: 2007 and 2008 interregional firm electricity trade data: North American Electric Reliability Council (NERC), Electricity Sales and Demand Database 2007. 2007 and 2008 Mexican electricity trade data: Energy Information Administration (EIA), *Annual Energy Review 2008* DOE/EIA-0384(2008) (Washington, DC, June 2009). 2007 Canadian international electricity trade data: National Energy Board, *Canadian Energy Overview 2007* (May 2008). 2008 Canadian electricity trade data: National Energy Board, *Canadian Energy Overview 2008* (May 2009). **Projections:** EIA, AEO2010 National Energy Modeling System run AEO2010R.D111809A.

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

Supply and Disposition	Reference Case							Annual Growth 2008-2035 (percent)
	2007	2008	2015	2020	2025	2030	2035	
Crude Oil								
Domestic Crude Production[1]	5.08	4.96	5.77	6.13	6.13	6.20	6.27	0.9%
Alaska	0.72	0.69	0.49	0.68	0.74	0.58	0.45	-1.6%
Lower 48 States	4.36	4.28	5.28	5.45	5.39	5.62	5.83	1.2%
Net Imports	10.00	9.75	8.88	8.51	8.60	8.65	8.65	-0.4%
Gross Imports	10.03	9.78	8.91	8.54	8.63	8.69	8.68	-0.4%
Exports	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.5%
Other Crude Supply[2]	0.09	-0.06	0.00	0.00	0.00	0.00	0.00	- -
Total Crude Supply	**15.17**	**14.66**	**14.66**	**14.64**	**14.73**	**14.85**	**14.92**	**0.1%**
Other Petroleum Supply	**4.97**	**4.10**	**4.05**	**4.08**	**4.01**	**3.96**	**3.98**	**-0.1%**
Natural Gas Plant Liquids	1.78	1.78	1.77	1.80	1.74	1.79	1.83	0.1%
Net Product Imports	2.09	1.39	1.24	1.16	1.10	1.01	1.02	-1.1%
Gross Refined Product Imports[3]	1.94	1.54	1.23	1.25	1.25	1.18	1.22	-0.9%
Unfinished Oil Imports	0.72	0.76	0.81	0.81	0.82	0.84	0.85	0.4%
Blending Component Imports	0.75	0.79	0.80	0.81	0.82	0.83	0.84	0.2%
Exports	1.32	1.71	1.60	1.71	1.79	1.84	1.89	0.4%
Refinery Processing Gain[4]	1.00	1.00	1.04	1.13	1.17	1.16	1.13	0.5%
Product Stock Withdrawal	0.10	-0.07	0.00	0.00	0.00	0.00	0.00	- -
Other Non-petroleum Supply	**0.57**	**0.78**	**1.42**	**1.71**	**2.11**	**2.55**	**3.11**	**5.2%**
Supply from Renewable Sources	0.48	0.71	1.10	1.28	1.63	2.02	2.58	4.9%
Ethanol	0.45	0.65	0.95	1.07	1.21	1.37	1.82	3.9%
Domestic Production	0.43	0.61	0.91	1.01	1.10	1.12	1.49	3.4%
Net Imports	0.02	0.05	0.04	0.05	0.11	0.25	0.33	7.4%
Biodiesel	0.03	0.05	0.11	0.11	0.11	0.13	0.13	3.9%
Domestic Production	0.03	0.05	0.11	0.11	0.11	0.13	0.13	3.9%
Net Imports	0.00	0.00	0.00	0.00	0.00	0.00	0.00	- -
Other Biomass-derived Liquids[5]	0.00	0.01	0.04	0.10	0.31	0.53	0.63	16.5%
Liquids from Gas	0.00	0.00	0.00	0.00	0.00	0.00	0.00	- -
Liquids from Coal	0.00	0.00	0.07	0.11	0.15	0.20	0.24	- -
Other[6]	0.09	0.07	0.25	0.32	0.33	0.33	0.29	5.3%
Total Primary Supply[7]	**20.71**	**19.54**	**20.13**	**20.44**	**20.86**	**21.36**	**22.00**	**0.4%**
Liquid Fuels Consumption								
by Fuel								
Liquefied Petroleum Gases	2.09	1.95	2.15	2.37	2.33	2.27	2.19	0.4%
E85[8]	0.00	0.00	0.01	0.18	0.36	0.56	1.20	23.3%
Motor Gasoline[9]	9.29	8.99	9.37	9.24	9.32	9.35	9.06	0.0%
Jet Fuel[10]	1.62	1.54	1.57	1.68	1.75	1.80	1.84	0.7%
Distillate Fuel Oil[11]	4.20	3.94	4.08	4.24	4.41	4.65	4.91	0.8%
Diesel	3.47	3.44	3.56	3.75	3.93	4.20	4.48	1.0%
Residual Fuel Oil	0.72	0.62	0.66	0.66	0.66	0.67	0.67	0.3%
Other[12]	2.74	2.47	2.35	2.19	2.17	2.19	2.18	-0.5%
by Sector								
Residential and Commercial	1.05	0.98	0.89	0.85	0.83	0.81	0.79	-0.8%
Industrial[13]	5.16	4.75	4.82	4.89	4.81	4.76	4.67	-0.1%
Transportation	14.39	13.88	14.27	14.61	15.14	15.69	16.38	0.6%
Electric Power[14]	0.29	0.21	0.20	0.21	0.21	0.22	0.22	0.2%
Total	**20.65**	**19.53**	**20.18**	**20.56**	**20.99**	**21.48**	**22.06**	**0.5%**
Discrepancy[15]	**0.06**	**0.01**	**-0.05**	**-0.13**	**-0.13**	**-0.12**	**-0.06**	**- -**

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

Supply and Disposition	Reference Case							Annual Growth 2008-2035 (percent)
	2007	2008	2015	2020	2025	2030	2035	
Domestic Refinery Distillation Capacity[16]	17.4	17.6	17.9	16.8	16.8	16.9	17.3	-0.1%
Capacity Utilization Rate (percent)[17]	89.0	85.0	83.7	89.0	89.5	89.6	88.3	0.1%
Net Import Share of Product Supplied (percent)	58.5	57.3	50.5	47.6	47.1	46.4	45.4	-0.9%
Net Expenditures for Imported Crude Oil and Petroleum Products (billion 2008 dollars)	287.15	437.90	301.44	329.52	356.35	383.33	420.54	-0.1%

[1]Includes lease condensate.
[2]Strategic petroleum reserve stock additions plus unaccounted for crude oil and crude stock withdrawals minus crude product supplied.
[3]Includes other hydrocarbons and alcohols.
[4]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 pyrolysis oils, biomass-derived Fischer-Tropsch liquids, and renewable feedstocks used for the production of green diesel and gasoline.
[6]Includes domestic sources of other blending components, other hydrocarbons, and ethers.
[7]Total crude supply plus natural gas plant liquids, other inputs, refinery processing gain, and net product imports.
[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 fuel oil and kerosene from petroleum and biomass feedstocks.
[12]Includes aviation gasoline, petrochemical feedstocks, lubricants, waxes, asphalt, road oil, still gas, special naphthas, petroleum coke, crude oil product supplied, methanol, 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]End-of-year operable capacity.
[17]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 2007 and 2008 are model results and may differ slightly from official EIA data reports.
Sources: 2007 and 2008 petroleum product supplied based on: Energy Information Administration (EIA), *Annual Energy Review 2008*, DOE/EIA-0384(2008) (Washington, DC, June 2009). Other 2007 data: EIA, *Petroleum Supply Annual 2007,* DOE/EIA-0340(2007)/1 (Washington, DC, July 2008). Other 2008 data: EIA, *Petroleum Supply Annual 2008,* DOE/EIA-0340(2008)/1 (Washington, DC, June 2009). **Projections:** EIA, AEO2010 National Energy Modeling System run AEO2010R.D111809A.

Table A12. Petroleum Product Prices
(2008 Cents per Gallon, Unless Otherwise Noted)

Sector and Fuel	Reference Case							Annual Growth 2008-2035 (percent)
	2007	2008	2015	2020	2025	2030	2035	
Crude Oil Prices (2008 dollars per barrel)								
Imported Low Sulfur Light Crude Oil[1]	73.93	99.57	94.52	108.28	115.09	123.50	133.22	1.1%
Imported Crude Oil[1]	68.69	92.61	86.88	98.14	104.49	111.49	121.37	1.0%
Delivered Sector Product Prices								
Residential								
Liquefied Petroleum Gases	224.4	251.5	240.2	259.6	270.4	281.2	297.0	0.6%
Distillate Fuel Oil	281.6	339.3	292.4	334.2	349.9	369.1	397.5	0.6%
Commercial								
Distillate Fuel Oil	241.5	296.8	258.0	297.7	313.2	332.3	360.3	0.7%
Residual Fuel Oil	125.6	232.4	196.5	231.5	247.6	262.5	282.0	0.7%
Residual Fuel Oil (2008 dollars per barrel)	52.75	97.61	82.52	97.22	104.01	110.25	118.45	0.7%
Industrial[2]								
Liquefied Petroleum Gases	188.2	207.4	192.7	213.0	223.9	234.7	250.6	0.7%
Distillate Fuel Oil	249.5	307.4	260.9	299.6	315.4	335.0	363.6	0.6%
Residual Fuel Oil	132.3	244.1	246.5	272.4	287.9	303.5	325.1	1.1%
Residual Fuel Oil (2008 dollars per barrel)	55.57	102.52	103.52	114.41	120.91	127.46	136.54	1.1%
Transportation								
Liquefied Petroleum Gases	203.8	256.5	238.9	258.2	268.8	279.2	294.6	0.5%
Ethanol (E85)[3]	260.2	255.5	242.4	255.7	273.8	290.7	305.8	0.7%
Ethanol Wholesale Price	217.2	244.6	198.9	205.7	188.6	199.8	211.5	-0.5%
Motor Gasoline[4]	290.6	326.7	306.9	333.8	349.3	368.0	391.1	0.7%
Jet Fuel[5]	212.9	306.5	257.0	292.8	309.4	330.9	357.5	0.6%
Diesel Fuel (distillate fuel oil)[6]	295.6	379.3	314.3	350.8	364.9	383.1	410.5	0.3%
Residual Fuel Oil	137.5	216.9	203.3	224.4	238.5	255.9	278.5	0.9%
Residual Fuel Oil (2008 dollars per barrel)	57.76	91.11	85.37	94.27	100.18	107.49	116.95	0.9%
Electric Power[7]								
Distillate Fuel Oil	218.5	268.6	240.8	280.8	296.1	315.0	342.6	0.9%
Residual Fuel Oil	135.3	218.0	232.4	257.8	273.9	292.6	316.1	1.4%
Residual Fuel Oil (2008 dollars per barrel)	56.83	91.57	97.61	108.26	115.04	122.90	132.75	1.4%
Refined Petroleum Product Prices[8]								
Liquefied Petroleum Gases	162.0	173.0	174.0	189.8	200.1	210.4	226.0	1.0%
Motor Gasoline[4]	289.1	324.0	306.9	333.8	349.3	368.0	391.1	0.7%
Jet Fuel[5]	212.9	306.5	257.0	292.8	309.4	330.9	357.5	0.6%
Distillate Fuel Oil	285.0	361.2	302.3	340.2	355.2	374.4	402.5	0.4%
Residual Fuel Oil	135.8	221.1	213.4	236.7	251.4	268.8	291.3	1.0%
Residual Fuel Oil (2008 dollars per barrel)	57.03	92.85	89.64	99.43	105.61	112.92	122.34	1.0%
Average	**254.3**	**304.7**	**279.6**	**307.5**	**322.9**	**341.7**	**366.2**	**0.7%**

Table A12. Petroleum Product Prices (Continued)
(Nominal Cents per Gallon, Unless Otherwise Noted)

Sector and Fuel	Reference Case							Annual Growth 2008-2035 (percent)
	2007	2008	2015	2020	2025	2030	2035	
Crude Oil Prices (nominal dollars per barrel)								
Imported Low Sulfur Light Crude Oil[1]	72.32	99.57	105.33	132.33	156.20	186.40	223.88	3.0%
Imported Crude Oil[1]	67.19	92.61	96.82	119.94	141.80	168.28	203.97	3.0%
Delivered Sector Product Prices								
Residential								
Liquefied Petroleum Gases	219.5	251.5	267.7	317.3	367.0	424.4	499.1	2.6%
Distillate Fuel Oil	275.4	339.3	325.8	408.4	474.9	557.0	667.9	2.5%
Commercial								
Distillate Fuel Oil	236.2	296.8	287.6	363.9	425.1	501.6	605.5	2.7%
Residual Fuel Oil	122.9	232.4	219.0	282.9	336.1	396.2	474.0	2.7%
Residual Fuel Oil (nominal dollars per barrel)	51.60	97.61	91.96	118.82	141.15	166.40	199.06	2.7%
Industrial[2]								
Liquefied Petroleum Gases	184.1	207.4	214.8	260.3	303.9	354.2	421.2	2.7%
Distillate Fuel Oil	244.1	307.4	290.7	366.2	428.0	505.6	611.0	2.6%
Residual Fuel Oil	129.4	244.1	274.7	332.9	390.7	458.0	546.4	3.0%
Residual Fuel Oil (nominal dollars per barrel)	54.36	102.52	115.36	139.83	164.09	192.38	229.47	3.0%
Transportation								
Liquefied Petroleum Gases	199.3	256.5	266.3	315.6	364.8	421.4	495.1	2.5%
Ethanol (E85)[3]	254.6	255.5	270.1	312.5	371.6	438.8	513.9	2.6%
Ethanol Wholesale Price	212.4	244.6	221.6	251.4	256.0	301.5	355.4	1.4%
Motor Gasoline[4]	284.2	326.7	342.1	408.0	474.0	555.5	657.3	2.6%
Jet Fuel[5]	208.2	306.5	286.4	357.9	419.9	499.4	600.8	2.5%
Diesel Fuel (distillate fuel oil)[6]	289.2	379.3	350.2	428.7	495.2	578.2	689.9	2.2%
Residual Fuel Oil	134.5	216.9	226.5	274.3	323.7	386.3	468.0	2.9%
Residual Fuel Oil (nominal dollars per barrel)	56.49	91.11	95.13	115.21	135.96	162.24	196.55	2.9%
Electric Power[7]								
Distillate Fuel Oil	213.7	268.6	268.4	343.2	401.9	475.4	575.8	2.9%
Residual Fuel Oil	132.4	218.0	259.0	315.0	371.7	441.6	531.2	3.4%
Residual Fuel Oil (nominal dollars per barrel)	55.59	91.57	108.78	132.31	156.12	185.49	223.09	3.4%
Refined Petroleum Product Prices[8]								
Liquefied Petroleum Gases	158.4	173.0	193.9	232.0	271.5	317.6	379.8	3.0%
Motor Gasoline[4]	282.8	324.0	342.0	407.9	474.0	555.4	657.2	2.7%
Jet Fuel[5]	208.2	306.5	286.4	357.9	419.9	499.4	600.8	2.5%
Distillate Fuel Oil	278.7	361.2	336.9	415.8	482.1	565.1	676.4	2.4%
Residual Fuel Oil	132.8	221.1	237.9	289.3	341.2	405.8	489.5	3.0%
Residual Fuel Oil (nominal dollars per barrel)	55.79	92.85	99.90	121.51	143.32	170.42	205.59	3.0%
Average	**248.7**	**304.7**	**311.5**	**375.8**	**438.2**	**515.7**	**615.4**	**2.6%**

[1]Weighted average price delivered to U.S. refiners.
[2]Includes energy for combined heat and power plants, except those whose primary business is to sell electricity, or electricity and heat, to the public.
[3]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 and 2008 are model results and may differ slightly from official EIA data reports.
Sources: 2007 and 2008 imported low sulfur light crude oil price: Energy Information Administration (EIA), Form EIA-856, "Monthly Foreign Crude Oil Acquisition Report." 2007 and 2008 imported crude oil price: EIA, *Annual Energy Review 2008*, DOE/EIA-0384(2008) (Washington, DC, June 2009). 2007 and 2008 prices for motor gasoline, distillate fuel oil, and jet fuel are based on: EIA, *Petroleum Marketing Annual 2008*, DOE/EIA-0487(2008) (Washington, DC, August 2009). 2007 and 2008 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 and 2008 electric power prices based on: Federal Energy Regulatory Commission, FERC Form 423, "Monthly Report of Cost and Quality of Fuels for Electric Plants." 2007 and 2008 E85 prices derived from monthly prices in the Clean Cities Alternative Fuel Price Report. 2007 and 2008 wholesale ethanol prices derived from Bloomberg U.S. average rack price. **Projections:** EIA, AEO2010 National Energy Modeling System run AEO2010R.D111809A.

Table A13. Natural Gas Supply, Disposition, and Prices
(Trillion Cubic Feet per Year, Unless Otherwise Noted)

Supply, Disposition, and Prices	Reference Case							Annual Growth 2008-2035 (percent)
	2007	2008	2015	2020	2025	2030	2035	
Production								
Dry Gas Production[1]	19.09	20.56	19.29	19.98	21.31	22.38	23.27	0.5%
Supplemental Natural Gas[2]	0.06	0.05	0.06	0.06	0.06	0.06	0.06	0.6%
Net Imports	**3.79**	**2.95**	**2.38**	**2.57**	**2.17**	**1.84**	**1.46**	**-2.6%**
Pipeline[3]	3.06	2.65	1.29	1.07	0.89	0.94	0.64	-5.1%
Liquefied Natural Gas	0.72	0.30	1.09	1.50	1.28	0.89	0.83	3.8%
Total Supply	**22.94**	**23.57**	**21.73**	**22.61**	**23.54**	**24.28**	**24.80**	**0.2%**
Consumption by Sector								
Residential	4.70	4.87	4.71	4.83	4.89	4.89	4.87	0.0%
Commercial	3.01	3.12	3.23	3.33	3.45	3.55	3.69	0.6%
Industrial[4]	6.62	6.65	6.88	7.03	6.94	6.74	6.72	0.0%
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]	6.84	6.66	5.18	5.66	6.28	7.04	7.42	0.4%
Transportation[8]	0.04	0.04	0.05	0.08	0.11	0.15	0.19	5.9%
Pipeline Fuel	0.62	0.63	0.60	0.62	0.70	0.72	0.72	0.5%
Lease and Plant Fuel[9]	1.18	1.28	1.08	1.09	1.19	1.23	1.25	-0.1%
Total	**23.02**	**23.25**	**21.74**	**22.63**	**23.57**	**24.33**	**24.86**	**0.2%**
Discrepancy[10]	**-0.08**	**0.32**	**-0.01**	**-0.02**	**-0.03**	**-0.05**	**-0.07**	**- -**
Natural Gas Prices								
(2008 dollars per million Btu)								
Henry Hub Spot Price	7.12	8.86	6.27	6.64	6.99	8.05	8.88	0.0%
Average Lower 48 Wellhead Price[11]	6.38	7.85	5.54	5.87	6.18	7.11	7.84	-0.0%
(2008 dollars per thousand cubic feet)								
Average Lower 48 Wellhead Price[11]	6.56	8.07	5.70	6.03	6.35	7.31	8.06	-0.0%
Delivered Prices								
(2008 dollars per thousand cubic feet)								
Residential	13.32	13.87	11.89	12.30	12.65	13.83	14.82	0.2%
Commercial	11.53	12.29	10.28	10.65	11.01	12.12	13.03	0.2%
Industrial[4]	7.80	9.38	6.63	6.89	7.22	8.21	8.99	-0.2%
Electric Power[7]	7.45	9.34	6.24	6.59	6.94	7.94	8.69	-0.3%
Transportation[12]	14.24	16.42	13.76	13.83	13.82	14.60	15.21	-0.3%
Average[13]	**9.45**	**10.83**	**8.37**	**8.68**	**9.00**	**10.01**	**10.83**	**0.0%**

Table A13. Natural Gas Supply, Disposition, and Prices (Continued)
(Trillion Cubic Feet per Year, Unless Otherwise Noted)

Supply, Disposition, and Prices	Reference Case 2007	2008	2015	2020	2025	2030	2035	Annual Growth 2008-2035 (percent)
Natural Gas Prices								
(nominal dollars per million Btu)								
Henry Hub Spot Price	6.96	8.86	6.99	8.11	9.49	12.15	14.92	1.9%
Average Lower 48 Wellhead Price[11]	6.24	7.85	6.17	7.17	8.38	10.73	13.18	1.9%
(nominal dollars per thousand cubic feet)								
Average Lower 48 Wellhead Price[11]	6.42	8.07	6.35	7.37	8.62	11.03	13.55	1.9%
Delivered Prices								
(nominal dollars per thousand cubic feet)								
Residential	13.03	13.87	13.25	15.03	17.16	20.88	24.90	2.2%
Commercial	11.28	12.29	11.46	13.02	14.95	18.30	21.89	2.2%
Industrial[4]	7.63	9.38	7.39	8.43	9.80	12.39	15.10	1.8%
Electric Power[7]	7.29	9.34	6.96	8.06	9.41	11.98	14.61	1.7%
Transportation[12]	13.93	16.42	15.33	16.90	18.76	22.04	25.56	1.7%
Average[13]	**9.24**	**10.83**	**9.33**	**10.61**	**12.21**	**15.11**	**18.20**	**1.9%**

[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, 2007 and 2008 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 2007 and 2008 are model results and may differ slightly from official EIA data reports.
Sources: 2007 supply values; and lease, plant, and pipeline fuel consumption: Energy Information Administration (EIA), *Natural Gas Annual 2007*, DOE/EIA-0131(2007) (Washington, DC, January 2009). 2008 supply values; and lease, plant, and pipeline fuel consumption; and wellhead price: EIA, *Natural Gas Monthly*, DOE/EIA-0130(2009/07) (Washington, DC, July 2009). Other 2007 and 2008 consumption based on: EIA, *Annual Energy Review 2008*, DOE/EIA-0384(2008) (Washington, DC, June 2009). 2007 wellhead price: Minerals Management Service and EIA, *Natural Gas Annual 2007*, DOE/EIA-0131(2007) (Washington, DC, January 2009). 2007 residential and commercial delivered prices: EIA, *Natural Gas Annual 2007*, DOE/EIA-0131(2007) (Washington, DC, January 2009). 2008 residential and commercial delivered prices: EIA, *Natural Gas Monthly*, DOE/EIA-0130(2009/07) (Washington, DC, July 2009). 2007 and 2008 electric power prices: EIA, *Electric Power Monthly*, DOE/EIA-0226, April 2008 and April 2009, Table 4.13.B. 2007 and 2008 industrial delivered prices are estimated based on: EIA, *Manufacturing Energy Consumption Survey* and industrial and wellhead prices from the *Natural Gas Annual 2007*, DOE/EIA-0131(2007) (Washington, DC, January 2009) and the *Natural Gas Monthly*, DOE/EIA-0130(2009/07) (Washington, DC, July 2009). 2007 transportation sector delivered prices are based on: EIA, *Natural Gas Annual 2007*, DOE/EIA-0131(2007) (Washington, DC, January 2009) and estimated state taxes, federal taxes, and dispensing costs or charges. 2008 transportation sector delivered prices are model results. **Projections:** EIA, AEO2010 National Energy Modeling System run AEO2010R.D111809A.

Table A14. Oil and Gas Supply

Production and Supply	Reference Case							Annual Growth 2008-2035 (percent)
	2007	2008	2015	2020	2025	2030	2035	
Crude Oil								
Lower 48 Average Wellhead Price[1]								
(2008 dollars per barrel)	**68.52**	**95.24**	**90.84**	**102.00**	**108.31**	**114.75**	**124.69**	**1.0%**
Production (million barrels per day)[2]								
United States Total	5.08	4.96	5.77	6.13	6.13	6.20	6.27	0.9%
Lower 48 Onshore	2.95	3.00	3.34	3.37	3.25	3.43	3.46	0.5%
Lower 48 Offshore	1.40	1.27	1.94	2.08	2.14	2.19	2.36	2.3%
Alaska	0.72	0.69	0.49	0.68	0.74	0.58	0.45	-1.6%
Lower 48 End of Year Reserves[2]								
(billion barrels)	**18.65**	**17.18**	**19.41**	**20.78**	**22.44**	**23.42**	**23.57**	**1.2%**
Natural Gas								
Lower 48 Average Wellhead Price[1]								
(2008 dollars per million Btu)								
Henry Hub Spot Price	7.12	8.86	6.27	6.64	6.99	8.05	8.88	0.0%
Average Lower 48 Wellhead Price[1]	6.38	7.85	5.54	5.87	6.18	7.11	7.84	-0.0%
(2008 dollars per thousand cubic feet)								
Average Lower 48 Wellhead Price[1]	6.56	8.07	5.70	6.03	6.35	7.31	8.06	-0.0%
Dry Production (trillion cubic feet)[3]								
United States Total	19.09	20.56	19.29	19.98	21.31	22.38	23.27	0.5%
Lower 48 Onshore	15.70	17.56	16.09	16.23	15.96	16.59	17.07	-0.1%
Associated-Dissolved[4]	1.31	1.39	1.44	1.42	1.25	1.12	1.03	-1.1%
Non-Associated	14.39	16.17	14.65	14.80	14.71	15.47	16.04	-0.0%
Conventional[5]	11.33	12.71	8.92	8.41	8.00	8.13	8.11	-1.7%
Unconventional	3.06	3.46	5.73	6.40	6.71	7.35	7.93	3.1%
Shale Gas	1.15	1.49	3.85	4.51	4.94	5.50	6.00	5.3%
Coalbed Methane	1.91	1.97	1.89	1.88	1.77	1.85	1.93	-0.1%
Lower 48 Offshore	2.98	2.62	2.91	3.48	3.46	3.91	4.33	1.9%
Associated-Dissolved[4]	0.62	0.55	0.79	0.93	0.90	0.95	1.00	2.2%
Non-Associated	2.36	2.06	2.12	2.55	2.56	2.96	3.33	1.8%
Alaska	0.41	0.38	0.29	0.27	1.88	1.88	1.87	6.1%
Lower 48 End of Year Dry Reserves[3]								
(trillion cubic feet)	**225.81**	**235.63**	**254.61**	**260.13**	**259.77**	**263.33**	**267.94**	**0.5%**
Supplemental Gas Supplies (trillion cubic feet)[6]	**0.06**	**0.05**	**0.06**	**0.06**	**0.06**	**0.06**	**0.06**	**0.6%**
Total Lower 48 Wells Drilled (thousands)	**50.94**	**55.72**	**54.40**	**56.08**	**56.68**	**59.04**	**60.93**	**0.3%**

[1]Represents lower 48 onshore and offshore supplies.
[2]Includes lease condensate.
[3]Marketed production (wet) minus extraction losses.
[4]Gas which occurs in crude oil reservoirs either as free gas (associated) or as gas in solution with crude oil (dissolved).
[5]Includes tight gas.
[6]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 2007 and 2008 are model results and may differ slightly from official EIA data reports.

Sources: 2007 and 2008 crude oil lower 48 average wellhead price: Energy Information Administration (EIA), *Petroleum Marketing Annual 2008*, DOE/EIA-0487(2008) (Washington, DC, August 2009). 2007 and 2008 lower 48 onshore, lower 48 offshore, and Alaska crude oil production: EIA, *Petroleum Supply Annual 2008,* DOE/EIA-0340(2008)/1 (Washington, DC, June 2009). 2007 U.S. crude oil and natural gas reserves: EIA, *U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves*, DOE/EIA-0216(2008) (Washington, DC, October 2009). 2007 Alaska and total natural gas production, and supplemental gas supplies: EIA, *Natural Gas Annual 2007*, DOE/EIA-0131(2007) (Washington, DC, January 2009). 2007 natural gas lower 48 average wellhead price: Minerals Management Service and EIA, *Natural Gas Annual 2007*, DOE/EIA-0131(2007) (Washington, DC, January 2009). 2008 natural gas lower 48 average wellhead price, Alaska and total natural gas production, and supplemental gas supplies: EIA, *Natural Gas Monthly*, DOE/EIA-0130(2009/07) (Washington, DC, July 2009). Other 2007 and 2008 values: EIA, Office of Integrated Analysis and Forecasting. **Projections:** EIA, AEO2010 National Energy Modeling System run AEO2010R.D111809A.

Table A15. Coal Supply, Disposition, and Prices
(Million Short Tons per Year, Unless Otherwise Noted)

Supply, Disposition, and Prices	Reference Case							Annual Growth 2008-2035 (percent)
	2007	2008	2015	2020	2025	2030	2035	
Production[1]								
Appalachia	378	391	317	305	291	278	277	-1.3%
Interior	147	147	184	198	199	197	208	1.3%
West	621	634	654	681	744	785	800	0.9%
East of the Mississippi	478	493	444	444	422	407	415	-0.6%
West of the Mississippi	668	678	710	740	813	854	870	0.9%
Total	**1147**	**1172**	**1155**	**1183**	**1234**	**1260**	**1285**	**0.3%**
Waste Coal Supplied[2]	**14**	**14**	**16**	**15**	**15**	**14**	**15**	**0.3%**
Net Imports								
Imports[3]	34	32	30	37	34	38	53	1.9%
Exports	59	82	60	53	48	36	33	-3.3%
Total	**-25**	**-49**	**-30**	**-15**	**-14**	**2**	**20**	**- -**
Total Supply[4]	**1136**	**1136**	**1141**	**1183**	**1235**	**1276**	**1320**	**0.6%**
Consumption by Sector								
Residential and Commercial	4	4	3	3	3	3	3	-0.2%
Coke Plants	23	22	20	20	19	17	14	-1.7%
Other Industrial[5]	57	55	53	53	53	52	51	-0.2%
Coal-to-Liquids Heat and Power	0	0	11	17	24	31	37	- -
Coal to Liquids Production	0	0	9	15	20	26	31	- -
Electric Power[6]	1045	1042	1044	1073	1116	1147	1183	0.5%
Total	**1128**	**1122**	**1141**	**1183**	**1235**	**1276**	**1319**	**0.6%**
Discrepancy and Stock Change[7]	**8**	**15**	**-0**	**0**	**0**	**0**	**0**	**- -**
Average Minemouth Price[8]								
(2008 dollars per short ton)	26.40	31.26	30.38	30.01	28.19	27.43	28.10	-0.4%
(2008 dollars per million Btu)	1.30	1.55	1.52	1.51	1.44	1.41	1.44	-0.3%
Delivered Prices (2008 dollars per short ton)[9]								
Coke Plants	97.09	118.09	132.98	139.25	137.06	133.66	132.10	0.4%
Other Industrial[5]	55.64	63.44	57.43	56.95	56.11	56.74	57.88	-0.3%
Coal to Liquids	- -	- -	20.14	20.37	21.22	20.91	22.34	- -
Electric Power								
(2008 dollars per short ton)	36.08	40.71	39.46	38.90	38.49	39.29	40.74	0.0%
(2008 dollars per million Btu)	1.80	2.05	2.01	1.98	1.99	2.03	2.09	0.1%
Average	**38.31**	**43.36**	**41.58**	**40.95**	**40.16**	**40.44**	**41.42**	**-0.2%**
Exports[10]	71.82	97.68	109.63	124.95	113.11	102.92	96.29	-0.1%

Table A15. Coal Supply, Disposition, and Prices (Continued)
(Million Short Tons per Year, Unless Otherwise Noted)

Supply, Disposition, and Prices	Reference Case							Annual Growth 2008-2035 (percent)
	2007	2008	2015	2020	2025	2030	2035	
Average Minemouth Price[8]								
(nominal dollars per short ton)	25.82	31.26	33.86	36.67	38.25	41.40	47.23	1.5%
(nominal dollars per million Btu)	1.27	1.55	1.69	1.84	1.95	2.13	2.43	1.7%
Delivered Prices (nominal dollars per short ton)[9]								
Coke Plants	94.97	118.09	148.19	170.18	186.00	201.73	221.99	2.4%
Other Industrial[5]	54.42	63.44	64.00	69.59	76.14	85.64	97.27	1.6%
Coal to Liquids	- -	- -	22.44	24.90	28.80	31.55	37.54	- -
Electric Power								
(nominal dollars per short ton)	35.29	40.71	43.97	47.55	52.24	59.30	68.46	1.9%
(nominal dollars per million Btu)	1.76	2.05	2.24	2.42	2.69	3.06	3.51	2.0%
Average	**37.47**	**43.36**	**46.34**	**50.05**	**54.50**	**61.03**	**69.60**	**1.8%**
Exports[10]	70.25	97.68	122.17	152.70	153.50	155.34	161.81	1.9%

[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]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 2007 and 2008 are model results and may differ slightly from official EIA data reports.
Sources: 2007 and 2008 data based on: Energy Information Administration (EIA), *Annual Coal Report 2008*, DOE/EIA-0584(2008) (Washington, DC, September 2009); EIA, *Quarterly Coal Report, October-December 2008*, DOE/EIA-0121(2008/4Q) (Washington, DC, March 2009); and EIA, AEO2010 National Energy Modeling System run AEO2010R.D111809A. **Projections:** EIA, AEO2010 National Energy Modeling System run AEO2010R.D111809A.

Table A16. Renewable Energy Generating Capacity and Generation
(Gigawatts, Unless Otherwise Noted)

Capacity and Generation	Reference Case							Annual Growth 2008-2035 (percent)
	2007	2008	2015	2020	2025	2030	2035	
Electric Power Sector[1]								
Net Summer Capacity								
Conventional Hydropower	76.51	76.51	77.03	77.03	77.34	77.34	77.52	0.0%
Geothermal[2]	2.35	2.44	3.24	3.24	3.27	3.53	3.82	1.7%
Municipal Waste[3]	3.42	3.43	4.75	4.75	4.75	4.75	4.75	1.2%
Wood and Other Biomass[4,5]	2.09	2.17	4.46	4.46	4.75	6.92	11.87	6.5%
Solar Thermal	0.53	0.53	0.87	0.89	0.91	0.93	0.96	2.2%
Solar Photovoltaic[6]	0.04	0.05	0.14	0.22	0.31	0.40	0.45	8.6%
Wind	16.19	24.89	63.98	64.05	65.42	66.08	68.88	3.8%
Offshore Wind	0.00	0.00	0.20	0.20	0.20	0.20	0.20	- -
Total	**101.14**	**110.01**	**154.68**	**154.84**	**156.95**	**160.15**	**168.45**	**1.6%**
Generation (billion kilowatthours)								
Conventional Hydropower	245.13	245.45	296.56	296.63	298.57	298.64	299.45	0.7%
Geothermal[2]	14.64	14.86	23.53	23.54	23.79	25.88	28.13	2.4%
Biogenic Municipal Waste[7]	13.88	14.49	24.95	24.95	24.95	24.95	24.95	2.0%
Wood and Other Biomass[5]	10.59	10.90	47.22	86.80	109.06	114.66	117.45	9.2%
Dedicated Plants	8.65	9.00	26.78	27.11	29.85	46.51	82.01	8.5%
Cofiring	1.94	1.90	20.44	59.69	79.21	68.15	35.43	11.4%
Solar Thermal	0.60	0.81	1.80	1.87	1.94	2.02	2.10	3.6%
Solar Photovoltaic[6]	0.01	0.03	0.34	0.54	0.76	0.98	1.13	14.2%
Wind	34.45	52.03	195.18	195.47	200.51	202.88	213.84	5.4%
Offshore Wind	0.00	0.00	0.75	0.75	0.75	0.75	0.75	- -
Total	**319.29**	**338.56**	**590.33**	**630.56**	**660.33**	**670.76**	**687.80**	**2.7%**
End-Use Generators[8]								
Net Summer Capacity								
Conventional Hydropower[9]	0.68	0.69	0.69	0.69	0.69	0.69	0.69	0.0%
Geothermal	0.00	0.00	0.00	0.00	0.00	0.00	0.00	- -
Municipal Waste[10]	0.33	0.33	0.33	0.33	0.33	0.33	0.33	0.0%
Biomass	4.88	4.86	6.31	9.04	16.04	22.07	24.51	6.2%
Solar Photovoltaic[6]	0.47	0.80	8.07	9.91	10.27	11.28	13.14	10.9%
Wind	0.08	0.09	1.52	1.92	2.01	2.11	2.29	12.5%
Total	**6.45**	**6.77**	**16.92**	**21.89**	**29.34**	**36.48**	**40.96**	**6.9%**
Generation (billion kilowatthours)								
Conventional Hydropower[9]	2.38	3.35	3.35	3.35	3.35	3.35	3.35	0.0%
Geothermal	0.00	0.00	0.00	0.00	0.00	0.00	0.00	- -
Municipal Waste[10]	2.01	2.02	2.79	2.79	2.79	2.79	2.79	1.2%
Biomass	28.43	27.89	37.25	57.37	109.23	153.77	172.75	7.0%
Solar Photovoltaic[6]	0.74	1.26	13.12	16.12	16.73	18.43	21.58	11.1%
Wind	0.10	0.12	2.10	2.66	2.79	2.94	3.19	12.9%
Total	**33.65**	**34.63**	**58.60**	**82.28**	**134.88**	**181.28**	**203.65**	**6.8%**

Table A16. Renewable Energy Generating Capacity and Generation (Continued)
(Gigawatts, Unless Otherwise Noted)

Capacity and Generation	Reference Case							Annual Growth 2008-2035 (percent)
	2007	2008	2015	2020	2025	2030	2035	
Total, All Sectors								
Net Summer Capacity								
Conventional Hydropower	77.20	77.19	77.72	77.72	78.03	78.03	78.21	0.0%
Geothermal	2.35	2.44	3.24	3.24	3.27	3.53	3.82	1.7%
Municipal Waste	3.75	3.77	5.08	5.08	5.08	5.08	5.08	1.1%
Wood and Other Biomass[4,5]	6.98	7.02	10.76	13.50	20.80	28.99	36.38	6.3%
Solar[6]	1.04	1.38	9.08	11.02	11.49	12.60	14.55	9.1%
Wind	16.27	24.98	65.71	66.17	67.63	68.39	71.36	4.0%
Total	**107.59**	**116.78**	**171.60**	**176.73**	**186.29**	**196.63**	**209.40**	**2.2%**
Generation (billion kilowatthours)								
Conventional Hydropower	247.51	248.79	299.91	299.98	301.92	301.99	302.80	0.7%
Geothermal	14.64	14.86	23.53	23.54	23.79	25.88	28.13	2.4%
Municipal Waste	15.89	16.51	27.74	27.74	27.74	27.74	27.74	1.9%
Wood and Other Biomass[5]	39.01	38.79	84.47	144.17	218.29	268.44	290.19	7.7%
Solar[6]	1.35	2.10	15.26	18.53	19.44	21.43	24.81	9.6%
Wind	34.55	52.15	198.03	198.88	204.05	206.57	217.78	5.4%
Total	**352.95**	**373.20**	**648.94**	**712.84**	**795.22**	**852.04**	**891.45**	**3.3%**

[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 2007, EIA estimates that as much as 221 megawatts of remote electricity generation PV applications (i.e., off-grid power systems) were in service in 2007, plus an additional 542 megawatts in communications, transportation, and assorted other non-grid-connected, specialized applications. See Energy Information Administration, *Annual Energy Review 2008*, DOE/EIA-0384(2008) (Washington, DC, June 2009), Table 10.9 (annual PV shipments, 1989-2007). 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 2007 and 2008 are model results and may differ slightly from official EIA data reports.
Sources: 2007 and 2008 capacity: Energy Information Administration (EIA), Form EIA-860, "Annual Electric Generator Report" (preliminary). 2007 and 2008 generation: EIA, *Annual Energy Review 2008*, DOE/EIA-0384(2008) (Washington, DC, June 2009). **Projections:** EIA, AEO2010 National Energy Modeling System run AEO2010R.D111809A.

Table A17. Renewable Energy, Consumption by Sector and Source[1]
(Quadrillion Btu per Year)

Sector and Source	Reference Case							Annual Growth 2008-2035 (percent)
	2007	2008	2015	2020	2025	2030	2035	
Marketed Renewable Energy[2]								
Residential (wood)	**0.41**	**0.45**	**0.40**	**0.42**	**0.42**	**0.42**	**0.43**	**-0.1%**
Commercial (biomass)	**0.10**	**0.10**	**0.10**	**0.10**	**0.10**	**0.10**	**0.10**	**0.0%**
Industrial[3]	**2.02**	**2.53**	**2.37**	**2.70**	**3.23**	**3.69**	**4.39**	**2.1%**
Conventional Hydroelectric	0.02	0.03	0.03	0.03	0.03	0.03	0.03	0.0%
Municipal Waste[4]	0.17	0.17	0.17	0.17	0.17	0.17	0.17	0.1%
Biomass	1.42	1.30	1.39	1.48	1.54	1.59	1.63	0.8%
Biofuels Heat and Coproducts[5]	0.40	1.03	0.77	1.02	1.49	1.90	2.56	3.4%
Transportation	**0.64**	**0.96**	**1.53**	**1.81**	**2.41**	**3.10**	**3.92**	**5.4%**
Ethanol used in E85[6]	0.00	0.00	0.01	0.17	0.34	0.54	1.15	23.3%
Ethanol used in Gasoline Blending	0.58	0.84	1.22	1.20	1.22	1.23	1.20	1.3%
Biodiesel used in Distillate Blending	0.06	0.09	0.21	0.23	0.22	0.25	0.25	3.9%
Liquids from Biomass	0.00	0.00	0.04	0.16	0.56	1.04	1.27	- -
Green Liquids	0.00	0.02	0.05	0.05	0.06	0.04	0.04	2.6%
Electric Power[7]	**3.45**	**3.65**	**6.27**	**6.69**	**7.00**	**7.13**	**7.26**	**2.6%**
Conventional Hydroelectric	2.42	2.43	2.93	2.93	2.95	2.95	2.96	0.7%
Geothermal	0.31	0.31	0.57	0.57	0.58	0.65	0.73	3.2%
Biogenic Municipal Waste[8]	0.17	0.17	0.31	0.31	0.31	0.31	0.31	2.3%
Biomass	0.21	0.22	0.50	0.91	1.14	1.18	1.11	6.1%
Dedicated Plants	0.14	0.14	0.30	0.31	0.33	0.47	0.74	6.3%
Cofiring	0.07	0.08	0.21	0.61	0.81	0.71	0.37	5.8%
Solar Thermal	0.01	0.01	0.02	0.02	0.02	0.02	0.02	3.6%
Solar Photovoltaic	0.00	0.00	0.00	0.01	0.01	0.01	0.01	14.2%
Wind	0.34	0.51	1.94	1.94	1.99	2.01	2.12	5.4%
Total Marketed Renewable Energy	**6.62**	**7.68**	**10.68**	**11.72**	**13.16**	**14.44**	**16.10**	**2.8%**
Sources of Ethanol								
From Corn	0.55	0.78	1.17	1.19	1.26	1.28	1.49	2.4%
From Cellulose	0.00	0.00	0.02	0.12	0.16	0.16	0.43	- -
Imports	0.03	0.06	0.05	0.07	0.14	0.32	0.43	7.4%
Total	**0.58**	**0.84**	**1.23**	**1.38**	**1.56**	**1.76**	**2.35**	**3.9%**

Table A17. Renewable Energy, Consumption by Sector and Source[1] (Continued)
(Quadrillion Btu per Year)

Sector and Source	Reference Case							Annual Growth 2008-2035 (percent)
	2007	2008	2015	2020	2025	2030	2035	
Nonmarketed Renewable Energy[9] Selected Consumption								
Residential	**0.01**	**0.01**	**0.07**	**0.09**	**0.09**	**0.10**	**0.11**	**10.4%**
Solar Hot Water Heating	0.00	0.00	0.00	0.00	0.00	0.01	0.01	2.1%
Geothermal Heat Pumps	0.00	0.00	0.02	0.03	0.03	0.04	0.04	9.5%
Solar Photovoltaic	0.00	0.00	0.04	0.05	0.05	0.05	0.05	19.0%
Wind	0.00	0.00	0.01	0.01	0.01	0.01	0.01	19.2%
Commercial	**0.03**	**0.03**	**0.04**	**0.04**	**0.04**	**0.05**	**0.05**	**2.3%**
Solar Thermal	0.02	0.02	0.03	0.03	0.03	0.03	0.03	0.7%
Solar Photovoltaic	0.00	0.00	0.01	0.01	0.01	0.01	0.02	6.4%
Wind	0.00	0.00	0.00	0.00	0.00	0.00	0.00	8.3%

[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 9,884 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]The energy content of biofuels feedstock minus the energy content of liquid fuel produced.
[6]Excludes motor gasoline component of E85.
[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]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).
[9]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 2007 and 2008 are model results and may differ slightly from official EIA data reports.
Sources: 2007 and 2008 ethanol: Energy Information Administration (EIA), *Annual Energy Review 2008*, DOE/EIA-0384(2008) (Washington, DC, June 2009). 2007 and 2008 electric power sector: EIA, Form EIA-860, "Annual Electric Generator Report" (preliminary). Other 2007 and 2008 values: EIA, Office of Integrated Analysis and Forecasting. **Projections:** EIA, AEO2010 National Energy Modeling System run AEO2010R.D111809A.

Table A18. Carbon Dioxide Emissions by Sector and Source
(Million Metric Tons, Unless Otherwise Noted)

Sector and Source	Reference Case							Annual Growth 2008-2035 (percent)
	2007	2008	2015	2020	2025	2030	2035	
Residential								
Petroleum	87	80	72	67	63	60	58	-1.2%
Natural Gas	257	265	257	263	267	267	266	0.0%
Coal	1	1	1	1	1	1	0	-1.2%
Electricity[1]	891	875	824	844	885	927	965	0.4%
Total	**1235**	**1220**	**1153**	**1175**	**1216**	**1255**	**1289**	**0.2%**
Commercial								
Petroleum	44	41	40	38	38	38	37	-0.4%
Natural Gas	164	170	176	182	188	194	201	0.6%
Coal	7	6	6	6	6	6	6	0.0%
Electricity[1]	856	858	862	903	961	1022	1086	0.9%
Total	**1071**	**1075**	**1085**	**1130**	**1194**	**1261**	**1331**	**0.8%**
Industrial[2]								
Petroleum	417	385	397	390	387	391	390	0.0%
Natural Gas[3]	404	409	420	429	430	423	423	0.1%
Coal	177	172	171	181	186	189	188	0.3%
Electricity[1]	658	623	586	591	582	576	574	-0.3%
Total	**1655**	**1589**	**1574**	**1590**	**1586**	**1578**	**1575**	**-0.0%**
Transportation								
Petroleum[4]	1985	1889	1879	1914	1970	2028	2065	0.3%
Natural Gas[5]	35	36	35	38	44	47	50	1.2%
Electricity[1]	4	4	4	5	6	8	9	3.0%
Total	**2025**	**1929**	**1918**	**1957**	**2021**	**2083**	**2125**	**0.4%**
Electric Power[6]								
Petroleum	55	40	35	36	37	37	38	-0.2%
Natural Gas	372	362	283	308	342	384	404	0.4%
Coal	1971	1946	1947	1987	2043	2100	2180	0.4%
Other[7]	12	12	12	12	12	12	12	0.0%
Total	**2409**	**2359**	**2277**	**2343**	**2434**	**2533**	**2634**	**0.4%**
Total by Fuel								
Petroleum[3]	2589	2436	2422	2445	2496	2554	2588	0.2%
Natural Gas	1232	1242	1171	1220	1272	1315	1345	0.3%
Coal	2155	2125	2125	2175	2236	2296	2376	0.4%
Other[7]	12	12	12	12	12	12	12	0.0%
Total	**5986**	**5814**	**5731**	**5851**	**6016**	**6176**	**6320**	**0.3%**
Carbon Dioxide Emissions (tons per person)	**19.8**	**19.0**	**17.5**	**17.1**	**16.8**	**16.5**	**16.2**	**-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 2008, international bunker fuels accounted for 86 to 130 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 2007 and 2008 are model results and may differ slightly from official EIA data reports.
Sources: 2007 and 2008 emissions and emission factors: Energy Information Administration (EIA), *Emissions of Greenhouse Gases in the United States 2008,* DOE/EIA-0573(2008) (Washington, DC, December 2009). **Projections:** EIA, AEO2010 National Energy Modeling System run AEO2010R.D111809A.

Table A19. Energy-Related Carbon Dioxide Emissions by End Use
(Million Metric Tons)

Sector and Source	Reference Case							Annual Growth 2008-2035 (percent)
	2007	2008	2015	2020	2025	2030	2035	
Residential								
Space Heating	282.53	289.92	267.63	266.98	265.74	262.58	259.98	-0.4%
Space Cooling	170.72	144.00	143.47	146.33	152.90	159.15	164.77	0.5%
Water Heating	165.45	164.53	163.75	168.19	171.03	169.05	164.76	0.0%
Refrigeration	71.48	69.90	62.10	62.69	64.97	68.33	71.63	0.1%
Cooking	32.94	33.04	33.42	34.70	36.00	37.42	38.75	0.6%
Clothes Dryers	53.45	52.99	50.92	51.42	53.25	55.63	57.68	0.3%
Freezers	15.15	14.86	13.63	13.90	14.43	15.01	15.59	0.2%
Lighting	136.32	134.71	97.95	89.78	86.20	85.58	86.49	-1.6%
Clothes Washers[1]	6.47	6.31	5.16	4.55	4.50	4.70	4.89	-0.9%
Dishwashers[1]	17.51	17.21	15.78	16.18	17.30	18.50	19.64	0.5%
Color Televisions and Set-Top Boxes	60.76	64.14	67.57	69.81	73.77	78.24	82.98	1.0%
Personal Computers and Related Equipment	28.48	31.17	32.95	32.35	32.54	34.37	35.28	0.5%
Furnace Fans and Boiler Circulation Pumps	24.13	25.62	25.89	27.45	29.76	30.87	31.66	0.8%
Other Uses	169.99	174.12	173.01	190.90	213.54	235.34	255.39	1.4%
Discrepancy[2]	0.10	-2.18	0.00	-0.00	0.00	-0.00	0.00	- -
Total Residential	**1235.49**	**1220.34**	**1153.24**	**1175.21**	**1215.92**	**1254.76**	**1289.49**	**0.2%**
Commercial								
Space Heating[3]	119.84	125.84	121.41	121.42	121.61	120.35	118.90	-0.2%
Space Cooling[3]	105.04	94.70	96.71	99.04	103.14	107.54	112.17	0.6%
Water Heating[3]	42.73	42.01	42.97	44.75	46.76	47.98	49.01	0.6%
Ventilation	91.87	91.92	95.19	99.08	104.51	109.07	112.97	0.8%
Cooking	13.12	13.12	13.82	14.39	15.11	15.67	16.21	0.8%
Lighting	198.68	193.19	178.58	181.18	187.41	193.09	198.73	0.1%
Refrigeration	75.22	75.18	61.97	59.05	59.64	61.46	64.10	-0.6%
Office Equipment (PC)	40.01	41.96	41.43	40.61	40.81	42.38	43.03	0.1%
Office Equipment (non-PC)	40.90	44.17	54.90	62.10	67.50	72.73	76.91	2.1%
Other Uses[4]	343.32	353.26	377.86	408.02	447.10	490.32	538.70	1.6%
Total Commercial	**1070.73**	**1075.35**	**1084.84**	**1129.64**	**1193.59**	**1260.59**	**1330.73**	**0.8%**
Industrial								
Manufacturing								
Refining	252.93	266.30	287.20	295.60	310.27	324.85	341.97	0.9%
Food Products	100.43	100.19	101.47	106.04	111.96	117.46	123.83	0.8%
Paper Products	93.07	88.60	80.84	80.66	80.11	79.37	79.15	-0.4%
Bulk Chemicals	321.82	294.24	285.03	279.21	268.46	255.48	241.94	-0.7%
Glass	17.20	17.33	16.59	18.45	19.38	20.04	19.85	0.5%
Cement Manufacturing	41.63	38.73	36.68	38.40	38.33	37.77	35.74	-0.3%
Iron and Steel	140.11	126.80	113.79	122.17	115.24	101.27	80.51	-1.7%
Aluminum	43.56	42.47	40.33	38.33	35.67	32.69	29.63	-1.3%
Fabricated Metal Products	44.84	43.35	40.36	40.19	38.63	36.81	34.90	-0.8%
Machinery	22.56	21.59	21.82	22.48	22.11	21.79	21.01	-0.1%
Computers and Electronics	24.90	23.78	28.34	31.59	31.44	31.11	32.81	1.2%
Transportation Equipment	45.37	41.17	45.61	42.50	41.93	44.66	49.17	0.7%
Electrical Equipment	17.76	17.28	15.95	16.59	16.88	17.40	17.88	0.1%
Wood Products	17.37	16.29	18.70	18.27	17.08	16.24	15.99	-0.1%
Plastics	42.78	40.47	39.58	40.16	41.45	42.79	44.24	0.3%
Balance of Manufacturing	172.70	162.15	145.06	146.22	144.04	143.54	146.95	-0.4%
Total Manufacturing	1399.03	1340.74	1317.36	1336.84	1333.00	1323.26	1315.57	-0.1%
Nonmanufacturing								
Agriculture	85.24	88.58	83.41	82.05	82.07	82.66	84.24	-0.2%
Mining	74.41	68.80	74.07	74.84	72.04	70.60	69.96	0.1%
Construction	82.70	81.80	74.71	72.45	70.91	69.66	69.22	-0.6%
Total Nonmanufacturing	242.34	239.17	232.19	229.34	225.02	222.92	223.42	-0.3%
Discrepancy[2]	14.11	9.36	24.74	23.72	27.60	31.73	36.48	- -
Total Industrial	**1655.48**	**1589.27**	**1574.29**	**1589.91**	**1585.62**	**1577.91**	**1575.47**	**-0.0%**

Table A19. Energy-Related Carbon Dioxide Emissions by End Use (Continued)
(Million Metric Tons)

Sector and Source	Reference Case							Annual Growth 2008-2035 (percent)
	2007	2008	2015	2020	2025	2030	2035	
Transportation								
Light-Duty Vehicles	1150.40	1098.07	1070.56	1061.28	1081.68	1101.06	1097.22	-0.0%
Commercial Light Trucks[5]	45.87	42.64	43.46	44.64	45.31	46.61	48.17	0.5%
Bus Transportation	18.70	18.05	19.03	19.96	20.91	21.78	22.69	0.9%
Freight Trucks	361.62	338.57	346.46	369.91	392.68	421.14	454.26	1.1%
Rail, Passenger	5.83	5.84	5.96	6.33	6.70	7.08	7.45	0.9%
Rail, Freight	43.83	41.62	42.23	44.92	46.97	48.41	49.82	0.7%
Shipping, Domestic	22.22	21.78	21.61	22.49	23.21	23.83	24.46	0.4%
Shipping, International	75.26	70.49	70.83	71.35	71.84	72.30	72.76	0.1%
Recreational Boats	17.66	17.00	17.39	17.99	18.62	19.19	19.70	0.5%
Air	194.85	187.28	197.09	211.87	221.07	227.35	232.61	0.8%
Military Use	50.57	50.30	46.94	47.90	49.00	50.03	51.05	0.1%
Lubricants	5.65	5.20	5.30	5.41	5.49	5.60	5.70	0.3%
Pipeline Fuel	33.97	34.21	32.57	33.65	38.05	39.09	39.52	0.5%
Discrepancy[2]	-1.77	-1.64	-1.06	-0.99	-0.90	-0.81	-0.73	- -
Total Transportation	**2024.67**	**1929.42**	**1918.35**	**1956.71**	**2020.64**	**2082.65**	**2124.70**	**0.4%**

[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 2007 and 2008 are model results and may differ slightly from official EIA data reports.
Sources: 2007 and 2008 emissions and emission factors: Energy Information Administration (EIA), *Emissions of Greenhouse Gases in the United States 2008,* DOE/EIA-0573(2008) (Washington, DC, December 2009). **Projections:** EIA, AEO2010 National Energy Modeling System run AEO2010R.D111809A.

Table A20. Macroeconomic Indicators
(Billion 2000 Chain-Weighted Dollars, Unless Otherwise Noted)

Indicators	Reference Case							Annual Growth 2008-2035 (percent)
	2007	2008	2015	2020	2025	2030	2035	
Real Gross Domestic Product	**11524**	**11652**	**13289**	**15416**	**17561**	**19883**	**22362**	**2.4%**
Components of Real Gross Domestic Product								
Real Consumption	8253	8272	9343	10776	12348	14082	15932	2.5%
Real Investment	1810	1689	2178	2600	2988	3486	4104	3.3%
Real Government Spending	2012	2070	2085	2202	2319	2446	2569	0.8%
Real Exports	1426	1514	2000	2839	3773	4882	6211	5.4%
Real Imports	1972	1904	2240	2822	3574	4591	5881	4.3%
Energy Intensity (thousand Btu per 2000 dollar of GDP)								
Delivered Energy	6.41	6.23	5.52	4.89	4.43	4.02	3.68	-1.9%
Total Energy	8.82	8.59	7.65	6.81	6.16	5.59	5.12	-1.9%
Price Indices								
GDP Chain-type Price Index (2000=1.000)	1.198	1.225	1.365	1.497	1.662	1.849	2.059	1.9%
Consumer Price Index (1982-4=1.00)								
All-urban	2.07	2.15	2.43	2.72	3.07	3.46	3.92	2.2%
Energy Commodities and Services	2.08	2.36	2.41	2.81	3.23	3.79	4.46	2.4%
Wholesale Price Index (1982=1.00)								
All Commodities	1.73	1.90	1.93	2.09	2.24	2.42	2.62	1.2%
Fuel and Power	1.78	2.14	2.04	2.38	2.76	3.29	3.92	2.3%
Metals and Metal Products	1.93	2.13	2.19	2.30	2.36	2.41	2.45	0.5%
Interest Rates (percent, nominal)								
Federal Funds Rate	5.02	1.93	4.72	5.10	5.07	5.19	5.19	- -
10-Year Treasury Note	4.63	3.67	5.44	5.74	5.84	5.90	5.89	- -
AA Utility Bond Rate	5.94	6.19	7.22	7.59	7.79	8.05	8.30	- -
Value of Shipments (billion 2000 dollars)								
Service Sectors	19128	18812	20956	23808	27205	31356	36289	2.5%
Total Industrial	5652	5408	6044	6651	6997	7401	7786	1.4%
Nonmanufacturing	1436	1394	1547	1644	1673	1722	1776	0.9%
Manufacturing	4215	4014	4497	5006	5324	5680	6010	1.5%
Energy-Intensive	1238	1230	1315	1406	1467	1515	1542	0.8%
Non-energy Intensive	2977	2784	3182	3600	3856	4164	4468	1.8%
Total Shipments	**24779**	**24220**	**27001**	**30458**	**34202**	**38757**	**44074**	**2.2%**
Population and Employment (millions)								
Population, with Armed Forces Overseas	302.4	305.4	326.7	342.6	358.6	374.7	390.7	0.9%
Population, aged 16 and over	237.2	240.0	257.4	270.3	283.6	297.2	310.7	1.0%
Population, over age 65	38.0	38.8	47.0	55.0	64.2	72.3	77.7	2.6%
Employment, Nonfarm	137.5	137.0	142.5	151.0	157.4	165.2	171.4	0.8%
Employment, Manufacturing	13.9	13.4	12.2	12.1	11.3	11.4	12.8	-0.2%
Key Labor Indicators								
Labor Force (millions)	153.1	154.3	161.4	167.2	171.4	176.6	183.4	0.6%
Nonfarm Labor Productivity (1992=1.00)	1.37	1.41	1.57	1.75	1.96	2.17	2.39	2.0%
Unemployment Rate (percent)	4.63	5.81	7.32	5.28	5.31	5.36	5.49	- -
Key Indicators for Energy Demand								
Real Disposable Personal Income	8644	8753	10091	11967	13974	16069	18168	2.7%
Housing Starts (millions)	1.44	0.98	1.88	2.03	1.89	1.78	1.70	2.0%
Commercial Floorspace (billion square feet)	77.3	78.8	85.1	91.1	97.5	103.9	110.5	1.3%
Unit Sales of Light-Duty Vehicles (millions)	16.09	13.13	17.25	17.43	17.92	19.00	20.09	1.6%

GDP = Gross domestic product.
Btu = British thermal unit.
- - = Not applicable.
Sources: 2007 and 2008: IHS Global Insight Industry and Employment models, August 2009. **Projections:** Energy Information Administration, AEO2010 National Energy Modeling System run AEO2010R.D111809A.

Table A21. International Liquids Supply and Disposition Summary
(Million Barrels per Day, Unless Otherwise Noted)

Supply and Disposition	Reference Case							Annual Growth 2008-2035 (percent)
	2007	2008	2015	2020	2025	2030	2035	
Crude Oil Prices (2008 dollars per barrel)[1]								
Imported Low Sulfur Light Crude Oil	73.93	99.57	94.52	108.28	115.09	123.50	133.22	1.1%
Imported Crude Oil	68.69	92.61	86.88	98.14	104.49	111.49	121.37	1.0%
Crude Oil Prices (nominal dollars per barrel)[1]								
Imported Low Sulfur Light Crude Oil	72.32	99.57	105.33	132.33	156.20	186.40	223.88	3.0%
Imported Crude Oil	67.19	92.61	96.82	119.94	141.80	168.28	203.97	3.0%
Conventional Production (Conventional)[2]								
OPEC[3]								
Middle East	23.06	24.24	25.42	26.57	27.87	29.50	30.94	0.9%
North Africa	4.02	4.06	4.42	4.31	4.32	4.33	4.53	0.4%
West Africa	4.12	4.18	5.30	5.65	5.87	6.09	6.43	1.6%
South America	2.58	2.50	2.14	2.37	2.60	2.63	2.75	0.4%
Total OPEC	**33.78**	**34.98**	**37.28**	**38.90**	**40.65**	**42.56**	**44.64**	**0.9%**
Non-OPEC								
OECD								
United States (50 states)	8.14	7.68	8.83	9.37	9.32	9.34	9.14	0.6%
Canada	2.05	1.84	1.52	1.23	1.10	1.01	1.02	-2.2%
Mexico	3.50	3.19	2.12	1.76	1.88	2.08	2.21	-1.3%
OECD Europe[4]	5.23	4.96	3.66	3.11	2.95	2.88	2.96	-1.9%
Japan	0.13	0.13	0.14	0.15	0.16	0.17	0.17	1.0%
Australia and New Zealand	0.63	0.65	0.57	0.55	0.54	0.55	0.57	-0.5%
Total OECD	**19.69**	**18.46**	**16.83**	**16.18**	**15.96**	**16.04**	**16.08**	**-0.5%**
Non-OECD								
Russia	9.87	9.79	9.71	10.92	11.63	12.03	12.68	1.0%
Other Europe and Eurasia[5]	2.88	2.88	4.22	4.42	4.63	4.98	5.27	2.3%
China	3.91	3.97	3.62	3.46	3.27	3.15	3.27	-0.7%
Other Asia[6]	3.75	3.76	3.66	3.62	3.56	3.38	3.49	-0.3%
Middle East	1.52	1.54	1.63	1.36	1.30	1.26	1.31	-0.6%
Africa	2.41	2.39	2.49	2.52	2.63	2.70	2.84	0.6%
Brazil	1.94	1.95	3.08	3.93	4.44	4.88	5.18	3.7%
Other Central and South America	1.79	1.82	1.68	1.65	1.82	2.11	2.28	0.8%
Total Non-OECD	**28.08**	**28.09**	**30.09**	**31.88**	**33.28**	**34.50**	**36.32**	**1.0%**
Total Conventional Production	**81.55**	**81.53**	**84.21**	**86.96**	**89.89**	**93.09**	**97.05**	**0.6%**
Unconventional Production[7]								
United States (50 states)	0.46	0.66	1.14	1.34	1.72	2.11	2.86	5.6%
Other North America	1.39	1.53	2.88	3.49	4.10	4.57	4.84	4.4%
OECD Europe[4]	0.16	0.25	0.40	0.48	0.56	0.61	0.64	3.6%
Middle East	0.00	0.00	0.10	0.20	0.21	0.22	0.23	15.2%
Africa.	0.22	0.23	0.35	0.49	0.57	0.65	0.70	4.3%
Central and South America	0.94	1.09	1.48	1.95	2.41	2.81	3.10	3.9%
Other	0.28	0.23	0.36	0.67	1.23	1.82	2.28	8.9%
Total Unconventional Production	**3.46**	**3.98**	**6.71**	**8.61**	**10.79**	**12.79**	**14.65**	**4.9%**
Total Production	**85.01**	**85.51**	**90.92**	**95.57**	**100.68**	**105.88**	**111.69**	**1.0%**

Table A21. International Liquids Supply and Disposition Summary (Continued)
(Million Barrels per Day, Unless Otherwise Noted)

Supply and Disposition	Reference Case							Annual Growth 2008-2035 (percent)
	2007	2008	2015	2020	2025	2030	2035	
Consumption[8]								
OECD								
United States (50 states)	20.65	19.53	20.18	20.56	20.99	21.48	22.06	0.5%
United States Territories	0.39	0.40	0.49	0.53	0.57	0.62	0.62	1.6%
Canada	2.40	2.40	2.34	2.37	2.45	2.55	2.65	0.4%
Mexico	1.62	1.61	1.65	1.81	1.88	1.95	2.02	0.8%
OECD Europe[3]	15.30	15.30	14.36	14.57	14.58	14.58	14.59	-0.2%
Japan	5.00	4.90	4.88	4.99	4.85	4.72	4.59	-0.2%
South Korea	2.83	2.83	2.75	2.59	2.63	2.65	2.67	-0.2%
Australia and New Zealand	1.05	1.05	1.10	1.18	1.24	1.30	1.37	1.0%
Total OECD	**49.24**	**48.03**	**47.75**	**48.60**	**49.20**	**49.84**	**50.55**	**0.2%**
Non-OECD								
Russia	2.66	2.71	2.70	2.72	2.70	2.67	2.64	-0.1%
Other Europe and Eurasia[5]	2.34	2.39	2.34	2.32	2.41	2.50	2.59	0.3%
China	7.60	8.00	10.42	12.36	14.21	15.77	17.50	2.9%
India	2.33	2.37	3.06	3.80	4.18	4.57	5.00	2.8%
Other Asia[6]	6.68	6.73	7.19	7.66	8.50	9.40	10.40	1.6%
Middle East	6.30	6.61	7.62	8.18	9.01	10.06	11.23	2.0%
Africa	3.09	3.24	3.53	3.57	3.70	3.79	3.89	0.7%
Brazil	2.27	2.38	2.86	3.11	3.49	3.94	4.45	2.3%
Other Central and South America	3.44	3.57	3.45	3.25	3.28	3.34	3.44	-0.1%
Total Non-OECD	**36.71**	**38.00**	**43.17**	**46.97**	**51.48**	**56.04**	**61.14**	**1.8%**
Total Consumption	**85.95**	**86.03**	**90.92**	**95.57**	**100.68**	**105.88**	**111.69**	**1.0%**
OPEC Production[9]	34.39	35.63	38.11	39.97	41.91	44.04	46.26	1.0%
Non-OPEC Production[9]	50.62	49.88	52.80	55.60	58.77	61.84	65.43	1.0%
Net Eurasia Exports	9.70	9.52	11.96	14.23	15.58	16.72	17.90	2.4%
OPEC Market Share (percent)	40.5	41.7	41.9	41.8	41.6	41.6	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 2007 and 2008 are model results and may differ slightly from official EIA data reports.
Sources: 2007 and 2008 low sulfur light crude oil price: Energy Information Administration (EIA), Form EIA-856, “Monthly Foreign Crude Oil Acquisition Report.” 2007 and 2008 imported crude oil price: EIA, *Annual Energy Review 2008*, DOE/EIA-0384(2008) (Washington, DC, June 2009). 2007 quantities derived from: EIA, *International Energy Annual 2007*, DOE/EIA-0219(2007) (Washington, DC, August 2009). **2008 quantities and projections:** EIA, AEO2010 National Energy Modeling System run AEO2010R.D111809A and EIA, Generate World Oil Balance Model.

Economic Growth Case Comparisons

Table B1. Total Energy Supply, Disposition, and Price Summary
(Quadrillion Btu per Year, Unless Otherwise Noted)

Supply, Disposition, and Prices	2008	Projections								
		2015			2025			2035		
		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	10.51	12.40	12.41	12.42	12.83	13.22	13.39	13.51	13.50	13.69
Natural Gas Plant Liquids	2.57	2.27	2.27	2.30	2.26	2.24	2.37	2.22	2.37	2.48
Dry Natural Gas	21.14	19.68	19.83	20.12	20.32	21.90	23.17	22.28	23.92	25.26
Coal[1]	23.86	22.96	23.31	23.60	22.81	24.36	25.17	23.54	25.19	27.08
Nuclear Power	8.46	8.75	8.75	8.75	9.29	9.29	9.35	9.26	9.41	9.98
Hydropower	2.46	2.94	2.96	3.00	2.97	2.98	3.00	2.97	2.99	3.03
Biomass[2]	3.97	4.49	4.60	4.81	5.98	6.90	7.11	7.35	9.27	11.30
Other Renewable Energy[3]	1.17	2.33	3.01	4.12	2.45	3.07	4.24	2.57	3.36	4.65
Other[4]	0.10	0.65	0.73	0.80	0.86	0.94	1.04	0.73	0.81	1.05
Total	**74.23**	**76.46**	**77.88**	**79.93**	**79.79**	**84.91**	**88.84**	**84.43**	**90.83**	**98.51**
Imports										
Crude Oil	21.39	18.76	19.66	20.77	18.01	19.21	21.33	16.65	19.34	22.28
Liquid Fuels and Other Petroleum[5]	6.38	5.27	5.54	5.81	5.13	5.76	6.36	5.09	6.08	7.13
Natural Gas	4.06	3.50	3.59	3.66	3.86	3.94	4.29	3.08	3.49	4.07
Other Imports[6]	0.96	0.78	0.79	0.79	0.97	0.88	0.93	0.91	1.32	1.42
Total	**32.79**	**28.31**	**29.58**	**31.04**	**27.98**	**29.80**	**32.90**	**25.72**	**30.23**	**34.90**
Exports										
Petroleum[7]	3.71	3.48	3.53	3.59	3.79	3.91	4.07	3.93	4.12	4.37
Natural Gas	1.01	1.15	1.14	1.13	1.74	1.69	1.64	2.13	1.96	1.80
Coal	2.07	1.49	1.49	1.49	1.12	1.20	1.13	0.77	0.79	0.82
Total	**6.80**	**6.11**	**6.16**	**6.20**	**6.65**	**6.80**	**6.84**	**6.82**	**6.87**	**6.99**
Discrepancy[8]	**0.13**	**-0.29**	**-0.30**	**-0.28**	**-0.24**	**-0.35**	**-0.41**	**-0.29**	**-0.32**	**-0.30**
Consumption										
Liquid Fuels and Other Petroleum[9]	38.35	37.59	38.81	40.23	37.50	40.14	43.11	37.49	42.02	46.82
Natural Gas	23.91	22.10	22.35	22.73	22.52	24.24	25.91	23.33	25.56	27.66
Coal[10]	22.41	21.99	22.35	22.64	22.25	23.63	24.52	23.14	25.11	26.99
Nuclear Power	8.46	8.75	8.75	8.75	9.29	9.29	9.35	9.26	9.41	9.98
Hydropower	2.46	2.94	2.96	3.00	2.97	2.98	3.00	2.97	2.99	3.03
Biomass[11]	3.10	3.05	3.17	3.38	4.15	4.70	4.98	4.68	5.83	7.33
Other Renewable Energy[3]	1.17	2.33	3.01	4.12	2.45	3.07	4.24	2.57	3.36	4.65
Other[12]	0.24	0.20	0.20	0.20	0.21	0.21	0.22	0.18	0.22	0.26
Total	**100.09**	**98.94**	**101.61**	**105.04**	**101.35**	**108.26**	**115.32**	**103.62**	**114.51**	**126.72**
Prices (2008 dollars per unit)										
Petroleum (dollars per barrel)										
Imported Low Sulfur Light Crude Oil Price[13]	99.57	92.93	94.52	96.00	112.85	115.09	118.95	128.73	133.22	138.80
Imported Crude Oil Price[13]	92.61	85.06	86.88	88.52	100.92	104.49	109.41	116.42	121.37	127.98
Natural Gas (dollars per million Btu)										
Price at Henry Hub	8.86	5.99	6.27	6.48	6.86	6.99	7.83	7.50	8.88	9.73
Wellhead Price[14]	7.85	5.29	5.54	5.73	6.06	6.18	6.92	6.62	7.84	8.59
Natural Gas (dollars per thousand cubic feet)										
Wellhead Price[14]	8.07	5.44	5.70	5.89	6.23	6.35	7.11	6.81	8.06	8.83
Coal (dollars per ton)										
Minemouth Price[15]	31.26	29.96	30.38	30.59	27.54	28.19	28.57	27.06	28.10	29.56
Coal (dollars per million Btu)										
Minemouth Price[15]	1.55	1.50	1.52	1.53	1.40	1.44	1.46	1.39	1.44	1.52
Average Delivered Price[16]	2.16	2.08	2.11	2.12	2.04	2.07	2.11	2.06	2.13	2.21
Average Electricity Price (cents per kilowatthour)	9.8	8.6	8.9	9.1	9.0	9.3	9.8	9.3	10.2	10.9

Table B1. Total Energy Supply and Disposition Summary (Continued)
(Quadrillion Btu per Year, Unless Otherwise Noted)

Supply, Disposition, and Prices	2008	Projections								
		2015			2025			2035		
		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]	99.57	107.49	105.33	102.10	170.24	156.20	143.29	251.80	223.88	195.45
Imported Crude Oil Price[13]	92.61	98.39	96.82	94.14	152.23	141.80	131.80	227.71	203.97	180.22
Natural Gas (dollars per million Btu)										
Price at Henry Hub	8.86	6.93	6.99	6.89	10.34	9.49	9.44	14.66	14.92	13.69
Wellhead Price[14]	7.85	6.12	6.17	6.09	9.14	8.38	8.34	12.95	13.18	12.10
Natural Gas (dollars per thousand cubic feet)										
Wellhead Price[14]	8.07	6.29	6.35	6.26	9.40	8.62	8.57	13.31	13.55	12.43
Coal (dollars per ton)										
Minemouth Price[15]	31.26	34.66	33.86	32.54	41.55	38.25	34.41	52.93	47.23	41.63
Coal (dollars per million Btu)										
Minemouth Price[15]	1.55	1.73	1.69	1.63	2.12	1.95	1.76	2.72	2.43	2.14
Average Delivered Price[16]	2.16	2.41	2.35	2.26	3.07	2.81	2.54	4.03	3.58	3.11
Average Electricity Price (cents per kilowatthour)	9.8	10.0	9.9	9.6	13.6	12.6	11.8	18.2	17.1	15.3

[1]Includes waste coal.
[2]Includes grid-connected electricity from wood and wood 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 and crude oil consumed as a fuel. Refer to Table A17 for detailed renewable liquid fuels consumption.
[10]Excludes coal converted to coal-based synthetic liquids and coal-based synthetic natural gas.
[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 2008 are model results and may differ slightly from official EIA data reports.
Sources: 2008 natural gas supply values and natural gas wellhead price: EIA, *Natural Gas Monthly*, DOE/EIA-0130(2009/07) (Washington, DC, July 2009). 2008 coal minemouth and delivered coal prices: EIA, *Annual Coal Report 2008*, DOE/EIA-0584(2008) (Washington, DC, September 2009). 2008 petroleum supply values: EIA, *Petroleum Supply Annual 2008,* DOE/EIA-0340(2008)/1 (Washington, DC, June 2009). 2008 low sulfur light crude oil price: EIA, Form EIA-856, "Monthly Foreign Crude Oil Acquisition Report." Other 2008 coal values: *Quarterly Coal Report, October-December 2008*, DOE/EIA-0121(2008/4Q) (Washington, DC, March 2009). Other 2008 values: EIA, *Annual Energy Review 2008*, DOE/EIA-0384(2008) (Washington, DC, June 2009). **Projections:** EIA, AEO2010 National Energy Modeling System runs LM2010.D011110A, AEO2010R.D111809A, and HM2010.D020310A.

Table B2. Energy Consumption by Sector and Source
(Quadrillion Btu per Year, Unless Otherwise Noted)

Sector and Source	2008	Projections								
		2015			2025			2035		
		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	0.45	0.41	0.41	0.41	0.39	0.40	0.41	0.38	0.40	0.42
Kerosene	0.04	0.04	0.04	0.04	0.03	0.03	0.04	0.03	0.03	0.03
Distillate Fuel Oil	0.68	0.59	0.59	0.59	0.48	0.49	0.49	0.41	0.41	0.42
Liquid Fuels and Other Petroleum Subtotal	1.18	1.03	1.04	1.04	0.91	0.92	0.93	0.82	0.85	0.87
Natural Gas	5.01	4.81	4.85	4.89	4.84	5.04	5.21	4.70	5.01	5.36
Coal	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Renewable Energy[1]	0.45	0.40	0.40	0.41	0.41	0.42	0.44	0.40	0.43	0.47
Electricity	4.71	4.73	4.78	4.83	5.07	5.30	5.52	5.38	5.83	6.29
Delivered Energy	**11.34**	**10.98**	**11.07**	**11.18**	**11.23**	**11.69**	**12.11**	**11.31**	**12.12**	**13.00**
Electricity Related Losses	10.20	10.09	10.24	10.53	10.65	11.08	11.58	11.13	11.79	12.70
Total	**21.54**	**21.06**	**21.31**	**21.70**	**21.88**	**22.76**	**23.69**	**22.44**	**23.92**	**25.69**
Commercial										
Liquefied Petroleum Gases	0.08	0.08	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09
Motor Gasoline[2]	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06
Kerosene	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Distillate Fuel Oil	0.36	0.31	0.31	0.30	0.28	0.28	0.28	0.26	0.26	0.26
Residual Fuel Oil	0.07	0.09	0.09	0.09	0.08	0.09	0.09	0.09	0.09	0.09
Liquid Fuels and Other Petroleum Subtotal	0.58	0.55	0.55	0.55	0.52	0.53	0.53	0.51	0.52	0.53
Natural Gas	3.21	3.30	3.32	3.35	3.44	3.55	3.62	3.67	3.79	3.97
Coal	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07
Renewable Energy[3]	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10
Electricity	4.61	4.94	5.00	5.08	5.53	5.76	5.99	6.20	6.55	6.96
Delivered Energy	**8.58**	**8.96**	**9.04**	**9.15**	**9.66**	**10.00**	**10.32**	**10.55**	**11.04**	**11.63**
Electricity Related Losses	10.00	10.54	10.72	11.06	11.61	12.03	12.58	12.83	13.27	14.05
Total	**18.58**	**19.50**	**19.77**	**20.21**	**21.28**	**22.03**	**22.91**	**23.38**	**24.30**	**25.69**
Industrial[4]										
Liquefied Petroleum Gases	2.14	2.23	2.31	2.41	2.20	2.55	2.87	1.88	2.35	2.87
Motor Gasoline[2]	0.30	0.28	0.30	0.33	0.27	0.30	0.34	0.25	0.30	0.35
Distillate Fuel Oil	1.19	1.12	1.19	1.27	1.05	1.17	1.30	1.00	1.17	1.33
Residual Fuel Oil	0.18	0.14	0.14	0.15	0.13	0.14	0.15	0.11	0.13	0.15
Petrochemical Feedstocks	1.12	0.99	1.09	1.20	0.73	0.82	0.96	0.68	0.81	0.96
Other Petroleum[5]	4.05	3.78	4.01	4.25	3.63	3.89	4.29	3.41	3.92	4.39
Liquid Fuels and Other Petroleum Subtotal	8.99	8.52	9.04	9.61	8.01	8.87	9.91	7.33	8.70	10.06
Natural Gas	6.84	6.82	7.08	7.40	6.43	7.14	7.79	6.02	6.91	7.97
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]	1.32	1.10	1.11	1.12	1.12	1.23	1.29	1.22	1.29	1.34
Natural Gas Subtotal	8.16	7.93	8.19	8.52	7.55	8.37	9.07	7.24	8.20	9.31
Metallurgical Coal	0.58	0.50	0.52	0.55	0.44	0.50	0.56	0.28	0.36	0.44
Other Industrial Coal	1.17	1.05	1.07	1.10	1.03	1.07	1.12	0.98	1.04	1.10
Coal-to-Liquids Heat and Power	0.00	0.16	0.16	0.16	0.33	0.34	0.36	0.52	0.55	0.59
Net Coal Coke Imports	0.04	0.01	0.01	0.01	0.00	0.01	0.02	-0.01	-0.00	0.01
Coal Subtotal	1.79	1.72	1.76	1.82	1.80	1.92	2.06	1.77	1.95	2.14
Biofuels Heat and Coproducts[7]	1.03	0.77	0.77	0.80	1.14	1.49	1.52	1.70	2.56	3.35
Renewable Energy[8]	1.50	1.52	1.59	1.68	1.58	1.74	1.92	1.54	1.83	2.13
Electricity	3.35	3.24	3.40	3.58	3.12	3.49	3.86	2.88	3.47	4.06
Delivered Energy	**24.81**	**23.70**	**24.76**	**26.00**	**23.20**	**25.88**	**28.34**	**22.46**	**26.70**	**31.05**
Electricity Related Losses	7.26	6.91	7.29	7.79	6.56	7.29	8.10	5.95	7.01	8.19
Total	**32.07**	**30.61**	**32.05**	**33.79**	**29.76**	**33.18**	**36.44**	**28.42**	**33.72**	**39.24**

Table B2. Energy Consumption by Sector and Source (Continued)
(Quadrillion Btu per Year, Unless Otherwise Noted)

Sector and Source	2008	Projections								
		2015			2025			2035		
		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	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.03	0.04
E85[9]	0.01	0.07	0.01	0.01	0.44	0.52	0.44	1.26	1.75	2.55
Motor Gasoline[2]	16.76	16.64	17.02	17.43	16.17	16.91	17.93	15.48	16.44	17.27
Jet Fuel[10]	3.15	3.18	3.26	3.34	3.44	3.62	3.82	3.46	3.80	4.17
Distillate Fuel Oil[11]	6.09	6.02	6.32	6.65	6.41	7.13	7.89	6.99	8.28	9.65
Residual Fuel Oil	0.93	0.94	0.94	0.94	0.95	0.96	0.97	0.96	0.97	0.99
Other Petroleum[12]	0.17	0.17	0.17	0.18	0.18	0.18	0.18	0.18	0.19	0.19
Liquid Fuels and Other Petroleum Subtotal	27.14	27.03	27.73	28.57	27.60	29.34	31.25	28.36	31.47	34.86
Pipeline Fuel Natural Gas	0.64	0.61	0.61	0.63	0.62	0.72	0.76	0.70	0.74	0.80
Compressed Natural Gas	0.04	0.05	0.05	0.06	0.10	0.11	0.12	0.17	0.19	0.23
Liquid Hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Electricity	0.02	0.02	0.03	0.03	0.03	0.04	0.05	0.05	0.06	0.07
Delivered Energy	**27.85**	**27.72**	**28.42**	**29.27**	**28.36**	**30.21**	**32.18**	**29.29**	**32.46**	**35.96**
Electricity Related Losses	0.05	0.05	0.05	0.06	0.07	0.08	0.10	0.10	0.11	0.14
Total	**27.90**	**27.77**	**28.48**	**29.33**	**28.43**	**30.29**	**32.28**	**29.39**	**32.58**	**36.10**
Delivered Energy Consumption for All Sectors										
Liquefied Petroleum Gases	2.70	2.73	2.82	2.93	2.70	3.06	3.40	2.37	2.87	3.43
E85[9]	0.01	0.07	0.01	0.01	0.44	0.52	0.44	1.26	1.75	2.55
Motor Gasoline[2]	17.12	16.98	17.38	17.81	16.50	17.28	18.32	15.80	16.80	17.68
Jet Fuel[10]	3.15	3.18	3.26	3.34	3.44	3.62	3.82	3.46	3.80	4.17
Kerosene	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06
Distillate Fuel Oil	8.33	8.03	8.40	8.81	8.22	9.07	9.96	8.66	10.13	11.66
Residual Fuel Oil	1.19	1.16	1.17	1.18	1.16	1.18	1.21	1.16	1.19	1.23
Petrochemical Feedstocks	1.12	0.99	1.09	1.20	0.73	0.82	0.96	0.68	0.81	0.96
Other Petroleum[13]	4.21	3.94	4.17	4.42	3.80	4.06	4.46	3.57	4.10	4.57
Liquid Fuels and Other Petroleum Subtotal	37.89	37.14	38.35	39.76	37.04	39.66	42.63	37.02	41.53	46.32
Natural Gas	15.10	14.99	15.31	15.70	14.82	15.84	16.74	14.56	15.91	17.52
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]	1.32	1.10	1.11	1.12	1.12	1.23	1.29	1.22	1.29	1.34
Pipeline Natural Gas	0.64	0.61	0.61	0.63	0.62	0.72	0.76	0.70	0.74	0.80
Natural Gas Subtotal	17.07	16.70	17.03	17.44	16.56	17.79	18.79	16.47	17.94	19.67
Metallurgical Coal	0.58	0.50	0.52	0.55	0.44	0.50	0.56	0.28	0.36	0.44
Other Coal	1.24	1.13	1.15	1.17	1.11	1.15	1.19	1.05	1.11	1.17
Coal-to-Liquids Heat and Power	0.00	0.16	0.16	0.16	0.33	0.34	0.36	0.52	0.55	0.59
Net Coal Coke Imports	0.04	0.01	0.01	0.01	0.00	0.01	0.02	-0.01	-0.00	0.01
Coal Subtotal	1.86	1.79	1.84	1.89	1.88	2.00	2.13	1.84	2.02	2.21
Biofuels Heat and Coproducts[7]	1.03	0.77	0.77	0.80	1.14	1.49	1.52	1.70	2.56	3.35
Renewable Energy[14]	2.05	2.02	2.10	2.19	2.09	2.27	2.46	2.05	2.37	2.70
Liquid Hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Electricity	12.69	12.93	13.20	13.51	13.75	14.58	15.42	14.52	15.90	17.38
Delivered Energy	**72.59**	**71.36**	**73.30**	**75.60**	**72.46**	**77.78**	**82.95**	**73.61**	**82.33**	**91.64**
Electricity Related Losses	27.50	27.59	28.31	29.44	28.89	30.48	32.37	30.01	32.19	35.08
Total	**100.09**	**98.94**	**101.61**	**105.04**	**101.35**	**108.26**	**115.32**	**103.62**	**114.51**	**126.72**
Electric Power[15]										
Distillate Fuel Oil	0.10	0.12	0.12	0.12	0.13	0.13	0.14	0.13	0.14	0.14
Residual Fuel Oil	0.36	0.33	0.33	0.34	0.34	0.34	0.35	0.34	0.35	0.37
Liquid Fuels and Other Petroleum Subtotal	0.47	0.45	0.46	0.46	0.47	0.48	0.49	0.48	0.49	0.51
Natural Gas	6.84	5.39	5.32	5.29	5.97	6.45	7.12	6.85	7.62	7.99
Steam Coal	20.55	20.20	20.51	20.75	20.38	21.63	22.39	21.29	23.09	24.78
Nuclear Power	8.46	8.75	8.75	8.75	9.29	9.29	9.35	9.26	9.41	9.98
Renewable Energy[16]	3.65	5.53	6.27	7.51	6.34	7.00	8.22	6.47	7.26	8.95
Electricity Imports	0.11	0.07	0.07	0.07	0.08	0.08	0.09	0.05	0.09	0.13
Total[17]	**40.20**	**40.52**	**41.51**	**42.95**	**42.65**	**45.06**	**47.78**	**44.53**	**48.09**	**52.46**

Table B2. Energy Consumption by Sector and Source (Continued)
(Quadrillion Btu per Year, Unless Otherwise Noted)

Sector and Source	2008	Projections								
		2015			2025			2035		
		Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth
Total Energy Consumption										
Liquefied Petroleum Gases	2.70	2.73	2.82	2.93	2.70	3.06	3.40	2.37	2.87	3.43
E85[9]	0.01	0.07	0.01	0.01	0.44	0.52	0.44	1.26	1.75	2.55
Motor Gasoline[2]	17.12	16.98	17.38	17.81	16.50	17.28	18.32	15.80	16.80	17.68
Jet Fuel[10]	3.15	3.18	3.26	3.34	3.44	3.62	3.82	3.46	3.80	4.17
Kerosene	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06
Distillate Fuel Oil	8.43	8.15	8.53	8.94	8.35	9.20	10.09	8.79	10.27	11.81
Residual Fuel Oil	1.55	1.49	1.50	1.52	1.50	1.52	1.56	1.50	1.55	1.59
Petrochemical Feedstocks	1.12	0.99	1.09	1.20	0.73	0.82	0.96	0.68	0.81	0.96
Other Petroleum[12]	4.21	3.94	4.17	4.42	3.80	4.06	4.46	3.57	4.10	4.57
Liquid Fuels and Other Petroleum Subtotal	38.35	37.59	38.81	40.23	37.50	40.14	43.11	37.49	42.02	46.82
Natural Gas	21.94	20.38	20.63	20.99	20.79	22.29	23.86	21.41	23.53	25.51
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]	1.32	1.10	1.11	1.12	1.12	1.23	1.29	1.22	1.29	1.34
Pipeline Natural Gas	0.64	0.61	0.61	0.63	0.62	0.72	0.76	0.70	0.74	0.80
Natural Gas Subtotal	23.91	22.10	22.35	22.73	22.52	24.24	25.91	23.33	25.56	27.66
Metallurgical Coal	0.58	0.50	0.52	0.55	0.44	0.50	0.56	0.28	0.36	0.44
Other Coal	21.79	21.33	21.66	21.92	21.48	22.78	23.57	22.34	24.20	25.95
Coal-to-Liquids Heat and Power	0.00	0.16	0.16	0.16	0.33	0.34	0.36	0.52	0.55	0.59
Net Coal Coke Imports	0.04	0.01	0.01	0.01	0.00	0.01	0.02	-0.01	-0.00	0.01
Coal Subtotal	22.41	21.99	22.35	22.64	22.25	23.63	24.52	23.14	25.11	26.99
Nuclear Power	8.46	8.75	8.75	8.75	9.29	9.29	9.35	9.26	9.41	9.98
Biofuels Heat and Coproducts[7]	1.03	0.77	0.77	0.80	1.14	1.49	1.52	1.70	2.56	3.35
Renewable Energy[18]	5.70	7.55	8.37	9.69	8.43	9.27	10.69	8.52	9.63	11.66
Liquid Hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Electricity Imports	0.11	0.07	0.07	0.07	0.08	0.08	0.09	0.05	0.09	0.13
Total	**100.09**	**98.94**	**101.61**	**105.04**	**101.35**	**108.26**	**115.32**	**103.62**	**114.51**	**126.72**
Energy Use and Related Statistics										
Delivered Energy Use	72.59	71.36	73.30	75.60	72.46	77.78	82.95	73.61	82.33	91.64
Total Energy Use	100.09	98.94	101.61	105.04	101.35	108.26	115.32	103.62	114.51	126.72
Ethanol Consumed in Motor Gasoline and E85	0.82	1.24	1.23	1.26	1.45	1.56	1.58	1.95	2.35	2.93
Population (millions)	305.37	322.09	326.70	333.30	340.14	358.62	380.29	352.44	390.70	433.29
Gross Domestic Product (billion 2000 dollars)	11652	12563	13289	14084	15802	17561	19425	18820	22362	25918
Carbon Dioxide Emissions (million metric tons)	5814.4	5612.7	5730.7	5858.7	5646.6	6015.8	6366.5	5767.5	6320.4	6865.2

[1]Includes wood used for residential heating. See Table A4 and/or Table A17 for estimates of nonmarketed renewable energy consumption for geothermal heat pumps, solar thermal hot water heating, and electricity generation from wind and solar photovoltaic sources.
[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 electricity generation from wind and solar photovoltaic sources.
[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]The energy content of biofuels feedstock minus the energy content of liquid fuel produced.
[8]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.
[9]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.
[10]Includes only kerosene type.
[11]Diesel fuel for on- and off- road use.
[12]Includes aviation gasoline and lubricants.
[13]Includes unfinished oils, natural gasoline, motor gasoline blending components, aviation gasoline, lubricants, still gas, asphalt, road oil, petroleum coke, and miscellaneous petroleum products.
[14]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.
[15]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.
[16]Includes conventional hydroelectric, geothermal, wood and wood waste, biogenic municipal waste, other biomass, wind, photovoltaic, and solar thermal sources. Excludes net electricity imports.
[17]Includes non-biogenic municipal waste not included above.
[18]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 2008 are model results and may differ slightly from official EIA data reports.
Sources: 2008 consumption based on: Energy Information Administration (EIA), *Annual Energy Review 2008*, DOE/EIA-0384(2008) (Washington, DC, June 2009). 2008 population and gross domestic product: IHS Global Insight Industry and Employment models, August 2009. 2008 carbon dioxide emissions: EIA, *Emissions of Greenhouse Gases in the United States 2008,* DOE/EIA-0573(2008) (Washington, DC, December 2009). **Projections:** EIA, AEO2010 National Energy Modeling System runs LM2010.D011110A. AEO2010R.D111809A. and HM2010.D020310A.

Table B3. Energy Prices by Sector and Source
(2008 Dollars per Million Btu, Unless Otherwise Noted)

Sector and Source	2008	Projections								
		2015			2025			2035		
		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	29.35	27.70	28.03	28.33	30.81	31.55	32.40	33.92	34.65	35.85
Distillate Fuel Oil	24.47	20.67	21.08	21.78	24.52	25.23	26.35	26.91	28.66	30.86
Natural Gas	13.48	11.29	11.56	11.77	12.15	12.29	13.12	13.08	14.40	15.28
Electricity	33.29	30.69	31.43	32.12	31.34	32.26	34.07	32.00	34.71	36.84
Commercial										
Liquefied Petroleum Gases	26.15	24.45	24.77	25.07	27.54	28.26	29.09	30.63	31.32	32.49
Distillate Fuel Oil	21.50	18.31	18.72	19.31	21.99	22.72	23.79	24.41	26.13	28.34
Residual Fuel Oil	15.52	12.90	13.13	13.35	15.95	16.54	17.00	18.48	18.84	19.26
Natural Gas	11.94	9.71	9.99	10.22	10.47	10.70	11.58	11.27	12.66	13.63
Electricity	30.47	25.64	26.55	27.34	26.60	27.72	29.62	27.37	30.37	32.76
Industrial[1]										
Liquefied Petroleum Gases	24.20	22.07	22.49	22.91	25.39	26.12	26.95	28.23	29.25	30.36
Distillate Fuel Oil	22.31	18.59	19.00	19.54	22.23	22.97	24.04	24.74	26.48	28.81
Residual Fuel Oil	16.31	16.23	16.47	16.70	18.61	19.23	19.99	21.10	21.72	22.95
Natural Gas[2]	9.11	6.21	6.45	6.62	6.89	7.02	7.77	7.53	8.73	9.50
Metallurgical Coal	4.49	5.05	5.08	5.11	5.22	5.24	5.25	4.94	5.06	5.25
Other Industrial Coal	2.84	2.66	2.69	2.70	2.59	2.63	2.66	2.65	2.71	2.80
Coal to Liquids	- -	1.45	1.42	1.42	1.42	1.49	1.50	1.49	1.51	1.52
Electricity	20.21	16.77	17.37	17.92	17.75	18.50	19.89	18.24	20.71	22.48
Transportation										
Liquefied Petroleum Gases[3]	29.93	27.54	27.88	28.21	30.61	31.36	32.22	33.66	34.38	35.58
E85[4]	26.93	23.96	25.55	25.85	28.29	28.86	29.90	30.69	32.23	33.75
Motor Gasoline[5]	26.76	25.13	25.37	25.56	28.21	28.87	29.87	30.69	32.33	34.35
Jet Fuel[6]	22.71	18.64	19.04	19.48	22.16	22.92	23.97	24.88	26.48	28.57
Diesel Fuel (distillate fuel oil)[7]	27.65	22.47	22.93	23.50	25.74	26.63	27.85	28.05	29.96	32.49
Residual Fuel Oil	14.49	13.33	13.58	13.65	15.28	15.93	16.76	17.87	18.60	19.86
Natural Gas[8]	15.96	13.04	13.37	13.66	13.14	13.43	14.44	13.33	14.78	15.85
Electricity	33.73	27.95	28.79	29.36	27.58	28.63	32.31	29.23	33.26	37.20
Electric Power[9]										
Distillate Fuel Oil	19.37	16.98	17.36	18.02	20.67	21.35	22.43	23.03	24.70	26.83
Residual Fuel Oil	14.56	15.28	15.53	15.71	17.58	18.30	19.19	20.27	21.12	22.48
Natural Gas	9.09	5.83	6.08	6.26	6.63	6.75	7.51	7.24	8.46	9.18
Steam Coal	2.05	1.99	2.01	2.02	1.96	1.99	2.02	2.02	2.09	2.16
Average Price to All Users[10]										
Liquefied Petroleum Gases	20.19	20.02	20.30	20.56	22.82	23.34	24.00	25.97	26.37	27.23
E85[4]	26.93	23.96	25.55	25.85	28.29	28.86	29.90	30.69	32.23	33.75
Motor Gasoline[5]	26.54	25.12	25.36	25.56	28.20	28.87	29.87	30.68	32.32	34.34
Jet Fuel	22.71	18.64	19.04	19.48	22.16	22.92	23.97	24.88	26.48	28.57
Distillate Fuel Oil	26.27	21.57	22.03	22.60	25.02	25.89	27.10	27.44	29.34	31.86
Residual Fuel Oil	14.77	14.00	14.26	14.39	16.11	16.80	17.64	18.69	19.46	20.72
Natural Gas	10.53	7.89	8.14	8.32	8.67	8.75	9.48	9.34	10.54	11.32
Metallurgical Coal	4.49	5.05	5.08	5.11	5.22	5.24	5.25	4.94	5.06	5.25
Other Coal	2.10	2.02	2.05	2.06	1.99	2.02	2.06	2.05	2.12	2.19
Coal to Liquids	- -	1.45	1.42	1.42	1.42	1.49	1.50	1.49	1.51	1.52
Electricity	28.81	25.27	25.95	26.56	26.34	27.17	28.78	27.28	29.87	31.85
Non-Renewable Energy Expenditures by Sector (billion 2008 dollars)										
Residential	254.66	223.63	230.89	238.11	242.49	258.70	283.44	258.49	301.11	342.71
Commercial	191.19	169.37	176.90	184.32	195.16	210.07	232.66	224.19	261.07	297.41
Industrial	244.81	196.86	213.14	231.17	206.90	241.75	286.98	202.88	267.18	339.55
Transportation	705.86	629.34	655.77	684.37	717.69	782.71	870.40	782.63	908.01	1057.29
Total Non-Renewable Expenditures	1396.52	1219.20	1276.69	1337.96	1362.23	1493.23	1673.48	1468.19	1737.37	2036.96
Transportation Renewable Expenditures	0.17	1.74	0.21	0.20	12.40	15.06	13.26	38.59	56.42	86.21
Total Expenditures	**1396.69**	**1220.94**	**1276.90**	**1338.17**	**1374.64**	**1508.29**	**1686.74**	**1506.79**	**1793.79**	**2123.18**

Table B3. Energy Prices by Sector and Source (Continued)
(Nominal Dollars per Million Btu, Unless Otherwise Noted)

Sector and Source	2008	Projections								
		2015			2025			2035		
		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	29.35	32.04	31.23	30.13	46.47	42.82	39.03	66.34	58.23	50.48
Distillate Fuel Oil	24.47	23.91	23.49	23.16	36.99	34.24	31.74	52.63	48.16	43.46
Natural Gas	13.48	13.06	12.88	12.51	18.34	16.68	15.81	25.59	24.20	21.52
Electricity	33.29	35.50	35.02	34.16	47.27	43.78	41.04	62.60	58.33	51.87
Commercial										
Liquefied Petroleum Gases	26.15	28.28	27.61	26.67	41.54	38.35	35.05	59.90	52.64	45.75
Distillate Fuel Oil	21.50	21.18	20.86	20.54	33.17	30.83	28.66	47.74	43.92	39.91
Residual Fuel Oil	15.52	14.93	14.63	14.19	24.05	22.45	20.48	36.14	31.66	27.12
Natural Gas	11.94	11.23	11.14	10.87	15.80	14.53	13.95	22.04	21.27	19.19
Electricity	30.47	29.66	29.58	29.08	40.13	37.62	35.68	53.53	51.04	46.14
Industrial[1]										
Liquefied Petroleum Gases	24.20	25.53	25.06	24.37	38.30	35.45	32.47	55.21	49.15	42.76
Distillate Fuel Oil	22.31	21.51	21.18	20.78	33.53	31.18	28.96	48.39	44.51	40.57
Residual Fuel Oil	16.31	18.77	18.35	17.77	28.07	26.10	24.08	41.27	36.50	32.32
Natural Gas[2]	9.11	7.18	7.18	7.04	10.39	9.52	9.36	14.74	14.67	13.38
Metallurgical Coal	4.49	5.84	5.66	5.43	7.87	7.11	6.32	9.66	8.50	7.39
Other Industrial Coal	2.84	3.08	3.00	2.87	3.91	3.56	3.21	5.17	4.55	3.94
Coal to Liquids	- -	1.67	1.58	1.51	2.14	2.02	1.80	2.91	2.53	2.13
Electricity	20.21	19.40	19.36	19.06	26.78	25.11	23.96	35.68	34.80	31.65
Transportation										
Liquefied Petroleum Gases[3]	29.93	31.86	31.07	30.00	46.17	42.56	38.81	65.83	57.77	50.10
E85[4]	26.93	27.72	28.47	27.49	42.68	39.17	36.02	60.03	54.17	47.52
Motor Gasoline[5]	26.76	29.07	28.27	27.19	42.55	39.18	35.99	60.02	54.33	48.37
Jet Fuel[6]	22.71	21.56	21.21	20.71	33.43	31.10	28.88	48.65	44.51	40.24
Diesel Fuel (distillate fuel oil)[7]	27.65	25.99	25.56	24.99	38.83	36.13	33.54	54.87	50.35	45.75
Residual Fuel Oil	14.49	15.42	15.13	14.52	23.05	21.63	20.19	34.95	31.26	27.96
Natural Gas[8]	15.96	15.09	14.90	14.52	19.83	18.23	17.39	26.07	24.84	22.32
Electricity	33.73	32.33	32.08	31.22	41.60	38.86	38.92	57.16	55.89	52.38
Electric Power[9]										
Distillate Fuel Oil	19.37	19.64	19.35	19.16	31.18	28.98	27.02	45.05	41.52	37.79
Residual Fuel Oil	14.56	17.68	17.30	16.71	26.51	24.83	23.11	39.64	35.49	31.65
Natural Gas	9.09	6.75	6.77	6.66	10.00	9.17	9.05	14.16	14.22	12.93
Steam Coal	2.05	2.30	2.24	2.15	2.95	2.69	2.44	3.96	3.51	3.04

Table B3. Energy Prices by Sector and Source (Continued)
(Nominal Dollars per Million Btu, Unless Otherwise Noted)

Sector and Source	2008	Projections								
		2015			2025			2035		
		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	20.19	23.16	22.62	21.86	34.43	31.68	28.91	50.79	44.32	38.35
E85[4]	26.93	27.72	28.47	27.49	42.68	39.17	36.02	60.03	54.17	47.52
Motor Gasoline[5]	26.54	29.06	28.27	27.18	42.55	39.17	35.98	60.01	54.32	48.36
Jet Fuel	22.71	21.56	21.21	20.71	33.43	31.10	28.88	48.65	44.51	40.24
Distillate Fuel Oil	26.27	24.95	24.55	24.04	37.74	35.14	32.64	53.67	49.31	44.87
Residual Fuel Oil	14.77	16.20	15.89	15.31	24.31	22.80	21.25	36.56	32.70	29.18
Natural Gas	10.53	9.13	9.07	8.85	13.07	11.88	11.42	18.28	17.71	15.93
Metallurgical Coal	4.49	5.84	5.66	5.43	7.87	7.11	6.32	9.66	8.50	7.39
Other Coal	2.10	2.34	2.28	2.19	3.00	2.74	2.48	4.02	3.56	3.08
Coal to Liquids	- -	1.67	1.58	1.51	2.14	2.02	1.80	2.91	2.53	2.13
Electricity	28.81	29.23	28.92	28.25	39.74	36.87	34.67	53.36	50.19	44.85
Non-Renewable Energy Expenditures by Sector (billion nominal dollars)										
Residential	254.66	258.67	257.29	253.23	365.80	351.09	341.43	505.59	506.03	482.60
Commercial	191.19	195.92	197.13	196.02	294.40	285.09	280.27	438.51	438.74	418.80
Industrial	244.81	227.71	237.51	245.85	312.11	328.09	345.70	396.82	449.00	478.16
Transportation	705.86	727.96	730.78	727.84	1082.64	1062.24	1048.50	1530.76	1525.95	1488.86
Total Non-Renewable Expenditures	1396.52	1410.26	1422.72	1422.95	2054.95	2026.51	2015.90	2871.68	2919.72	2868.42
Transportation Renewable Expenditures	0.17	2.01	0.24	0.22	18.71	20.44	15.97	75.49	94.81	121.41
Total Expenditures	**1396.69**	**1412.27**	**1422.95**	**1423.17**	**2073.65**	**2046.94**	**2031.87**	**2947.17**	**3014.53**	**2989.83**

[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 2008 are model results and may differ slightly from official EIA data reports.
Sources: 2008 prices for motor gasoline, distillate fuel oil, and jet fuel are based on prices in the Energy Information Administration (EIA), *Petroleum Marketing Annual 2008*, DOE/EIA-0487(2008) (Washington, DC, August 2009). 2008 residential and commercial natural gas delivered prices: EIA, *Natural Gas Monthly*, DOE/EIA-0130(2009/07) (Washington, DC, July 2009). 2008 industrial natural gas delivered prices are estimated based on: EIA, *Manufacturing Energy Consumption Survey* and industrial and wellhead prices from the *Natural Gas Annual 2007*, DOE/EIA-0131(2007) (Washington, DC, January 2009) and the *Natural Gas Monthly*, DOE/EIA-0130(2009/07) (Washington, DC, July 2009). 2008 transportation sector natural gas delivered prices are model results. 2008 electric power sector natural gas prices: EIA, *Electric Power Monthly*, DOE/EIA-0226, April 2008 and April 2009, Table 4.13.B. 2008 coal prices based on: EIA, *Quarterly Coal Report, October-December 2008*, DOE/EIA-0121(2008/4Q) (Washington, DC, March 2009) and EIA, AEO2010 National Energy Modeling System run AEO2010R.D111809A. 2008 electricity prices: EIA, *Annual Energy Review 2008*, DOE/EIA-0384(2008) (Washington, DC, June 2009). 2008 E85 prices derived from monthly prices in the Clean Cities Alternative Fuel Price Report.
Projections: EIA, AEO2010 National Energy Modeling System runs LM2010.D011110A, AEO2010R.D111809A, and HM2010.D020310A.

Table B4. Macroeconomic Indicators
(Billion 2000 Chain-Weighted Dollars, Unless Otherwise Noted)

Indicators	2008	Projections								
		2015			2025			2035		
		Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth
Real Gross Domestic Product	**11652**	**12563**	**13289**	**14084**	**15802**	**17561**	**19425**	**18820**	**22362**	**25918**
Components of Real Gross Domestic Product										
Real Consumption	8272	8901	9343	9832	11292	12348	13464	13708	15932	18176
Real Investment	1689	1911	2178	2444	2507	2988	3502	3274	4104	4819
Real Government Spending	2070	2012	2085	2173	2128	2319	2524	2190	2569	2969
Real Exports	1514	1933	2000	2087	3230	3773	4369	5219	6211	7241
Real Imports	1904	2147	2240	2320	3381	3574	3732	5546	5881	6120
Energy Intensity										
(thousand Btu per 2000 dollar of GDP)										
Delivered Energy	6.23	5.68	5.52	5.37	4.59	4.43	4.27	3.91	3.68	3.54
Total Energy	8.59	7.88	7.65	7.46	6.41	6.16	5.94	5.51	5.12	4.89
Price Indices										
GDP Chain-Type Price Index (2000=1.000)	1.225	1.417	1.365	1.303	1.848	1.662	1.476	2.396	2.059	1.725
Consumer Price Index (1982-4=1)										
All-urban	2.15	2.52	2.43	2.32	3.41	3.07	2.73	4.54	3.92	3.31
Energy Commodities and Services	2.36	2.46	2.41	2.33	3.51	3.23	3.00	4.87	4.46	3.95
Wholesale Price Index (1982=1.00)										
All Commodities	1.90	2.02	1.93	1.83	2.55	2.24	1.95	3.13	2.62	2.11
Fuel and Power	2.14	2.08	2.04	1.98	3.01	2.76	2.59	4.24	3.92	3.50
Metals and Metal Products	2.13	2.26	2.19	2.10	2.61	2.36	2.11	2.82	2.45	2.08
Interest Rates (percent, nominal)										
Federal Funds Rate	1.93	5.32	4.72	4.15	5.79	5.07	4.44	5.94	5.19	4.48
10-Year Treasury Note	3.67	6.06	5.44	4.81	6.61	5.84	5.18	6.62	5.89	5.26
AA Utility Bond Rate	6.19	7.74	7.22	6.69	8.59	7.79	7.08	9.20	8.30	7.39
Value of Shipments (billion 2000 dollars)										
Service Sectors	18812	20075	20956	22027	24883	27205	29753	31251	36289	41680
Total Industrial	5408	5673	6044	6444	6118	6997	7922	6252	7786	9397
Non-manufacturing	1394	1403	1547	1703	1438	1673	1909	1463	1776	2048
Manufacturing	4014	4269	4497	4741	4681	5324	6013	4788	6010	7348
Energy-Intensive	1230	1258	1315	1382	1332	1467	1611	1318	1542	1777
Non-Energy Intensive	2784	3011	3182	3360	3349	3856	4402	3470	4468	5571
Total Shipments	**24220**	**25747**	**27001**	**28471**	**31002**	**34202**	**37675**	**37503**	**44074**	**51077**
Population and Employment (millions)										
Population with Armed Forces Overseas	305.4	322.1	326.7	333.3	340.1	358.6	380.3	352.4	390.7	433.3
Population, aged 16 and over	240.0	253.5	257.4	262.5	271.6	283.6	297.7	285.7	310.7	338.7
Population, over age 65	38.8	46.7	47.0	47.5	62.8	64.2	65.8	74.6	77.7	81.2
Employment, Nonfarm	137.0	133.0	142.5	152.5	146.2	157.4	169.2	153.9	171.4	189.4
Employment, Manufacturing	13.4	11.8	12.2	12.4	10.8	11.3	11.8	11.7	12.8	13.9
Key Labor Indicators										
Labor Force (millions)	154.3	158.4	161.4	165.6	164.1	171.4	179.3	173.7	183.4	193.4
Non-farm Labor Productivity (1992=1.00)	1.41	1.53	1.57	1.63	1.81	1.96	2.12	2.10	2.39	2.69
Unemployment Rate (percent)	5.81	7.47	7.32	7.15	5.52	5.31	5.15	5.63	5.49	5.30
Key Indicators for Energy Demand										
Real Disposable Personal Income	8753	9644	10091	10598	12981	13974	15017	16133	18168	20195
Housing Starts (millions)	0.98	1.54	1.88	2.25	1.40	1.89	2.40	1.07	1.70	2.24
Commercial Floorspace (billion square feet)	78.8	83.3	85.1	87.1	92.1	97.5	103.1	101.6	110.5	120.0
Unit Sales of Light-Duty Vehicles (millions)	13.13	16.44	17.25	18.40	16.13	17.92	19.87	17.39	20.09	22.94

GDP = Gross domestic product.
Btu = British thermal unit.
Sources: 2008: IHS Global Insight Industry and Employment models, August 2009. **Projections:** Energy Information Administration, AEO2010 National Energy Modeling System runs LM2010.D011110A, AEO2010R.D111809A, and HM2010.D020310A.

Price Case Comparisons

Table C1. Total Energy Supply, Disposition, and Price Summary
(Quadrillion Btu per Year, Unless Otherwise Noted)

Supply, Disposition, and Prices	2008	Projections								
		2015			2025			2035		
		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	10.51	11.95	12.41	12.56	10.64	13.22	14.67	9.40	13.50	14.83
Natural Gas Plant Liquids	2.57	2.32	2.27	2.22	2.36	2.24	2.26	2.40	2.37	2.35
Dry Natural Gas	21.14	20.43	19.83	19.39	21.52	21.90	22.96	24.64	23.92	25.61
Coal[1]	23.86	22.97	23.31	23.61	24.12	24.36	25.74	24.64	25.19	27.57
Nuclear Power	8.46	8.75	8.75	8.75	9.29	9.29	9.29	9.26	9.41	9.44
Hydropower	2.46	2.95	2.96	2.96	2.97	2.98	2.96	2.98	2.99	3.01
Biomass[2]	3.97	4.63	4.60	4.64	6.32	6.90	8.68	6.78	9.27	12.08
Other Renewable Energy[3]	1.17	2.55	3.01	3.03	2.68	3.07	3.10	2.88	3.36	3.40
Other[4]	0.10	0.53	0.73	1.18	0.68	0.94	1.39	0.66	0.81	1.07
Total	**74.23**	**77.08**	**77.88**	**78.36**	**80.58**	**84.91**	**91.06**	**83.65**	**90.83**	**99.36**
Imports										
Crude Oil	21.39	22.19	19.66	18.25	25.70	19.21	13.21	29.87	19.34	11.95
Liquid Fuels and Other Petroleum[5]	6.38	5.79	5.54	5.29	6.35	5.76	4.78	7.29	6.08	4.96
Natural Gas	4.06	3.90	3.59	3.46	4.50	3.94	3.24	3.68	3.49	2.84
Other Imports[6]	0.96	0.79	0.79	0.78	0.59	0.88	1.36	0.47	1.32	1.78
Total	**32.79**	**32.67**	**29.58**	**27.79**	**37.14**	**29.80**	**22.58**	**41.31**	**30.23**	**21.54**
Exports										
Petroleum[7]	3.71	3.52	3.53	3.58	3.90	3.91	3.71	4.08	4.12	3.86
Natural Gas	1.01	1.17	1.14	1.12	1.80	1.69	1.64	2.16	1.96	1.84
Coal	2.07	1.49	1.49	1.49	1.05	1.20	1.19	0.75	0.79	0.83
Total	**6.80**	**6.18**	**6.16**	**6.18**	**6.76**	**6.80**	**6.54**	**7.00**	**6.87**	**6.53**
Discrepancy[8]	**0.13**	**-0.23**	**-0.30**	**-0.31**	**-0.22**	**-0.35**	**-0.30**	**-0.20**	**-0.32**	**-0.38**
Consumption										
Liquid Fuels and Other Petroleum[9]	38.35	40.88	38.81	37.75	43.83	40.14	37.45	47.61	42.02	38.94
Natural Gas	23.91	23.22	22.35	21.81	24.28	24.24	24.28	26.21	25.56	25.80
Coal[10]	22.41	22.05	22.35	22.59	23.41	23.63	24.63	24.10	25.11	26.59
Nuclear Power	8.46	8.75	8.75	8.75	9.29	9.29	9.29	9.26	9.41	9.44
Hydropower	2.46	2.95	2.96	2.96	2.97	2.98	2.96	2.98	2.99	3.01
Biomass[11]	3.10	3.21	3.17	3.18	4.52	4.70	5.48	4.89	5.83	7.32
Other Renewable Energy[3]	1.17	2.55	3.01	3.03	2.68	3.07	3.10	2.88	3.36	3.40
Other[12]	0.24	0.20	0.20	0.20	0.21	0.21	0.22	0.24	0.22	0.25
Total	**100.09**	**103.80**	**101.61**	**100.27**	**111.19**	**108.26**	**107.41**	**118.17**	**114.51**	**114.75**
Prices (2008 dollars per unit)										
Petroleum (dollars per barrel)										
Imported Low Sulfur Light Crude Oil Price[13]	99.57	51.59	94.52	144.78	51.73	115.09	196.01	51.44	133.22	209.60
Imported Crude Oil Price[13]	92.61	43.88	86.88	137.01	41.36	104.49	185.85	41.99	121.37	199.65
Natural Gas (dollars per million Btu)										
Price at Henry Hub	8.86	5.59	6.27	6.78	6.88	6.99	7.39	8.12	8.88	9.49
Wellhead Price[14]	7.85	4.94	5.54	5.99	6.08	6.18	6.53	7.18	7.84	8.38
Natural Gas (dollars per thousand cubic feet)										
Wellhead Price[14]	8.07	5.08	5.70	6.16	6.25	6.35	6.71	7.38	8.06	8.62
Coal (dollars per ton)										
Minemouth Price[15]	31.26	29.00	30.38	31.40	26.66	28.19	29.71	26.45	28.10	30.08
Coal (dollars per million Btu)										
Minemouth Price[15]	1.55	1.45	1.52	1.57	1.36	1.44	1.53	1.35	1.44	1.57
Average Delivered Price[16]	2.16	1.99	2.11	2.21	1.95	2.07	2.21	1.98	2.13	2.28
Average Electricity Price (cents per kilowatthour)	9.8	8.5	8.9	9.2	9.0	9.3	9.5	9.9	10.2	10.5

Table C1. Total Energy Supply and Disposition Summary (Continued)
(Quadrillion Btu per Year, Unless Otherwise Noted)

Supply, Disposition, and Prices	2008	Projections								
		2015			2025			2035		
		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]	99.57	57.24	105.33	161.68	71.01	156.20	263.01	86.58	223.88	348.67
Imported Crude Oil Price[13]	92.61	48.68	96.82	153.00	56.78	141.80	249.37	70.68	203.97	332.11
Natural Gas (dollars per million Btu)										
Price at Henry Hub	8.86	6.20	6.99	7.57	9.45	9.49	9.91	13.67	14.92	15.79
Wellhead Price[14]	7.85	5.48	6.17	6.69	8.35	8.38	8.76	12.08	13.18	13.94
Natural Gas (dollars per thousand cubic feet)										
Wellhead Price[14]	8.07	5.63	6.35	6.87	8.58	8.62	9.00	12.41	13.55	14.34
Coal (dollars per ton)										
Minemouth Price[15]	31.26	32.18	33.86	35.07	36.60	38.25	39.87	44.51	47.23	50.03
Coal (dollars per million Btu)										
Minemouth Price[15]	1.55	1.61	1.69	1.76	1.86	1.95	2.06	2.27	2.43	2.61
Average Delivered Price[16]	2.16	2.21	2.35	2.47	2.68	2.81	2.96	3.33	3.58	3.79
Average Electricity Price (cents per kilowatthour)	9.8	9.4	9.9	10.2	12.4	12.6	12.8	16.6	17.1	17.5

[1]Includes waste coal.
[2]Includes grid-connected electricity from wood and wood 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 and crude oil consumed as a fuel. Refer to Table A17 for detailed renewable liquid fuels consumption.
[10]Excludes coal converted to coal-based synthetic liquids and coal-based synthetic natural gas.
[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 2008 are model results and may differ slightly from official EIA data reports.
Sources: 2008 natural gas supply values and natural gas wellhead price: EIA, *Natural Gas Monthly*, DOE/EIA-0130(2009/07) (Washington, DC, July 2009). 2008 coal minemouth and delivered coal prices: EIA, *Annual Energy Review 2008*, DOE/EIA-0384(2008) (Washington, DC, June 2009). 2008 petroleum supply values: EIA, *Petroleum Supply Annual 2008,* DOE/EIA-0340(2008)/1 (Washington, DC, June 2009). 2008 low sulfur light crude oil price: EIA, Form EIA-856, "Monthly Foreign Crude Oil Acquisition Report." Other 2008 coal values: *Quarterly Coal Report, October-December 2008*, DOE/EIA-0121(2008/4Q) (Washington, DC, March 2009). Other 2008 values: EIA, *Annual Energy Review 2008*, DOE/EIA-0384(2008) (Washington, DC, June 2009). **Projections:** EIA, AEO2010 National Energy Modeling System runs LP2010.D011910A, AEO2010R.D111809A, and HP2010.D011910A.

Table C2. Energy Consumption by Sector and Source
(Quadrillion Btu per Year, Unless Otherwise Noted)

Sector and Source	2008	2015 Low Oil Price	2015 Reference	2015 High Oil Price	2025 Low Oil Price	2025 Reference	2025 High Oil Price	2035 Low Oil Price	2035 Reference	2035 High Oil Price
Energy Consumption										
Residential										
Liquefied Petroleum Gases	0.45	0.44	0.41	0.38	0.45	0.40	0.35	0.47	0.40	0.35
Kerosene	0.04	0.04	0.04	0.03	0.04	0.03	0.03	0.04	0.03	0.03
Distillate Fuel Oil	0.68	0.66	0.59	0.55	0.57	0.49	0.43	0.50	0.41	0.36
Liquid Fuels and Other Petroleum Subtotal	1.18	1.13	1.04	0.97	1.06	0.92	0.82	1.01	0.85	0.74
Natural Gas	5.01	4.91	4.85	4.80	5.05	5.04	5.02	5.06	5.01	4.99
Coal	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Renewable Energy[1]	0.45	0.35	0.40	0.45	0.35	0.42	0.49	0.34	0.43	0.50
Electricity	4.71	4.84	4.78	4.72	5.36	5.30	5.25	5.89	5.83	5.77
Delivered Energy	**11.34**	**11.24**	**11.07**	**10.94**	**11.83**	**11.69**	**11.58**	**12.31**	**12.12**	**12.01**
Electricity Related Losses	10.20	10.23	10.24	10.20	11.17	11.08	10.89	11.87	11.79	11.57
Total	**21.54**	**21.46**	**21.31**	**21.15**	**23.00**	**22.76**	**22.47**	**24.18**	**23.92**	**23.58**
Commercial										
Liquefied Petroleum Gases	0.08	0.09	0.09	0.08	0.09	0.09	0.09	0.09	0.09	0.09
Motor Gasoline[2]	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06
Kerosene	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Distillate Fuel Oil	0.36	0.35	0.31	0.28	0.35	0.28	0.24	0.36	0.26	0.23
Residual Fuel Oil	0.07	0.10	0.09	0.08	0.10	0.09	0.08	0.10	0.09	0.08
Liquid Fuels and Other Petroleum Subtotal	0.58	0.61	0.55	0.51	0.61	0.53	0.49	0.63	0.52	0.48
Natural Gas	3.21	3.39	3.32	3.27	3.56	3.55	3.53	3.81	3.79	3.77
Coal	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07
Renewable Energy[3]	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10
Electricity	4.61	5.06	5.00	4.96	5.82	5.76	5.72	6.63	6.55	6.51
Delivered Energy	**8.58**	**9.23**	**9.04**	**8.91**	**10.17**	**10.00**	**9.90**	**11.24**	**11.04**	**10.93**
Electricity Related Losses	10.00	10.69	10.72	10.71	12.13	12.03	11.85	13.34	13.27	13.05
Total	**18.58**	**19.92**	**19.77**	**19.62**	**22.30**	**22.03**	**21.76**	**24.59**	**24.30**	**23.98**
Industrial[4]										
Liquefied Petroleum Gases	2.14	2.19	2.31	2.64	2.12	2.55	2.60	2.00	2.35	2.40
Motor Gasoline[2]	0.30	0.31	0.30	0.30	0.31	0.30	0.30	0.31	0.30	0.30
Distillate Fuel Oil	1.19	1.22	1.19	1.17	1.21	1.17	1.17	1.23	1.17	1.17
Residual Fuel Oil	0.18	0.22	0.14	0.13	0.25	0.14	0.12	0.25	0.13	0.12
Petrochemical Feedstocks	1.12	1.09	1.09	0.65	1.11	0.82	0.69	1.09	0.81	0.70
Other Petroleum[5]	4.05	4.38	4.01	3.73	4.65	3.89	3.35	4.93	3.92	3.23
Liquid Fuels and Other Petroleum Subtotal	8.99	9.41	9.04	8.61	9.65	8.87	8.23	9.82	8.70	7.92
Natural Gas	6.84	7.02	7.08	7.15	6.91	7.14	7.16	6.73	6.91	6.90
Natural-Gas-to-Liquids Heat and Power	0.00	0.00	0.00	0.00	0.00	0.00	0.27	0.00	0.00	0.65
Lease and Plant Fuel[6]	1.32	1.14	1.11	1.09	1.14	1.23	1.29	1.28	1.29	1.40
Natural Gas Subtotal	8.16	8.16	8.19	8.24	8.05	8.37	8.72	8.01	8.20	8.94
Metallurgical Coal	0.58	0.55	0.52	0.50	0.52	0.50	0.48	0.39	0.36	0.35
Other Industrial Coal	1.17	1.09	1.07	1.06	1.09	1.07	1.07	1.05	1.04	1.03
Coal-to-Liquids Heat and Power	0.00	0.11	0.16	0.22	0.13	0.34	1.35	0.13	0.55	2.08
Net Coal Coke Imports	0.04	0.01	0.01	0.01	0.01	0.01	0.01	-0.00	-0.00	-0.00
Coal Subtotal	1.79	1.76	1.76	1.79	1.75	1.92	2.90	1.57	1.95	3.46
Biofuels Heat and Coproducts[7]	1.03	0.80	0.77	0.81	1.18	1.49	2.51	1.23	2.56	4.19
Renewable Energy[8]	1.50	1.63	1.59	1.57	1.78	1.74	1.71	1.88	1.83	1.80
Electricity	3.35	3.49	3.40	3.33	3.55	3.49	3.44	3.53	3.47	3.41
Delivered Energy	**24.81**	**25.24**	**24.76**	**24.36**	**25.95**	**25.88**	**27.51**	**26.04**	**26.70**	**29.71**
Electricity Related Losses	7.26	7.37	7.29	7.19	7.39	7.29	7.14	7.12	7.01	6.83
Total	**32.07**	**32.61**	**32.05**	**31.55**	**33.34**	**33.18**	**34.65**	**33.16**	**33.72**	**36.54**

Table C2. Energy Consumption by Sector and Source (Continued)
(Quadrillion Btu per Year, Unless Otherwise Noted)

Sector and Source	2008	Projections								
		2015			2025			2035		
		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	0.02	0.02	0.02	0.02	0.02	0.02	0.03	0.03	0.03
E85[9]	0.01	0.01	0.01	0.21	0.22	0.52	2.53	0.02	1.75	3.86
Motor Gasoline[2]	16.76	18.14	17.02	16.45	19.37	16.91	13.15	21.54	16.44	12.34
Jet Fuel[10]	3.15	3.30	3.26	3.21	3.64	3.62	3.59	3.82	3.80	3.78
Distillate Fuel Oil[11]	6.09	6.47	6.32	6.20	7.36	7.13	7.02	8.71	8.28	8.14
Residual Fuel Oil	0.93	0.94	0.94	0.94	0.96	0.96	0.96	0.97	0.97	0.98
Other Petroleum[12]	0.17	0.18	0.17	0.17	0.18	0.18	0.18	0.19	0.19	0.19
Liquid Fuels and Other Petroleum Subtotal	27.14	29.05	27.73	27.20	31.74	29.34	27.45	35.28	31.47	29.31
Pipeline Fuel Natural Gas	0.64	0.63	0.61	0.61	0.65	0.72	0.72	0.77	0.74	0.74
Compressed Natural Gas	0.04	0.05	0.05	0.07	0.05	0.11	0.22	0.06	0.19	0.36
Liquid Hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Electricity	0.02	0.03	0.03	0.03	0.03	0.04	0.05	0.04	0.06	0.08
Delivered Energy	**27.85**	**29.75**	**28.42**	**27.90**	**32.48**	**30.21**	**28.44**	**36.16**	**32.46**	**30.49**
Electricity Related Losses	0.05	0.05	0.05	0.05	0.07	0.08	0.10	0.09	0.11	0.16
Total	**27.90**	**29.81**	**28.48**	**27.95**	**32.55**	**30.29**	**28.54**	**36.25**	**32.58**	**30.65**
Delivered Energy Consumption for All Sectors										
Liquefied Petroleum Gases	2.70	2.73	2.82	3.13	2.68	3.06	3.06	2.59	2.87	2.87
E85[9]	0.01	0.01	0.01	0.21	0.22	0.52	2.53	0.02	1.75	3.86
Motor Gasoline[2]	17.12	18.51	17.38	16.81	19.73	17.28	13.51	21.91	16.80	12.71
Jet Fuel[10]	3.15	3.30	3.26	3.21	3.64	3.62	3.59	3.82	3.80	3.78
Kerosene	0.06	0.06	0.06	0.06	0.07	0.06	0.06	0.07	0.06	0.06
Distillate Fuel Oil	8.33	8.70	8.40	8.19	9.49	9.07	8.86	10.81	10.13	9.90
Residual Fuel Oil	1.19	1.26	1.17	1.15	1.30	1.18	1.16	1.33	1.19	1.18
Petrochemical Feedstocks	1.12	1.09	1.09	0.65	1.11	0.82	0.69	1.09	0.81	0.70
Other Petroleum[13]	4.21	4.54	4.17	3.89	4.82	4.06	3.51	5.10	4.10	3.40
Liquid Fuels and Other Petroleum Subtotal	37.89	40.20	38.35	37.30	43.06	39.66	36.98	46.74	41.53	38.46
Natural Gas	15.10	15.36	15.31	15.29	15.58	15.84	15.92	15.66	15.91	16.02
Natural-Gas-to-Liquids Heat and Power	0.00	0.00	0.00	0.00	0.00	0.00	0.27	0.00	0.00	0.65
Lease and Plant Fuel[6]	1.32	1.14	1.11	1.09	1.14	1.23	1.29	1.28	1.29	1.40
Pipeline Natural Gas	0.64	0.63	0.61	0.61	0.65	0.72	0.72	0.77	0.74	0.74
Natural Gas Subtotal	17.07	17.13	17.03	16.99	17.37	17.79	18.20	17.71	17.94	18.80
Metallurgical Coal	0.58	0.55	0.52	0.50	0.52	0.50	0.48	0.39	0.36	0.35
Other Coal	1.24	1.16	1.15	1.14	1.16	1.15	1.14	1.13	1.11	1.11
Coal-to-Liquids Heat and Power	0.00	0.11	0.16	0.22	0.13	0.34	1.35	0.13	0.55	2.08
Net Coal Coke Imports	0.04	0.01	0.01	0.01	0.01	0.01	0.01	-0.00	-0.00	-0.00
Coal Subtotal	1.86	1.83	1.84	1.87	1.82	2.00	2.97	1.64	2.02	3.53
Biofuels Heat and Coproducts[7]	1.03	0.80	0.77	0.81	1.18	1.49	2.51	1.23	2.56	4.19
Renewable Energy[14]	2.05	2.08	2.10	2.11	2.23	2.27	2.30	2.33	2.37	2.40
Liquid Hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Electricity	12.69	13.41	13.20	13.03	14.76	14.58	14.46	16.10	15.90	15.77
Delivered Energy	**72.59**	**75.45**	**73.30**	**72.11**	**80.43**	**77.78**	**77.44**	**85.76**	**82.33**	**83.15**
Electricity Related Losses	27.50	28.35	28.31	28.16	30.75	30.48	29.97	32.41	32.19	31.60
Total	**100.09**	**103.80**	**101.61**	**100.27**	**111.19**	**108.26**	**107.41**	**118.17**	**114.51**	**114.75**
Electric Power[15]										
Distillate Fuel Oil	0.10	0.13	0.12	0.12	0.14	0.13	0.13	0.15	0.14	0.14
Residual Fuel Oil	0.36	0.55	0.33	0.33	0.62	0.34	0.34	0.72	0.35	0.35
Liquid Fuels and Other Petroleum Subtotal	0.47	0.68	0.46	0.45	0.76	0.48	0.47	0.87	0.49	0.49
Natural Gas	6.84	6.09	5.32	4.82	6.91	6.45	6.07	8.49	7.62	7.00
Steam Coal	20.55	20.22	20.51	20.73	21.59	21.63	21.66	22.47	23.09	23.05
Nuclear Power	8.46	8.75	8.75	8.75	9.29	9.29	9.29	9.26	9.41	9.44
Renewable Energy[16]	3.65	5.82	6.27	6.25	6.76	7.00	6.73	7.19	7.26	7.14
Electricity Imports	0.11	0.07	0.07	0.07	0.08	0.08	0.09	0.10	0.09	0.12
Total[17]	**40.20**	**41.76**	**41.51**	**41.19**	**45.52**	**45.06**	**44.43**	**48.51**	**48.09**	**47.37**

Table C2. Energy Consumption by Sector and Source (Continued)
(Quadrillion Btu per Year, Unless Otherwise Noted)

Sector and Source	2008	Projections								
		2015			2025			2035		
		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	2.70	2.73	2.82	3.13	2.68	3.06	3.06	2.59	2.87	2.87
E85[9]	0.01	0.01	0.01	0.21	0.22	0.52	2.53	0.02	1.75	3.86
Motor Gasoline[2]	17.12	18.51	17.38	16.81	19.73	17.28	13.51	21.91	16.80	12.71
Jet Fuel[10]	3.15	3.30	3.26	3.21	3.64	3.62	3.59	3.82	3.80	3.78
Kerosene	0.06	0.06	0.06	0.06	0.07	0.06	0.06	0.07	0.06	0.06
Distillate Fuel Oil	8.43	8.83	8.53	8.31	9.63	9.20	8.99	10.97	10.27	10.04
Residual Fuel Oil	1.55	1.81	1.50	1.48	1.93	1.52	1.50	2.04	1.55	1.53
Petrochemical Feedstocks	1.12	1.09	1.09	0.65	1.11	0.82	0.69	1.09	0.81	0.70
Other Petroleum[13]	4.21	4.54	4.17	3.89	4.82	4.06	3.51	5.10	4.10	3.40
Liquid Fuels and Other Petroleum Subtotal	38.35	40.88	38.81	37.75	43.83	40.14	37.45	47.61	42.02	38.94
Natural Gas	21.94	21.45	20.63	20.11	22.48	22.29	21.99	24.15	23.53	23.01
Natural-Gas-to-Liquids Heat and Power	0.00	0.00	0.00	0.00	0.00	0.00	0.27	0.00	0.00	0.65
Lease and Plant Fuel[6]	1.32	1.14	1.11	1.09	1.14	1.23	1.29	1.28	1.29	1.40
Pipeline Natural Gas	0.64	0.63	0.61	0.61	0.65	0.72	0.72	0.77	0.74	0.74
Natural Gas Subtotal	23.91	23.22	22.35	21.81	24.28	24.24	24.28	26.21	25.56	25.80
Metallurgical Coal	0.58	0.55	0.52	0.50	0.52	0.50	0.48	0.39	0.36	0.35
Other Coal	21.79	21.38	21.66	21.86	22.75	22.78	22.80	23.59	24.20	24.16
Coal-to-Liquids Heat and Power	0.00	0.11	0.16	0.22	0.13	0.34	1.35	0.13	0.55	2.08
Net Coal Coke Imports	0.04	0.01	0.01	0.01	0.01	0.01	0.01	-0.00	-0.00	-0.00
Coal Subtotal	22.41	22.05	22.35	22.59	23.41	23.63	24.63	24.10	25.11	26.59
Nuclear Power	8.46	8.75	8.75	8.75	9.29	9.29	9.29	9.26	9.41	9.44
Biofuels Heat and Coproducts[7]	1.03	0.80	0.77	0.81	1.18	1.49	2.51	1.23	2.56	4.19
Renewable Energy[18]	5.70	7.91	8.37	8.36	8.99	9.27	9.03	9.52	9.63	9.54
Liquid Hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Electricity Imports	0.11	0.07	0.07	0.07	0.08	0.08	0.09	0.10	0.09	0.12
Total	**100.09**	**103.80**	**101.61**	**100.27**	**111.19**	**108.26**	**107.41**	**118.17**	**114.51**	**114.75**
Energy Use and Related Statistics										
Delivered Energy Use	72.59	75.45	73.30	72.11	80.43	77.78	77.44	85.76	82.33	83.15
Total Energy Use	100.09	103.80	101.61	100.27	111.19	108.26	107.41	118.17	114.51	114.75
Ethanol Consumed in Motor Gasoline and E85	0.82	1.31	1.23	1.32	1.53	1.56	2.59	1.55	2.35	3.46
Population (millions)	305.37	326.70	326.70	326.70	358.62	358.62	358.62	390.70	390.70	390.70
Gross Domestic Product (billion 2000 dollars)	11652	13429	13289	13161	17580	17561	17692	22358	22362	22570
Carbon Dioxide Emissions (million metric tons)	5814.4	5903.1	5730.7	5642.4	6277.8	6015.8	5829.1	6732.5	6320.4	6133.7

[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 electricity generation from wind and solar photovoltaic sources.
[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 electricity generation from wind and solar photovoltaic sources.
[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]The energy content of biofuels feedstock minus the energy content of liquid fuel produced.
[8]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.
[9]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.
[10]Includes only kerosene type.
[11]Diesel fuel for on- and off- road use.
[12]Includes aviation gasoline and lubricants.
[13]Includes unfinished oils, natural gasoline, motor gasoline blending components, aviation gasoline, lubricants, still gas, asphalt, road oil, petroleum coke, and miscellaneous petroleum products.
[14]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.
[15]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.
[16]Includes conventional hydroelectric, geothermal, wood and wood waste, biogenic municipal waste, other biomass, wind, photovoltaic, and solar thermal sources. Excludes net electricity imports.
[17]Includes non-biogenic municipal waste not included above.
[18]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 2008 are model results and may differ slightly from official EIA data reports.
Sources: 2008 consumption based on: Energy Information Administration (EIA), *Annual Energy Review 2008*, DOE/EIA-0384(2008) (Washington, DC, June 2009). 2008 population and gross domestic product: IHS Global Insight Industry and Employment models, August 2009. 2008 carbon dioxide emissions: EIA, *Emissions of Greenhouse Gases in the United States 2008,* DOE/EIA-0573(2008) (Washington, DC, December 2009). **Projections:** EIA, AEO2010 National Energy Modeling System runs LP2010.D011910A, AEO2010R.D111809A, and HP2010.D011910A.

Table C3. Energy Prices by Sector and Source
(2008 Dollars per Million Btu, Unless Otherwise Noted)

Sector and Source	2008	Projections								
		2015			2025			2035		
		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	29.35	20.16	28.03	38.45	19.98	31.55	48.94	20.22	34.65	51.29
Distillate Fuel Oil	24.47	12.95	21.08	30.32	13.88	25.23	38.94	14.83	28.66	41.94
Natural Gas	13.48	10.88	11.56	12.07	12.19	12.29	12.74	13.73	14.40	15.04
Electricity	33.29	30.32	31.43	32.40	31.46	32.26	33.15	33.68	34.71	35.70
Commercial										
Liquefied Petroleum Gases	26.15	16.94	24.77	35.18	16.72	28.26	45.63	16.94	31.32	47.95
Distillate Fuel Oil	21.50	11.14	18.72	27.43	11.78	22.72	36.27	12.40	26.13	39.23
Residual Fuel Oil	15.52	5.63	13.13	21.76	5.56	16.54	30.12	5.46	18.84	30.92
Natural Gas	11.94	9.35	9.99	10.49	10.59	10.70	11.12	12.01	12.66	13.26
Electricity	30.47	25.38	26.55	27.54	26.85	27.72	28.62	29.29	30.37	31.46
Industrial[1]										
Liquefied Petroleum Gases	24.20	14.84	22.49	32.95	14.48	26.12	43.42	14.53	29.25	45.76
Distillate Fuel Oil	22.31	11.75	19.00	27.56	12.24	22.97	36.56	12.82	26.48	39.55
Residual Fuel Oil	16.31	9.95	16.47	24.70	9.94	19.23	32.66	9.79	21.72	34.39
Natural Gas[2]	9.11	5.82	6.45	6.94	6.92	7.02	7.44	8.10	8.73	9.37
Metallurgical Coal	4.49	5.01	5.08	5.18	5.11	5.24	5.42	4.94	5.06	5.20
Other Industrial Coal	2.84	2.57	2.69	2.79	2.51	2.63	2.81	2.55	2.71	2.91
Coal to Liquids	- -	1.36	1.42	1.55	1.34	1.49	1.62	1.38	1.51	1.86
Electricity	20.21	16.66	17.37	18.01	18.05	18.50	18.97	20.10	20.71	21.34
Transportation										
Liquefied Petroleum Gases[3]	29.93	20.06	27.88	38.31	19.81	31.36	48.74	19.99	34.38	51.01
E85[4]	26.93	17.21	25.55	33.27	17.12	28.86	40.95	19.05	32.23	41.62
Motor Gasoline[5]	26.76	17.05	25.37	34.64	17.30	28.87	44.06	17.72	32.33	46.65
Jet Fuel[6]	22.71	10.92	19.04	28.36	11.67	22.92	36.58	12.84	26.48	39.49
Diesel Fuel (distillate fuel oil)[7]	27.65	15.74	22.93	31.48	15.80	26.63	40.44	16.02	29.96	43.24
Residual Fuel Oil	14.49	6.65	13.58	21.66	6.17	15.93	29.38	6.15	18.60	31.66
Natural Gas[8]	15.96	12.78	13.37	13.81	13.40	13.43	13.82	14.17	14.78	15.32
Electricity	33.73	27.95	28.79	29.47	28.50	28.63	30.96	31.17	33.26	35.87
Electric Power[9]										
Distillate Fuel Oil	19.37	9.39	17.36	26.38	10.26	21.35	34.75	11.09	24.70	37.65
Residual Fuel Oil	14.56	7.37	15.53	23.70	6.94	18.30	31.81	6.85	21.12	34.04
Natural Gas	9.09	5.49	6.08	6.51	6.69	6.75	7.09	7.82	8.46	8.98
Steam Coal	2.05	1.88	2.01	2.12	1.85	1.99	2.17	1.91	2.09	2.28
Average Price to All Users[10]										
Liquefied Petroleum Gases	20.19	13.22	20.30	29.55	13.11	23.34	39.17	13.48	26.37	41.50
E85[4]	26.93	17.21	25.55	33.27	17.12	28.86	40.95	19.05	32.23	41.62
Motor Gasoline[5]	26.54	17.05	25.36	34.63	17.30	28.87	44.06	17.72	32.32	46.65
Jet Fuel	22.71	10.92	19.04	28.36	11.67	22.92	36.58	12.84	26.48	39.49
Distillate Fuel Oil	26.27	14.70	22.03	30.65	15.01	25.89	39.66	15.45	29.34	42.59
Residual Fuel Oil	14.77	7.22	14.26	22.38	6.87	16.80	30.23	6.81	19.46	32.38
Natural Gas	10.53	7.45	8.14	8.66	8.63	8.75	9.21	9.81	10.54	11.21
Metallurgical Coal	4.49	5.01	5.08	5.18	5.11	5.24	5.42	4.94	5.06	5.20
Other Coal	2.10	1.92	2.05	2.16	1.89	2.02	2.20	1.94	2.12	2.31
Coal to Liquids	- -	1.36	1.42	1.55	1.34	1.49	1.62	1.38	1.51	1.86
Electricity	28.81	24.90	25.95	26.87	26.41	27.17	27.97	28.89	29.87	30.85
Non-Renewable Energy Expenditures by Sector (billion 2008 dollars)										
Residential	254.66	217.97	230.89	243.46	247.76	258.70	273.37	285.45	301.11	315.63
Commercial	191.19	167.41	176.90	185.72	201.61	210.07	221.52	248.04	261.07	274.49
Industrial	244.81	163.98	213.14	267.98	173.94	241.75	330.70	184.47	267.18	350.42
Transportation	705.86	456.29	655.77	882.66	503.13	782.71	1033.47	581.05	908.01	1123.59
Total Non-Renewable Expenditures	1396.52	1005.65	1276.69	1579.83	1126.44	1493.23	1859.07	1299.01	1737.37	2064.13
Transportation Renewable Expenditures	0.17	0.16	0.21	6.91	3.85	15.06	103.71	0.43	56.42	160.44
Total Expenditures	**1396.69**	**1005.81**	**1276.90**	**1586.74**	**1130.29**	**1508.29**	**1962.77**	**1299.44**	**1793.79**	**2224.57**

Table C3. Energy Prices by Sector and Source (Continued)
(Nominal Dollars per Million Btu, Unless Otherwise Noted)

Sector and Source	2008	Projections								
		2015			2025			2035		
		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	29.35	22.37	31.23	42.94	27.42	42.82	65.67	34.03	58.23	85.33
Distillate Fuel Oil	24.47	14.37	23.49	33.85	19.06	34.24	52.24	24.95	48.16	69.77
Natural Gas	13.48	12.07	12.88	13.48	16.73	16.68	17.09	23.11	24.20	25.01
Electricity	33.29	33.64	35.02	36.18	43.18	43.78	44.48	56.69	58.33	59.39
Commercial										
Liquefied Petroleum Gases	26.15	18.79	27.61	39.29	22.96	38.35	61.23	28.51	52.64	79.76
Distillate Fuel Oil	21.50	12.36	20.86	30.63	16.16	30.83	48.67	20.86	43.92	65.26
Residual Fuel Oil	15.52	6.24	14.63	24.30	7.63	22.45	40.41	9.19	31.66	51.44
Natural Gas	11.94	10.37	11.14	11.71	14.54	14.53	14.91	20.21	21.27	22.05
Electricity	30.47	28.16	29.58	30.75	36.85	37.62	38.40	49.31	51.04	52.33
Industrial[1]										
Liquefied Petroleum Gases	24.20	16.47	25.06	36.79	19.87	35.45	58.26	24.45	49.15	76.12
Distillate Fuel Oil	22.31	13.03	21.18	30.78	16.80	31.18	49.06	21.58	44.51	65.78
Residual Fuel Oil	16.31	11.04	18.35	27.58	13.64	26.10	43.82	16.48	36.50	57.21
Natural Gas[2]	9.11	6.46	7.18	7.75	9.50	9.52	9.98	13.63	14.67	15.59
Metallurgical Coal	4.49	5.56	5.66	5.78	7.01	7.11	7.27	8.31	8.50	8.66
Other Industrial Coal	2.84	2.85	3.00	3.12	3.45	3.56	3.78	4.28	4.55	4.84
Coal to Liquids	- -	1.51	1.58	1.73	1.84	2.02	2.18	2.33	2.53	3.09
Electricity	20.21	18.48	19.36	20.12	24.78	25.11	25.45	33.84	34.80	35.49
Transportation										
Liquefied Petroleum Gases[3]	29.93	22.25	31.07	42.78	27.20	42.56	65.40	33.64	57.77	84.85
E85[4]	26.93	19.09	28.47	37.15	23.50	39.17	54.95	32.06	54.17	69.23
Motor Gasoline[5]	26.76	18.92	28.27	38.68	23.75	39.18	59.12	29.82	54.33	77.61
Jet Fuel[6]	22.71	12.11	21.21	31.67	16.02	31.10	49.08	21.60	44.51	65.69
Diesel Fuel (distillate fuel oil)[7]	27.65	17.46	25.56	35.15	21.69	36.13	54.26	26.96	50.35	71.93
Residual Fuel Oil	14.49	7.38	15.13	24.19	8.46	21.63	39.42	10.36	31.26	52.66
Natural Gas[8]	15.96	14.17	14.90	15.42	18.40	18.23	18.54	23.85	24.84	25.49
Electricity	33.73	31.01	32.08	32.91	39.13	38.86	41.54	52.46	55.89	59.66
Electric Power[9]										
Distillate Fuel Oil	19.37	10.41	19.35	29.45	14.09	28.98	46.63	18.67	41.52	62.64
Residual Fuel Oil	14.56	8.17	17.30	26.46	9.52	24.83	42.68	11.53	35.49	56.63
Natural Gas	9.09	6.09	6.77	7.27	9.18	9.17	9.52	13.16	14.22	14.94
Steam Coal	2.05	2.09	2.24	2.37	2.55	2.69	2.91	3.21	3.51	3.79

Table C3. Energy Prices by Sector and Source (Continued)
(Nominal Dollars per Million Btu, Unless Otherwise Noted)

Sector and Source	2008	Projections								
		2015			2025			2035		
		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	20.19	14.67	22.62	33.00	18.00	31.68	52.56	22.68	44.32	69.03
E85[4]	26.93	19.09	28.47	37.15	23.50	39.17	54.95	32.06	54.17	69.23
Motor Gasoline[5]	26.54	18.91	28.27	38.68	23.74	39.17	59.12	29.82	54.32	77.61
Jet Fuel	22.71	12.11	21.21	31.67	16.02	31.10	49.08	21.60	44.51	65.69
Distillate Fuel Oil	26.27	16.31	24.55	34.22	20.61	35.14	53.22	26.01	49.31	70.85
Residual Fuel Oil	14.77	8.01	15.89	25.00	9.43	22.80	40.56	11.47	32.70	53.86
Natural Gas	10.53	8.27	9.07	9.67	11.85	11.88	12.35	16.51	17.71	18.65
Metallurgical Coal	4.49	5.56	5.66	5.78	7.01	7.11	7.27	8.31	8.50	8.66
Other Coal	2.10	2.13	2.28	2.41	2.59	2.74	2.96	3.27	3.56	3.84
Coal to Liquids	- -	1.51	1.58	1.73	1.84	2.02	2.18	2.33	2.53	3.09
Electricity	28.81	27.63	28.92	30.01	36.26	36.87	37.53	48.62	50.19	51.31
Non-Renewable Energy Expenditures by Sector (billion nominal dollars)										
Residential	254.66	241.83	257.29	271.88	340.11	351.09	366.81	480.43	506.03	525.04
Commercial	191.19	185.74	197.13	207.40	276.76	285.09	297.24	417.47	438.74	456.61
Industrial	244.81	181.93	237.51	299.26	238.77	328.09	443.73	310.48	449.00	582.92
Transportation	705.86	506.26	730.78	985.70	690.66	1062.24	1386.69	977.97	1525.95	1869.09
Total Non-Renewable Expenditures	1396.52	1115.76	1422.72	1764.24	1546.29	2026.51	2494.47	2186.36	2919.72	3433.66
Transportation Renewable Expenditures	0.17	0.17	0.24	7.72	5.28	20.44	139.15	0.72	94.81	266.90
Total Expenditures	**1396.69**	**1115.94**	**1422.95**	**1771.96**	**1551.57**	**2046.94**	**2633.62**	**2187.08**	**3014.53**	**3700.55**

[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 2008 are model results and may differ slightly from official EIA data reports.
Sources: 2008 prices for motor gasoline, distillate fuel oil, and jet fuel are based on prices in the Energy Information Administration (EIA), *Petroleum Marketing Annual 2008*, DOE/EIA-0487(2008) (Washington, DC, August 2009). 2008 residential and commercial natural gas delivered prices: EIA, *Natural Gas Monthly*, DOE/EIA-0130(2009/07) (Washington, DC, July 2009). 2008 industrial natural gas delivered prices are estimated based on: EIA, *Manufacturing Energy Consumption Survey* and industrial and wellhead prices from the *Natural Gas Annual 2007*, DOE/EIA-0131(2007) (Washington, DC, January 2009) and the *Natural Gas Monthly*, DOE/EIA-0130(2009/07) (Washington, DC, July 2009). 2008 transportation sector natural gas delivered prices are model results. 2008 electric power sector natural gas prices: EIA, *Electric Power Monthly*, DOE/EIA-0226, April 2008 and April 2009, Table 4.13.B. 2008 coal prices based on: EIA, *Quarterly Coal Report, October-December 2008*, DOE/EIA-0121(2008/4Q) (Washington, DC, March 2009) and EIA, AEO2010 National Energy Modeling System run AEO2010R.D111809A. 2008 electricity prices: EIA, *Annual Energy Review 2008*, DOE/EIA-0384(2008) (Washington, DC, June 2009). 2008 E85 prices derived from monthly prices in the Clean Cities Alternative Fuel Price Report.
Projections: EIA, AEO2010 National Energy Modeling System runs LP2010.D011910A, AEO2010R.D111809A, and HP2010.D011910A.

Table C4. Liquid Fuels Supply and Disposition
(Million Barrels per Day, Unless Otherwise Noted)

Supply and Disposition	2008	Projections								
		2015			2025			2035		
		Low Oil Price	Reference	High Oil Price	Low Oil Price	Reference	High Oil Price	Low Oil Price	Reference	High Oil Price
Crude Oil										
Domestic Crude Production[1]	4.96	5.56	5.77	5.84	4.95	6.13	6.81	4.37	6.27	6.89
Alaska	0.69	0.49	0.49	0.49	0.53	0.74	0.79	0.21	0.45	0.45
Lower 48 States	4.28	5.07	5.28	5.35	4.42	5.39	6.02	4.16	5.83	6.45
Net Imports	9.75	10.06	8.88	8.21	11.63	8.60	5.87	13.57	8.65	5.30
Gross Imports	9.78	10.09	8.91	8.24	11.66	8.63	5.91	13.59	8.68	5.33
Exports	0.03	0.03	0.03	0.03	0.03	0.03	0.04	0.02	0.03	0.04
Other Crude Supply[2]	-0.06	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total Crude Supply	**14.66**	**15.62**	**14.66**	**14.05**	**16.58**	**14.73**	**12.68**	**17.94**	**14.92**	**12.19**
Other Petroleum Supply	**4.10**	**4.16**	**4.05**	**3.86**	**4.35**	**4.01**	**3.28**	**4.74**	**3.98**	**3.20**
Natural Gas Plant Liquids	1.78	1.80	1.77	1.73	1.83	1.74	1.75	1.86	1.83	1.82
Net Product Imports	1.39	1.27	1.24	1.06	1.34	1.10	0.61	1.69	1.02	0.52
Gross Refined Product Imports[3]	1.54	1.11	1.23	1.17	1.18	1.25	0.99	1.39	1.22	1.03
Unfinished Oil Imports	0.76	0.93	0.81	0.74	1.05	0.82	0.57	1.22	0.85	0.52
Blending Component Imports	0.79	0.84	0.80	0.78	0.89	0.82	0.74	0.95	0.84	0.74
Exports	1.71	1.60	1.60	1.63	1.78	1.79	1.69	1.87	1.89	1.77
Refinery Processing Gain[4]	1.00	1.08	1.04	1.07	1.18	1.17	0.92	1.19	1.13	0.86
Product Stock Withdrawal	-0.07	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Other Non-petroleum Supply	**0.78**	**1.32**	**1.42**	**1.72**	**1.65**	**2.11**	**3.88**	**1.68**	**3.11**	**5.46**
Supply from Renewable Sources	0.71	1.11	1.10	1.19	1.40	1.63	2.55	1.42	2.58	3.64
Ethanol	0.65	1.01	0.95	1.02	1.19	1.21	2.00	1.20	1.82	2.68
Domestic Production	0.61	0.98	0.91	0.93	1.13	1.10	1.67	1.16	1.49	2.21
Net Imports	0.05	0.03	0.04	0.09	0.05	0.11	0.33	0.04	0.33	0.48
Biodiesel	0.05	0.07	0.11	0.11	0.08	0.11	0.14	0.05	0.13	0.15
Domestic Production	0.05	0.07	0.11	0.11	0.08	0.11	0.14	0.05	0.13	0.15
Net Imports	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Other Biomass-derived Liquids[5]	0.01	0.03	0.04	0.06	0.13	0.31	0.41	0.18	0.63	0.81
Liquids from Gas	0.00	0.00	0.00	0.00	0.00	0.00	0.21	0.00	0.00	0.50
Liquids from Coal	0.00	0.05	0.07	0.10	0.06	0.15	0.60	0.06	0.24	0.92
Other[6]	0.07	0.16	0.25	0.43	0.20	0.33	0.53	0.20	0.29	0.40
Total Primary Supply[7]	**19.54**	**21.10**	**20.13**	**19.63**	**22.58**	**20.86**	**19.85**	**24.36**	**22.00**	**20.85**
Liquid Fuels Consumption										
by Fuel										
Liquefied Petroleum Gases	1.95	2.08	2.15	2.38	2.04	2.33	2.33	1.97	2.19	2.19
E85[8]	0.00	0.01	0.01	0.14	0.15	0.36	1.74	0.02	1.20	2.65
Motor Gasoline[9]	8.99	9.98	9.37	9.06	10.64	9.32	7.29	11.81	9.06	6.86
Jet Fuel[10]	1.54	1.59	1.57	1.55	1.76	1.75	1.74	1.85	1.84	1.83
Distillate Fuel Oil[11]	3.94	4.23	4.08	3.98	4.61	4.41	4.30	5.25	4.91	4.80
Diesel	3.44	3.66	3.56	3.49	4.07	3.93	3.87	4.73	4.48	4.40
Residual Fuel Oil	0.62	0.79	0.66	0.64	0.84	0.66	0.65	0.89	0.67	0.67
Other[12]	2.47	2.51	2.35	2.01	2.65	2.17	1.86	2.76	2.18	1.82
by Sector										
Residential and Commercial	0.98	0.97	0.89	0.84	0.95	0.83	0.74	0.94	0.79	0.71
Industrial[13]	4.75	4.95	4.82	4.71	5.03	4.81	4.53	5.07	4.67	4.34
Transportation	13.88	14.96	14.27	14.02	16.37	15.14	14.43	18.15	16.38	15.54
Electric Power[14]	0.21	0.30	0.20	0.20	0.34	0.21	0.21	0.38	0.22	0.22
Total	**19.53**	**21.19**	**20.18**	**19.77**	**22.69**	**20.99**	**19.92**	**24.54**	**22.06**	**20.81**
Discrepancy[15]	**0.01**	**-0.08**	**-0.05**	**-0.14**	**-0.11**	**-0.13**	**-0.07**	**-0.19**	**-0.06**	**0.03**

Table C4. Liquid Fuels Supply and Disposition (Continued)
(Million Barrels per Day, Unless Otherwise Noted)

Supply and Disposition	2008	Projections								
		2015			2025			2035		
		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[16]	17.6	18.0	17.9	17.6	18.5	16.8	15.6	19.7	17.3	15.3
Capacity Utilization Rate (percent)[17]	85.0	88.4	83.7	81.2	91.6	89.5	83.3	93.0	88.3	81.3
Net Import Share of Product Supplied (percent)	57.3	53.9	50.5	47.7	57.7	47.1	34.3	62.8	45.4	30.2
Net Expenditures for Imported Crude Oil and Petroleum Products (billion 2008 dollars)	437.90	172.10	301.44	442.73	187.93	356.35	438.01	223.98	420.54	435.49

[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 pyrolysis oils, biomass-derived Fischer-Tropsch liquids, and renewable feedstocks used for the production of green diesel and gasoline.
[6]Includes domestic sources of other blending components, other hydrocarbons, and ethers.
[7]Total crude supply plus natural gas plant liquids, other inputs, refinery processing gain, and net product imports.
[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 fuel oil and kerosene from petroleum and biomass feedstocks.
[12]Includes aviation gasoline, petrochemical feedstocks, lubricants, waxes, asphalt, road oil, still gas, special naphthas, petroleum coke, crude oil product supplied, methanol, 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]End-of-year operable capacity.
[17]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 2008 are model results and may differ slightly from official EIA data reports.
Sources: 2008 petroleum product supplied based on: Energy Information Administration (EIA), *Annual Energy Review 2008*, DOE/EIA-0384(2008) (Washington, DC, June 2009). Other 2008 data: EIA, *Petroleum Supply Annual 2008,* DOE/EIA-0340(2008)/1 (Washington, DC, June 2009). **Projections:** EIA, AEO2010 National Energy Modeling System runs LP2010.D011910A, AEO2010R.D111809A, and HP2010.D011910A.

Table C5. Petroleum Product Prices
(2008 Cents per Gallon, Unless Otherwise Noted)

Sector and Fuel	2008	Projections								
		2015			2025			2035		
		Low Oil Price	Reference	High Oil Price	Low Oil Price	Reference	High Oil Price	Low Oil Price	Reference	High Oil Price
Crude Oil Prices (2008 dollars per barrel)										
Imported Low Sulfur Light Crude Oil[1]	99.57	51.59	94.52	144.78	51.73	115.09	196.01	51.44	133.22	209.60
Imported Crude Oil[1]	92.61	43.88	86.88	137.01	41.36	104.49	185.85	41.99	121.37	199.65
Delivered Sector Product Prices										
Residential										
Liquefied Petroleum Gases	251.5	172.8	240.2	329.6	171.2	270.4	419.5	173.3	297.0	439.6
Distillate Fuel Oil	339.3	179.6	292.4	420.5	192.6	349.9	540.0	205.6	397.5	581.7
Commercial										
Distillate Fuel Oil	296.8	153.6	258.0	378.2	162.4	313.2	500.1	170.9	360.3	540.9
Residual Fuel Oil	232.4	84.2	196.5	325.7	83.2	247.6	450.8	81.7	282.0	462.9
Residual Fuel Oil (2008 dollars per barrel)	97.61	35.38	82.52	136.79	34.96	104.01	189.33	34.32	118.45	194.40
Industrial[2]										
Liquefied Petroleum Gases	207.4	127.2	192.7	282.4	124.1	223.9	372.1	124.5	250.6	392.2
Distillate Fuel Oil	307.4	161.3	260.9	378.4	168.0	315.4	501.9	176.0	363.6	542.9
Residual Fuel Oil	244.1	149.0	246.5	369.7	148.8	287.9	488.9	146.6	325.1	514.8
Residual Fuel Oil (2008 dollars per barrel)	102.52	62.59	103.52	155.27	62.48	120.91	205.34	61.56	136.54	216.23
Transportation										
Liquefied Petroleum Gases	256.5	171.9	238.9	328.4	169.8	268.8	417.7	171.3	294.6	437.2
Ethanol (E85)[3]	255.5	163.3	242.4	315.6	162.4	273.8	388.5	180.7	305.8	394.8
Ethanol Wholesale Price	244.6	210.8	198.9	230.7	171.8	188.6	276.5	173.4	211.5	248.1
Motor Gasoline[4]	326.7	206.3	306.9	419.1	209.3	349.3	533.1	214.4	391.1	564.5
Jet Fuel[5]	306.5	147.4	257.0	382.9	157.5	309.4	493.8	173.3	357.5	533.1
Diesel Fuel (distillate fuel oil)[6]	379.3	215.7	314.3	431.4	216.5	364.9	554.1	219.5	410.5	592.5
Residual Fuel Oil	216.9	99.6	203.3	324.3	92.3	238.5	439.8	92.1	278.5	473.9
Residual Fuel Oil (2008 dollars per barrel)	91.11	41.81	85.37	136.20	38.76	100.18	184.72	38.70	116.95	199.04
Electric Power[7]										
Distillate Fuel Oil	268.6	130.2	240.8	365.8	142.3	296.1	481.9	153.8	342.6	522.2
Residual Fuel Oil	218.0	110.3	232.4	354.7	103.8	273.9	476.1	102.5	316.1	509.6
Residual Fuel Oil (2008 dollars per barrel)	91.57	46.32	97.61	148.98	43.61	115.04	199.98	43.06	132.75	214.01
Refined Petroleum Product Prices[8]										
Liquefied Petroleum Gases	173.0	113.3	174.0	253.3	112.4	200.1	335.7	115.5	226.0	355.6
Motor Gasoline[4]	324.0	206.3	306.9	419.0	209.3	349.3	533.1	214.4	391.1	564.5
Jet Fuel[5]	306.5	147.4	257.0	382.9	157.5	309.4	493.8	173.3	357.5	533.1
Distillate Fuel Oil	361.2	201.8	302.3	420.5	206.0	355.2	544.2	212.0	402.5	584.2
Residual Fuel Oil	221.1	108.0	213.4	335.0	102.9	251.4	452.5	102.0	291.3	484.7
Residual Fuel Oil (2008 dollars per barrel)	92.85	45.38	89.64	140.72	43.21	105.61	190.05	42.84	122.34	203.56
Average	**304.7**	**183.3**	**279.6**	**389.0**	**187.1**	**322.9**	**499.0**	**194.3**	**366.2**	**534.1**

Table C5. Petroleum Product Prices (Continued)
(Nominal Cents per Gallon, Unless Otherwise Noted)

Sector and Fuel	2008	Projections								
		2015			2025			2035		
		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]	99.57	57.24	105.33	161.68	71.01	156.20	263.01	86.58	223.88	348.67
Imported Crude Oil[1]	92.61	48.68	96.82	153.00	56.78	141.80	249.37	70.68	203.97	332.11
Delivered Sector Product Prices										
Residential										
Liquefied Petroleum Gases	251.5	191.7	267.7	368.0	235.0	367.0	562.8	291.7	499.1	731.3
Distillate Fuel Oil	339.3	199.2	325.8	469.5	264.3	474.9	724.6	346.1	667.9	967.6
Commercial										
Distillate Fuel Oil	296.8	170.4	287.6	422.4	222.9	425.1	671.0	287.7	605.5	899.8
Residual Fuel Oil	232.4	93.5	219.0	363.7	114.3	336.1	604.9	137.5	474.0	770.0
Industrial[2]										
Liquefied Petroleum Gases	207.4	141.1	214.8	315.3	170.3	303.9	499.3	209.6	421.2	652.4
Distillate Fuel Oil	307.4	178.9	290.7	422.6	230.7	428.0	673.4	296.3	611.0	903.1
Residual Fuel Oil	244.1	165.3	274.7	412.8	204.2	390.7	656.0	246.7	546.4	856.4
Transportation										
Liquefied Petroleum Gases	256.5	190.7	266.3	366.7	233.1	364.8	560.5	288.3	495.1	727.2
Ethanol (E85)[3]	255.5	181.2	270.1	352.4	223.0	371.6	521.3	304.1	513.9	656.8
Ethanol Wholesale Price	244.6	233.9	221.6	257.6	235.8	256.0	371.0	291.9	355.4	412.8
Motor Gasoline[4]	326.7	228.9	342.1	468.0	287.3	474.0	715.3	360.9	657.3	939.0
Jet Fuel[5]	306.5	163.5	286.4	427.6	216.2	419.9	662.6	291.7	600.8	886.9
Diesel Fuel (distillate fuel oil)[6]	379.3	239.3	350.2	481.7	297.2	495.2	743.5	369.5	689.9	985.6
Residual Fuel Oil	216.9	110.5	226.5	362.1	126.7	323.7	590.1	155.1	468.0	788.3
Electric Power[7]										
Distillate Fuel Oil	268.6	144.4	268.4	408.5	195.4	401.9	646.7	258.9	575.8	868.7
Residual Fuel Oil	218.0	122.4	259.0	396.1	142.5	371.7	638.9	172.5	531.2	847.6
Refined Petroleum Product Prices[8]										
Liquefied Petroleum Gases	173.0	125.7	193.9	282.8	154.2	271.5	450.4	194.4	379.8	591.6
Motor Gasoline[4]	324.0	228.8	342.0	467.9	287.3	474.0	715.3	360.8	657.2	939.0
Jet Fuel[5]	306.5	163.5	286.4	427.6	216.2	419.9	662.6	291.7	600.8	886.9
Distillate Fuel Oil	361.2	223.9	336.9	469.6	282.8	482.1	730.1	356.8	676.4	971.8
Residual Fuel Oil (nominal dollars per barrel)	92.85	50.35	99.90	157.15	59.31	143.32	255.01	72.11	205.59	338.61
Average	**304.7**	**203.4**	**311.5**	**434.4**	**256.8**	**438.2**	**669.6**	**327.1**	**615.4**	**888.4**

[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 2008 are model results and may differ slightly from official EIA data reports.
Sources: 2008 imported low sulfur light crude oil price: Energy Information Administration (EIA), Form EIA-856, "Monthly Foreign Crude Oil Acquisition Report." 2008 imported crude oil price: EIA, *Annual Energy Review 2008*, DOE/EIA-0384(2008) (Washington, DC, June 2009). 2008 prices for motor gasoline, distillate fuel oil, and jet fuel are based on: EIA, *Petroleum Marketing Annual 2008*, DOE/EIA-0487(2008) (Washington, DC, August 2009). 2008 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." 2008 electric power prices based on: Federal Energy Regulatory Commission, FERC Form 423, "Monthly Report of Cost and Quality of Fuels for Electric Plants." 2008 E85 prices derived from monthly prices in the Clean Cities Alternative Fuel Price Report. 2008 wholesale ethanol prices derived from Bloomberg U.S. average rack price. **Projections:** EIA, AEO2010 National Energy Modeling System runs LP2010.D011910A, AEO2010R.D111809A, and HP2010.D011910A.

Table C6. International Liquids Supply and Disposition Summary
(Million Barrels per Day, Unless Otherwise Noted)

Supply and Disposition	2008	Projections								
		2015			2025			2035		
		Low Oil Price	Reference	High Oil Price	Low Oil Price	Reference	High Oil Price	Low Oil Price	Reference	High Oil Price
Crude Oil Prices (2008 dollars per barrel)[1]										
Imported Low Sulfur Light Crude Oil Price	99.57	51.59	94.52	144.78	51.73	115.09	196.01	51.44	133.22	209.60
Imported Crude Oil Price	92.61	43.88	86.88	137.01	41.36	104.49	185.85	41.99	121.37	199.65
Crude Oil Prices (nominal dollars per barrel)[1]										
Imported Low Sulfur Light Crude Oil Price	99.57	57.24	105.33	161.68	71.01	156.20	263.01	86.58	223.88	348.67
Imported Crude Oil Price	92.61	48.68	96.82	153.00	56.78	141.80	249.37	70.68	203.97	332.11
Conventional Production (Conventional)[2]										
OPEC[3]										
Middle East	24.24	29.83	25.42	22.58	35.75	27.87	22.05	41.31	30.94	21.38
North Africa	4.06	5.17	4.42	3.96	5.48	4.32	3.43	5.96	4.53	3.15
West Africa	4.18	6.32	5.30	4.71	7.68	5.87	4.55	8.74	6.43	4.29
South America	2.50	2.49	2.14	1.92	3.30	2.60	2.06	3.62	2.75	1.92
Total OPEC	**34.98**	**43.81**	**37.28**	**33.17**	**52.21**	**40.65**	**32.09**	**59.63**	**44.64**	**30.74**
Non-OPEC										
OECD										
United States (50 states)	7.68	8.61	8.83	9.07	8.16	9.32	9.96	7.62	9.14	9.60
Canada	1.84	1.51	1.52	1.60	1.07	1.10	1.07	0.98	1.02	0.97
Mexico	3.19	2.11	2.12	1.43	2.03	1.88	1.05	2.75	2.21	1.28
OECD Europe[4]	4.96	3.67	3.66	3.93	2.85	2.95	2.88	2.76	2.96	2.77
Japan	0.13	0.16	0.14	0.12	0.19	0.16	0.13	0.21	0.17	0.13
Australia and New Zealand	0.65	0.57	0.57	0.62	0.51	0.54	0.54	0.51	0.57	0.54
Total OECD	**18.46**	**16.62**	**16.83**	**16.78**	**14.80**	**15.96**	**15.63**	**14.83**	**16.08**	**15.29**
Non-OECD										
Russia	9.79	9.65	9.71	6.37	12.58	11.63	6.12	15.97	12.68	7.05
Other Europe and Eurasia[5]	2.88	4.19	4.22	2.91	4.90	4.63	2.62	6.34	5.27	3.10
China	3.97	3.61	3.62	4.01	3.03	3.27	3.28	2.84	3.27	3.13
Other Asia[6]	3.76	3.63	3.66	4.01	3.32	3.56	3.57	3.09	3.49	3.37
Middle East	1.54	1.61	1.63	1.81	1.19	1.30	1.32	1.11	1.31	1.28
Africa	2.39	2.47	2.49	2.79	2.39	2.63	2.68	2.38	2.84	2.78
Brazil	1.95	3.07	3.08	1.99	4.82	4.44	2.28	6.57	5.18	2.82
Other Central and South America	1.82	1.67	1.68	1.85	1.69	1.82	1.83	1.97	2.28	2.21
Total Non-OECD	**28.09**	**29.90**	**30.09**	**25.75**	**33.92**	**33.28**	**23.69**	**40.27**	**36.32**	**25.72**
Total Conventional Production	**81.53**	**90.33**	**84.21**	**75.70**	**100.94**	**89.89**	**71.41**	**114.73**	**97.05**	**71.76**
Unconventional Production[7]										
United States (50 states)	0.66	1.13	1.14	1.20	1.40	1.72	3.07	1.44	2.86	4.96
Other North America	1.53	2.31	2.88	2.91	3.56	4.10	4.72	4.10	4.84	5.93
OECD Europe[3]	0.25	0.27	0.40	0.50	0.41	0.56	0.71	0.48	0.64	0.73
Middle East	0.00	0.08	0.10	0.09	0.17	0.21	0.17	0.17	0.23	0.19
Africa.	0.23	0.20	0.35	0.38	0.29	0.57	0.62	0.35	0.70	0.74
Central and South America	1.09	1.82	1.48	1.43	3.23	2.41	2.40	4.70	3.10	2.86
Other	0.23	0.24	0.36	0.44	0.75	1.23	1.71	1.27	2.28	3.74
Total Unconventional Production	**3.98**	**6.05**	**6.71**	**6.94**	**9.80**	**10.79**	**13.41**	**12.52**	**14.65**	**19.16**
Total Production	**85.51**	**96.38**	**90.92**	**82.64**	**110.74**	**100.68**	**84.82**	**127.25**	**111.69**	**90.92**

Table C6. International Liquids Supply and Disposition Summary (Continued)
(Million Barrels per Day, Unless Otherwise Noted)

Supply and Disposition	2008	Projections								
		2015			2025			2035		
		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)	19.53	21.19	20.18	19.77	22.69	20.99	19.92	24.54	22.06	20.81
United States Territories	0.40	0.50	0.49	0.48	0.59	0.57	0.56	0.65	0.62	0.60
Canada	2.40	2.49	2.34	2.06	2.71	2.45	1.98	3.01	2.65	2.05
Mexico	1.61	1.75	1.65	1.47	2.08	1.88	1.51	2.32	2.02	1.53
OECD Europe[3]	15.30	15.29	14.36	12.73	16.02	14.58	11.89	16.44	14.59	11.48
Japan	4.90	5.15	4.88	4.40	5.27	4.85	4.01	5.11	4.59	3.65
South Korea	2.83	2.95	2.75	2.41	2.92	2.63	2.13	3.03	2.67	2.12
Australia and New Zealand	1.05	1.17	1.10	0.97	1.37	1.24	1.01	1.55	1.37	1.08
Total OECD	**48.03**	**50.49**	**47.75**	**44.28**	**53.65**	**49.20**	**43.00**	**56.64**	**50.55**	**43.32**
Non-OECD										
Russia	2.71	2.88	2.70	2.39	2.98	2.70	2.21	3.02	2.64	2.11
Other Europe and Eurasia[5]	2.39	2.50	2.34	2.06	2.67	2.41	1.93	2.97	2.59	1.98
China	8.00	11.14	10.42	9.19	15.74	14.21	11.72	19.83	17.50	14.17
India	2.37	3.25	3.06	2.73	4.59	4.18	3.45	5.65	5.00	4.00
Other Asia	6.73	7.70	7.19	6.35	9.53	8.50	6.91	12.32	10.40	8.20
Middle East	6.61	7.92	7.62	6.89	10.00	9.01	7.08	13.36	11.23	7.92
Africa	3.24	3.79	3.53	3.10	4.15	3.70	2.97	4.56	3.89	3.02
Brazil	2.38	3.03	2.86	2.61	3.81	3.49	2.95	4.99	4.45	3.61
Other Central and South America	3.57	3.69	3.45	3.03	3.63	3.28	2.60	3.91	3.44	2.58
Total Non-OECD	**38.00**	**45.90**	**43.17**	**38.36**	**57.09**	**51.48**	**41.82**	**70.60**	**61.14**	**47.60**
Total Consumption	**86.03**	**96.39**	**90.92**	**82.64**	**110.74**	**100.68**	**84.82**	**127.24**	**111.69**	**90.91**
OPEC Production[9]	35.63	45.21	38.11	33.74	54.60	41.91	32.90	63.22	46.26	31.84
Non-OPEC Production[9]	49.88	51.17	52.80	48.90	56.14	58.77	51.92	64.03	65.43	59.07
Net Eurasia Exports	9.52	11.52	11.96	6.82	16.65	15.58	6.86	22.89	17.90	8.87
OPEC Market Share (percent)	41.7	46.9	41.9	40.8	49.3	41.6	38.8	49.7	41.4	35.0

[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 2008 are model results and may differ slightly from official EIA data reports.
Sources: 2008 low sulfur light crude oil price: Energy Information Administration (EIA), Form EIA-856, "Monthly Foreign Crude Oil Acquisition Report." 2008 imported crude oil price: EIA, *Annual Energy Review 2008*, DOE/EIA-0384(2008) (Washington, DC, June 2009). **2008 quantities and projections:** EIA, AEO2010 National Energy Modeling System runs LP2010.D011910A, AEO2010R.D111809A, and HP2010.D011910A and EIA, Generate World Oil Balance Model.

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Results from Side Cases

Table D1. Key Results for Residential and Commercial Sector Technology Cases

Energy Consumption	2008	2015				2025			
		2009 Technology	Reference	High Technology	Best Available Technology	2009 Technology	Reference	High Technology	Best Available Technology
Residential									
Energy Consumption (quadrillion Btu)									
Liquefied Petroleum Gases	0.45	0.42	0.41	0.39	0.38	0.42	0.40	0.36	0.35
Kerosene	0.04	0.04	0.04	0.04	0.03	0.04	0.03	0.03	0.03
Distillate Fuel Oil	0.68	0.60	0.59	0.58	0.55	0.52	0.49	0.45	0.41
Liquid Fuels and Other Petroleum	1.18	1.06	1.04	1.00	0.96	0.98	0.92	0.84	0.78
Natural Gas	5.01	4.91	4.85	4.40	4.07	5.29	5.04	4.12	3.58
Coal	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Renewable Energy[1]	0.45	0.41	0.40	0.39	0.38	0.46	0.42	0.39	0.36
Electricity	4.71	4.86	4.78	4.39	4.10	5.50	5.30	4.64	4.14
Delivered Energy	**11.34**	**11.25**	**11.07**	**10.19**	**9.51**	**12.24**	**11.69**	**9.99**	**8.86**
Electricity Related Losses	10.20	10.43	10.24	9.40	8.79	11.50	11.08	9.69	8.64
Total	**21.54**	**21.68**	**21.31**	**19.59**	**18.30**	**23.74**	**22.76**	**19.68**	**17.50**
Delivered Energy Intensity (million Btu per household)	**100.1**	**92.7**	**91.2**	**84.0**	**78.4**	**90.5**	**86.4**	**73.9**	**65.5**
Nonmarketed Renewables Consumption (quadrillion Btu)	**0.01**	**0.06**	**0.07**	**0.10**	**0.11**	**0.08**	**0.09**	**0.14**	**0.16**
Commercial									
Energy Consumption (quadrillion Btu)									
Liquefied Petroleum Gases	0.08	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09
Motor Gasoline[2]	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06
Kerosene	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Distillate Fuel Oil	0.36	0.31	0.31	0.30	0.30	0.28	0.28	0.27	0.27
Residual Fuel Oil	0.07	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09
Liquid Fuels and Other Petroleum	0.58	0.55	0.55	0.55	0.54	0.53	0.53	0.52	0.52
Natural Gas	3.21	3.33	3.32	3.18	3.18	3.57	3.55	3.30	3.32
Coal	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07
Renewable Energy[3]	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10
Electricity	4.61	5.13	5.00	4.74	4.53	6.09	5.76	5.10	4.62
Delivered Energy	**8.58**	**9.18**	**9.04**	**8.64**	**8.43**	**10.36**	**10.00**	**9.09**	**8.63**
Electricity Related Losses	10.00	10.99	10.72	10.17	9.71	12.74	12.03	10.66	9.66
Total	**18.58**	**20.17**	**19.77**	**18.81**	**18.14**	**23.10**	**22.03**	**19.75**	**18.29**
Delivered Energy Intensity (thousand Btu per square foot)	**108.9**	**107.9**	**106.3**	**101.6**	**99.1**	**106.3**	**102.6**	**93.2**	**88.5**
Commercial Sector Generation									
Net Summer Generation Capacity (megawatts)									
Natural Gas	666	805	841	893	914	1334	1893	2601	2739
Solar Photovoltaic	707	1327	1340	1372	1422	1642	1836	2180	2704
Wind	78	135	153	444	567	245	316	1265	1875
Electricity Generation (billion kilowatthours)									
Natural Gas	4.79	5.80	6.07	6.44	6.60	9.61	13.72	18.87	19.87
Solar Photovoltaic	1.12	2.12	2.15	2.20	2.28	2.62	2.98	3.55	4.41
Wind	0.10	0.18	0.21	0.61	0.78	0.34	0.44	1.77	2.59
Nonmarketed Renewables Consumption (quadrillion Btu)	**0.03**	**0.04**	**0.04**	**0.06**	**0.06**	**0.04**	**0.04**	**0.09**	**0.09**

[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 2008 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, AEO2010 National Energy Modeling System, runs BLDFRZN.D012010A, AEO2010R.D111809A, BLDHIGH.D012010C, and BLDBEST.D012010A.

2035				Annual Growth 2008-2035 (percent)			
2009 Technology	Reference	High Technology	Best Available Technology	2009 Technology	Reference	High Technology	Best Available Technology
0.43	0.40	0.36	0.35	-0.2%	-0.4%	-0.8%	-0.9%
0.04	0.03	0.03	0.02	-0.6%	-1.0%	-1.5%	-2.2%
0.46	0.41	0.37	0.31	-1.4%	-1.9%	-2.3%	-2.9%
0.92	0.85	0.75	0.68	-0.9%	-1.2%	-1.6%	-2.0%
5.43	5.01	3.94	3.38	0.3%	0.0%	-0.9%	-1.4%
0.01	0.01	0.00	0.00	-0.8%	-1.3%	-1.7%	-1.9%
0.49	0.43	0.38	0.33	0.4%	-0.1%	-0.6%	-1.1%
6.15	5.83	5.05	4.43	1.0%	0.8%	0.3%	-0.2%
13.00	**12.12**	**10.13**	**8.84**	**0.5%**	**0.2%**	**-0.4%**	**-0.9%**
12.44	11.79	10.21	8.97	0.7%	0.5%	0.0%	-0.5%
25.44	**23.92**	**20.34**	**17.81**	**0.6%**	**0.4%**	**-0.2%**	**-0.7%**
88.6	**82.6**	**69.0**	**60.2**	**-0.5%**	**-0.7%**	**-1.4%**	**-1.9%**
0.08	**0.11**	**0.17**	**0.22**	**9.4%**	**10.4%**	**12.1%**	**13.2%**
0.09	0.09	0.09	0.09	0.5%	0.5%	0.5%	0.5%
0.06	0.06	0.06	0.06	0.2%	0.2%	0.2%	0.2%
0.01	0.01	0.01	0.01	1.7%	1.7%	1.7%	1.7%
0.26	0.26	0.25	0.25	-1.2%	-1.2%	-1.4%	-1.4%
0.09	0.09	0.09	0.09	0.7%	0.7%	0.7%	0.7%
0.52	0.52	0.51	0.50	-0.4%	-0.4%	-0.5%	-0.5%
3.74	3.79	3.52	3.57	0.6%	0.6%	0.3%	0.4%
0.07	0.07	0.07	0.07	0.0%	0.0%	0.0%	0.0%
0.10	0.10	0.10	0.10	0.0%	0.0%	0.0%	0.0%
7.13	6.55	5.46	4.86	1.6%	1.3%	0.6%	0.2%
11.56	**11.04**	**9.66**	**9.10**	**1.1%**	**0.9%**	**0.4%**	**0.2%**
14.43	13.27	11.04	9.83	1.4%	1.1%	0.4%	-0.1%
25.99	**24.30**	**20.70**	**18.93**	**1.3%**	**1.0%**	**0.4%**	**0.1%**
104.6	**99.8**	**87.4**	**82.3**	**-0.1%**	**-0.3%**	**-0.8%**	**-1.0%**
2466	5022	7435	8080	5.0%	7.8%	9.3%	9.7%
2137	3624	5066	8084	4.2%	6.2%	7.6%	9.4%
431	595	2727	3939	6.5%	7.8%	14.0%	15.6%
17.75	36.48	54.04	58.73	5.0%	7.8%	9.4%	9.7%
3.40	5.99	8.41	13.40	4.2%	6.4%	7.8%	9.6%
0.62	0.85	3.80	5.40	7.0%	8.3%	14.4%	15.9%
0.04	**0.05**	**0.13**	**0.15**	**1.4%**	**2.3%**	**5.8%**	**6.4%**

Table D2. Key Results for Industrial Sector Technology Cases

Consumption and Indicators	2008	2015			2025			2035		
		2010 Technology	Reference	High Technology	2010 Technology	Reference	High Technology	2010 Technology	Reference	High Technology
Value of Shipments (billion 2000 dollars)										
Manufacturing	4014	4497	4497	4497	5324	5324	5324	6010	6010	6010
Nonmanufacturing	1394	1547	1547	1547	1673	1673	1673	1776	1776	1776
Total	**5408**	**6044**	**6044**	**6044**	**6997**	**6997**	**6997**	**7786**	**7786**	**7786**
Energy Consumption excluding Refining[1] (quadrillion Btu)										
Liquefied Petroleum Gases	2.13	2.39	2.28	2.26	2.66	2.53	2.44	2.47	2.32	2.19
Heat and Power	0.29	0.29	0.28	0.27	0.30	0.27	0.26	0.30	0.27	0.24
Feedstocks	1.85	2.10	2.01	1.99	2.37	2.25	2.18	2.17	2.06	1.95
Motor Gasoline	0.30	0.31	0.30	0.29	0.33	0.30	0.27	0.36	0.30	0.26
Distillate Fuel Oil	1.19	1.24	1.19	1.15	1.31	1.17	1.06	1.39	1.17	1.01
Residual Fuel Oil	0.17	0.15	0.14	0.14	0.15	0.14	0.13	0.16	0.13	0.12
Petrochemical Feedstocks	1.12	1.13	1.09	1.08	0.86	0.82	0.80	0.86	0.81	0.78
Petroleum Coke	0.25	0.23	0.21	0.20	0.25	0.20	0.18	0.26	0.19	0.16
Asphalt and Road Oil	1.01	1.16	1.08	1.02	1.25	1.02	0.87	1.30	0.96	0.77
Miscellaneous Petroleum[2]	0.45	0.38	0.36	0.35	0.38	0.34	0.31	0.37	0.32	0.29
Petroleum Subtotal	6.62	6.99	6.65	6.48	7.21	6.52	6.06	7.17	6.22	5.58
Natural Gas Heat and Power	5.00	5.48	5.12	5.04	6.02	5.11	4.91	6.12	4.92	4.67
Natural Gas Feedstocks	0.57	0.57	0.55	0.54	0.55	0.52	0.50	0.47	0.45	0.41
Lease and Plant Fuel[3]	1.32	1.11	1.11	1.11	1.23	1.23	1.23	1.29	1.29	1.29
Natural Gas Subtotal	6.89	7.16	6.78	6.69	7.80	6.86	6.63	7.87	6.65	6.37
Metallurgical Coal and Coke[4]	0.62	0.56	0.53	0.49	0.57	0.51	0.43	0.43	0.36	0.29
Other Industrial Coal	1.10	1.04	1.02	1.00	1.08	1.01	0.97	1.07	0.98	0.93
Coal Subtotal	1.72	1.59	1.55	1.49	1.65	1.52	1.40	1.50	1.34	1.22
Renewables[5]	1.50	1.58	1.59	1.61	1.70	1.74	1.82	1.74	1.83	1.99
Purchased Electricity	3.19	3.33	3.24	3.17	3.58	3.31	3.14	3.69	3.28	3.02
Delivered Energy	**19.93**	**20.67**	**19.82**	**19.45**	**21.93**	**19.96**	**19.05**	**21.97**	**19.33**	**18.18**
Electricity Related Losses	6.91	7.15	6.94	6.80	7.47	6.92	6.56	7.46	6.63	6.12
Total	**26.83**	**27.81**	**26.76**	**26.26**	**29.40**	**26.88**	**25.62**	**29.43**	**25.96**	**24.30**
Delivered Energy Use per Dollar of Shipments (thousand Btu per 2000 dollar)	**3.68**	**3.42**	**3.28**	**3.22**	**3.13**	**2.85**	**2.72**	**2.82**	**2.48**	**2.33**
Onsite Industrial Combined Heat and Power										
Capacity (gigawatts)	20.82	24.23	24.32	24.91	26.56	27.20	28.88	28.05	29.53	32.41
Generation (billion kilowatthours)	106.61	130.81	131.43	135.36	147.52	152.02	163.04	158.63	169.04	187.91

[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 2008 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, AEO2010 National Energy Modeling System runs INDFRZN.D012510A, AEO2010R.D111809A, and INDHIGH.D012510A.

Table D3. Key Results for Transportation Sector Technology Cases

Consumption and Indicators	2008	2015			2025			2035		
		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	2676	2915	2916	2918	3548	3554	3562	4171	4203	4244
Commercial Light Trucks[1]	70	77	78	78	92	92	92	105	105	105
Freight Trucks greater than 10,000	227	248	248	248	304	304	304	363	363	363
(billion seat miles available)										
Air	1030	1163	1163	1163	1341	1341	1341	1470	1470	1470
(billion ton miles traveled)										
Rail	1806	1881	1881	1881	2108	2108	2108	2257	2257	2257
Domestic Shipping	576	587	587	587	643	643	643	691	691	691
Energy Efficiency Indicators										
(miles per gallon)										
Tested New Light-Duty Vehicle[2]	27.6	30.0	30.8	31.2	35.1	35.9	37.1	37.0	38.8	40.4
New Car[2]	32.2	34.9	35.8	36.4	39.5	40.2	41.8	41.3	43.0	45.1
New Light Truck[2]	23.7	25.4	26.2	26.6	29.1	30.3	31.3	30.1	32.5	34.1
Light-Duty Stock[3]	20.9	22.2	22.3	22.4	25.9	26.2	26.7	28.4	29.3	30.3
New Commercial Light Truck[1]	15.2	15.9	16.3	16.4	17.6	18.2	18.7	17.8	19.1	19.8
Stock Commercial Light Truck[1]	14.3	15.1	15.1	15.2	17.0	17.2	17.4	17.7	18.5	19.1
Freight Truck	6.0	6.2	6.3	6.4	6.5	6.8	7.1	6.7	7.0	7.4
(seat miles per gallon)										
Aircraft	61.8	62.9	63.0	63.2	65.0	65.9	67.0	67.7	69.8	72.2
(ton miles per thousand Btu)										
Rail	3.1	3.1	3.2	3.2	3.1	3.2	3.3	3.1	3.2	3.3
Domestic Shipping	2.0	2.0	2.0	2.0	2.0	2.0	2.1	2.0	2.1	2.1
Energy Use (quadrillion Btu)										
by Mode										
Light-Duty Vehicles	16.06	16.35	16.27	16.16	16.96	16.75	16.51	18.16	17.73	17.32
Commercial Light Trucks[1]	0.61	0.64	0.64	0.64	0.68	0.67	0.66	0.74	0.71	0.69
Bus Transportation	0.26	0.28	0.28	0.28	0.31	0.31	0.31	0.35	0.35	0.35
Freight Trucks	4.72	5.04	4.93	4.82	5.84	5.58	5.33	6.78	6.46	6.14
Rail, Passenger	0.05	0.05	0.05	0.05	0.06	0.06	0.06	0.06	0.06	0.06
Rail, Freight	0.58	0.60	0.60	0.59	0.67	0.66	0.65	0.72	0.70	0.68
Shipping, Domestic	0.29	0.30	0.30	0.29	0.33	0.32	0.31	0.35	0.33	0.32
Shipping, International	0.90	0.91	0.91	0.90	0.92	0.92	0.91	0.94	0.93	0.92
Recreational Boats	0.25	0.26	0.26	0.26	0.28	0.28	0.28	0.29	0.29	0.29
Air	2.64	2.79	2.78	2.77	3.16	3.12	3.07	3.38	3.28	3.17
Military Use	0.71	0.66	0.66	0.66	0.69	0.69	0.69	0.72	0.72	0.72
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	0.61	0.61	0.61	0.72	0.72	0.72	0.74	0.74	0.74
Total	**27.85**	**28.63**	**28.42**	**28.19**	**30.76**	**30.21**	**29.64**	**33.39**	**32.46**	**31.56**
by Fuel										
Liquefied Petroleum Gases	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.03	0.03	0.03
E85[4]	0.01	0.01	0.01	0.01	0.53	0.52	0.51	1.74	1.75	1.72
Motor Gasoline[5]	16.76	17.10	17.02	16.91	17.11	16.91	16.71	16.83	16.44	16.19
Jet Fuel[6]	3.15	3.26	3.26	3.25	3.66	3.62	3.56	3.90	3.80	3.69
Distillate Fuel Oil[7]	6.09	6.43	6.32	6.21	7.42	7.13	6.83	8.71	8.28	7.78
Residual Fuel Oil	0.93	0.94	0.94	0.94	0.96	0.96	0.95	0.98	0.97	0.96
Other Petroleum[8]	0.17	0.17	0.17	0.17	0.18	0.18	0.18	0.19	0.19	0.19
Liquid Fuels and Other Petroleum	27.14	27.93	27.73	27.50	29.89	29.34	28.76	32.38	31.47	30.56
Pipeline Fuel Natural Gas	0.64	0.61	0.61	0.61	0.72	0.72	0.72	0.74	0.74	0.74
Compressed Natural Gas	0.04	0.06	0.05	0.05	0.12	0.11	0.12	0.22	0.19	0.19
Liquid Hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Electricity	0.02	0.03	0.03	0.03	0.03	0.04	0.04	0.04	0.06	0.06
Delivered Energy	**27.85**	**28.63**	**28.42**	**28.19**	**30.76**	**30.21**	**29.64**	**33.39**	**32.46**	**31.56**
Electricity Related Losses	0.05	0.06	0.05	0.06	0.07	0.08	0.08	0.09	0.11	0.11
Total	**27.90**	**28.68**	**28.48**	**28.25**	**30.82**	**30.29**	**29.72**	**33.48**	**32.58**	**31.68**

[1]Commercial trucks 8,500 to 10,000 pounds.
[2]Environmental Protection Agency rated miles per gallon.
[3]Combined car and light truck "on-the-road" estimate.
[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 2008 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, AEO2010 National Energy Modeling System runs TRNLOW.D120409A, AEO2010R.D111809A, and TRNHIGH.D120409A.

Table D4. Key Results for Integrated Technology Cases

Consumption and Emissions	2008	2015			2025			2035		
		Low Technology	Reference	High Technology	Low Technology	Reference	High Technology	Low Technology	Reference	High Technology
Energy Consumption by Sector (quadrillion Btu)										
Residential	11.34	11.25	11.07	10.21	12.21	11.69	10.01	12.92	12.12	10.26
Commercial	8.58	9.17	9.04	8.71	10.31	10.00	9.19	11.45	11.04	9.89
Industrial[1]	24.81	24.74	24.76	24.83	25.49	25.88	26.15	25.85	26.70	27.42
Transportation	27.85	28.64	28.42	28.17	30.69	30.21	29.51	33.29	32.46	31.65
Electric Power[2]	40.20	42.30	41.51	39.58	46.49	45.06	41.51	49.97	48.09	44.08
Total	**100.09**	**102.69**	**101.61**	**98.87**	**110.14**	**108.26**	**102.94**	**116.90**	**114.51**	**108.85**
Energy Consumption by Fuel (quadrillion Btu)										
Liquid Fuels and Other Petroleum[3]	38.35	39.06	38.81	38.50	40.70	40.14	39.41	42.93	42.02	41.06
Natural Gas	23.91	22.47	22.35	21.56	25.02	24.24	21.80	26.80	25.56	22.88
Coal	22.41	22.61	22.35	21.63	24.06	23.63	22.22	25.76	25.11	23.72
Nuclear Power	8.46	8.75	8.75	8.75	9.29	9.29	9.29	9.26	9.41	9.52
Renewable Energy[4]	6.73	9.60	9.14	8.23	10.85	10.75	10.01	11.89	12.18	11.50
Other[5]	0.24	0.20	0.20	0.20	0.22	0.21	0.20	0.26	0.22	0.17
Total	**100.09**	**102.69**	**101.61**	**98.87**	**110.14**	**108.26**	**102.94**	**116.90**	**114.51**	**108.85**
Energy Intensity (thousand Btu per 2000 dollar of GDP)	**8.59**	**7.72**	**7.65**	**7.45**	**6.28**	**6.16**	**5.86**	**5.23**	**5.12**	**4.86**
Carbon Dioxide Emissions by Sector (million metric tons)										
Residential	346	334	329	304	348	331	276	351	324	263
Commercial	218	223	222	217	233	233	221	241	245	233
Industrial[1]	966	989	988	987	1005	1003	998	1010	1001	1006
Transportation	1925	1930	1914	1897	2049	2015	1962	2190	2115	2052
Electric Power[6]	2359	2304	2277	2193	2505	2434	2235	2739	2634	2412
Total	**5814**	**5779**	**5731**	**5597**	**6140**	**6016**	**5692**	**6531**	**6320**	**5966**
Carbon Dioxide Emissions by Fuel (million metric tons)										
Petroleum	2436	2440	2422	2399	2537	2496	2437	2671	2588	2509
Natural Gas	1242	1178	1171	1129	1314	1272	1143	1410	1345	1202
Coal	2125	2150	2125	2057	2277	2236	2101	2438	2376	2244
Other[7]	12	12	12	12	12	12	12	12	12	12
Total	**5814**	**5779**	**5731**	**5597**	**6140**	**6016**	**5692**	**6531**	**6320**	**5966**
Carbon Dioxide Emissions (tons per person)	**19.0**	**17.7**	**17.5**	**17.1**	**17.1**	**16.8**	**15.9**	**16.7**	**16.2**	**15.3**

[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 2008 are model results and may differ slightly from official EIA data reports.
Source: Energy Information Administration, AEO2010 National Energy Modeling System runs LTRKITEN.D020510A, AEO2010R.D111809A, and HTRKITEN.D020510A.

Table D5. Key Results for Advanced Nuclear Cost Cases

(Gigawatts, Unless Otherwise Noted)

Net Summer Capacity, Generation, Emissions, and Fuel Prices	2008	2015			2025			2035		
		High Nuclear Cost	Reference	Low Nuclear Cost	High Nuclear Cost	Reference	Low Nuclear Cost	High Nuclear Cost	Reference	Low Nuclear Cost
Capacity										
Coal Steam	308.4	319.7	319.7	319.7	320.2	320.3	320.2	330.6	329.1	325.4
Oil and Natural Gas Steam	115.9	91.3	91.2	91.4	87.2	87.2	87.9	86.2	86.2	86.5
Combined Cycle	188.2	200.8	200.8	200.9	207.9	207.5	204.4	244.7	243.8	225.0
Combustion Turbine/Diesel	134.6	132.6	133.2	133.3	148.0	149.2	149.0	175.6	175.4	179.2
Nuclear Power	100.6	104.5	104.5	104.5	110.9	110.9	114.6	110.9	112.9	141.2
Pumped Storage	21.8	21.8	21.8	21.8	21.8	21.8	21.8	21.8	21.8	21.8
Fuel Cells	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Renewable Sources	110.0	154.7	154.7	152.8	157.1	157.0	155.6	167.2	168.4	161.0
Distributed Generation (Natural Gas)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.3	0.3	0.3
Combined Heat and Power[1]	28.5	43.1	43.0	43.0	60.1	59.9	60.1	78.3	78.1	78.1
Total	**1008.0**	**1068.5**	**1068.9**	**1067.4**	**1113.2**	**1113.7**	**1113.7**	**1215.7**	**1216.0**	**1218.5**
Cumulative Additions										
Coal Steam	0.0	15.6	15.6	15.6	17.6	17.6	17.6	28.0	26.4	22.8
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
Combined Cycle	0.0	13.0	13.0	13.2	20.1	19.7	16.7	57.0	56.1	37.3
Combustion Turbine/Diesel	0.0	7.7	7.7	7.7	23.2	23.9	23.6	51.0	50.4	54.0
Nuclear Power	0.0	1.2	1.2	1.2	6.4	6.4	10.1	6.4	8.4	36.6
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	44.7	44.7	42.8	47.2	47.0	45.7	57.3	58.5	51.0
Distributed Generation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.3	0.3	0.3
Combined Heat and Power[1]	0.0	14.5	14.4	14.5	31.6	31.4	31.5	49.7	49.6	49.6
Total	**0.0**	**96.8**	**96.7**	**95.0**	**146.0**	**146.0**	**145.2**	**249.7**	**249.5**	**251.6**
Cumulative Retirements	**0.0**	**39.2**	**38.5**	**38.4**	**44.8**	**44.2**	**43.4**	**46.0**	**45.5**	**45.1**
Generation by Fuel (billion kilowatthours)										
Coal	1976	2005	2006	2010	2106	2107	2105	2262	2254	2207
Petroleum	42	41	41	41	43	43	43	44	44	44
Natural Gas	799	606	604	608	759	759	745	954	944	833
Nuclear Power	806	834	834	834	886	886	913	883	898	1119
Pumped Storage	1	1	1	1	1	1	1	1	1	1
Renewable Sources	339	590	590	584	659	660	654	680	688	647
Distributed Generation	0	0	0	0	0	0	0	0	0	0
Combined Heat and Power[1]	150	204	204	204	314	314	314	432	431	431
Total	**4116**	**4281**	**4280**	**4282**	**4769**	**4769**	**4775**	**5256**	**5259**	**5282**
Carbon Dioxide Emissions by the Electric Power Sector (million metric tons)[2]										
Petroleum	40	35	35	35	37	37	37	38	38	38
Natural Gas	362	283	283	284	342	342	338	408	404	368
Coal	1946	1947	1947	1952	2043	2043	2041	2186	2180	2138
Other[3]	12	12	12	12	12	12	12	12	12	12
Total	**2359**	**2277**	**2277**	**2283**	**2434**	**2434**	**2427**	**2643**	**2634**	**2554**
Prices to the Electric Power Sector[2] (2008 dollars per million Btu)										
Petroleum	15.63	16.02	16.02	16.06	19.12	19.16	19.17	22.08	22.13	22.22
Natural Gas	9.09	6.09	6.08	6.11	6.74	6.75	6.69	8.51	8.46	8.11
Coal	2.05	2.01	2.01	2.01	1.99	1.99	1.99	2.09	2.09	2.07

[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 2008 are model results and may differ slightly from official EIA data reports.

Source: Energy Information Administration, AEO2010 National Energy Modeling System runs HCNUC10.D121109A, AEO2010R.D111809A, and LCNUC10.D121109A.

Table D6. Key Results for Nuclear 60 Year Life Case
(Gigawatts, Unless Otherwise Noted)

Net Summer Capacity, Generation, Emissions, and Fuel Prices	2008	2015		2025		2035	
		Reference	Nuclear 60 Year Life	Reference	Nuclear 60 Year Life	Reference	Nuclear 60 Year Life
Capacity							
Coal Steam	308.4	319.7	319.7	320.3	320.4	329.1	333.7
Oil and Natural Gas Steam	115.9	91.2	91.1	87.2	87.2	86.2	86.1
Combined Cycle	188.2	200.8	200.8	207.5	207.7	243.8	257.7
Combustion Turbine/Diesel	134.6	133.2	130.9	149.2	144.7	175.4	172.5
Nuclear Power	100.6	104.5	104.5	110.9	110.9	112.9	84.5
Pumped Storage	21.8	21.8	21.8	21.8	21.8	21.8	21.8
Fuel Cells	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Renewable Sources	110.0	154.7	154.4	157.0	157.3	168.4	168.5
Distributed Generation (Natural Gas)	0.0	0.0	0.0	0.0	0.0	0.3	0.2
Combined Heat and Power[1]	28.5	43.0	43.1	59.9	60.2	78.1	79.4
Total	**1008.0**	**1068.9**	**1066.4**	**1113.7**	**1110.4**	**1216.0**	**1204.4**
Cumulative Additions[2]							
Coal Steam	0.0	15.6	15.6	17.6	17.6	26.4	30.9
Combined Cycle	0.0	13.0	13.0	19.7	20.0	56.1	69.9
Combustion Turbine/Diesel	0.0	7.7	7.7	23.9	21.7	50.4	49.5
Nuclear Power	0.0	1.2	1.2	6.4	6.4	8.4	10.7
Renewable Sources	0.0	44.7	44.4	47.0	47.3	58.5	58.5
Distributed Generation	0.0	0.0	0.0	0.0	0.0	0.3	0.2
Combined Heat and Power[1]	0.0	14.4	14.5	31.4	31.7	49.6	50.8
Total	**0.0**	**96.7**	**96.5**	**146.0**	**144.7**	**249.5**	**270.6**
Cumulative Retirements[2]							
Coal Steam	0.0	4.3	4.3	5.7	5.6	5.7	5.6
Oil and Natural Gas Steam	0.0	24.7	24.7	28.7	28.6	29.7	29.7
Combined Cycle	0.0	0.4	0.4	0.4	0.4	0.4	0.4
Combustion Turbine/Diesel	0.0	9.1	11.4	9.3	11.6	9.6	11.6
Nuclear Power	0.0	0.0	0.0	0.0	0.0	0.0	30.8
Renewable Sources	0.0	0.1	0.1	0.1	0.1	0.1	0.1
Total	**0.0**	**38.5**	**40.9**	**44.2**	**46.3**	**45.5**	**78.2**
Generation by Fuel (billion kilowatthours)							
Coal	1976	2006	2008	2107	2108	2254	2293
Petroleum	42	41	41	43	43	44	44
Natural Gas	799	604	604	759	756	944	1078
Nuclear Power	806	834	834	886	886	898	671
Pumped Storage	1	1	1	1	1	1	1
Renewable Sources	339	590	588	660	659	688	688
Distributed Generation	0	0	0	0	0	0	0
Combined Heat and Power[1]	150	204	204	314	315	431	439
Total	**4116**	**4280**	**4280**	**4769**	**4767**	**5259**	**5214**
Carbon Dioxide Emissions by the Electric Power Sector (million metric tons)[3]							
Petroleum	40	35	35	37	37	38	38
Natural Gas	362	283	283	342	341	404	451
Coal	1946	1947	1949	2043	2044	2180	2213
Other[4]	12	12	12	12	12	12	12
Total	**2359**	**2277**	**2279**	**2434**	**2433**	**2634**	**2714**
Prices to the Electric Power Sector[3] (2008 dollars per million Btu)							
Petroleum	15.63	16.02	16.07	19.16	19.23	22.13	22.29
Natural Gas	9.09	6.08	6.09	6.75	6.73	8.46	8.95
Coal	2.05	2.01	2.01	1.99	1.99	2.09	2.10

[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]Only non-zero categories shown.
[3]Includes electricity-only and combined heat and power plants whose primary business to sell electricity, or electricity and heat, to the public.
[4]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 2008 are model results and may differ slightly from official EIA data reports.
Source: Energy Information Administration, AEO2010 National Energy Modeling System runs AEO2010R.D111809A, and NUCRET.D123009A.

Table D7. Key Results for Electric Power Sector Fossil Technology Cases
(Gigawatts, Unless Otherwise Noted)

Net Summer Capacity, Generation Consumption, and Emissions	2008	2015			2025			2035		
		High Fossil Cost	Reference	Low Fossil Cost	High Fossil Cost	Reference	Low Fossil Cost	High Fossil Cost	Reference	Low Fossil Cost
Capacity										
Pulverized Coal	307.8	318.5	318.6	318.5	317.0	317.1	318.3	322.5	324.4	338.3
Coal Gasification Combined-Cycle	0.5	1.1	1.1	1.1	3.1	3.1	3.1	3.2	4.6	20.6
Conventional Natural Gas Combined-Cycle	188.2	200.8	200.8	200.8	201.0	201.1	201.1	201.1	201.1	201.1
Advanced Natural Gas Combined-Cycle	0.0	0.0	0.0	0.0	3.7	6.4	17.6	34.2	42.8	49.2
Conventional Combustion Turbine	134.6	127.5	131.4	133.9	127.1	131.4	134.2	127.3	131.2	134.2
Advanced Combustion Turbine	0.0	2.9	1.9	2.8	17.6	17.8	16.7	45.2	44.2	37.7
Fuel Cells	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Nuclear	100.6	104.5	104.5	104.5	110.9	110.9	110.9	112.4	112.9	110.9
Oil and Natural Gas Steam	115.9	91.5	91.2	92.4	87.1	87.2	87.8	87.0	86.2	86.0
Renewable Sources/Pumped Storage	131.8	175.2	176.5	173.4	178.9	178.8	176.1	193.7	190.3	180.7
Distributed Generation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.0	0.3	0.0
Combined Heat and Power[1]	28.5	43.0	43.0	42.9	60.1	59.9	59.8	78.7	78.1	77.3
Total	**1008.0**	**1064.9**	**1068.9**	**1070.4**	**1106.4**	**1113.7**	**1125.6**	**1206.1**	**1216.0**	**1235.9**
Cumulative Additions										
Pulverized Coal	0.0	15.0	15.0	15.0	17.0	17.0	18.1	22.5	24.3	38.2
Coal Gasification Combined-Cycle	0.0	0.6	0.6	0.6	0.6	0.6	0.6	0.6	2.1	18.0
Conventional Natural Gas Combined-Cycle	0.0	13.0	13.0	13.0	13.2	13.3	13.3	13.3	13.3	13.3
Advanced Natural Gas Combined-Cycle	0.0	0.0	0.0	0.0	3.7	6.4	17.6	34.2	42.8	49.2
Conventional Combustion Turbine	0.0	4.9	5.8	5.0	4.9	6.1	5.2	5.1	6.2	5.2
Advanced Combustion Turbine	0.0	2.9	1.9	2.8	17.6	17.8	16.7	45.2	44.2	37.7
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	1.2	1.2	1.2	6.4	6.4	6.4	7.8	8.4	6.4
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	43.4	44.7	41.6	47.1	47.0	44.3	61.9	58.5	48.9
Distributed Generation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.0	0.3	0.0
Combined Heat and Power[1]	0.0	14.4	14.4	14.4	31.5	31.4	31.2	50.1	49.6	48.8
Total	**0.0**	**95.4**	**96.7**	**93.6**	**142.0**	**146.0**	**153.5**	**241.8**	**249.5**	**265.6**
Cumulative Retirements	**0.0**	**41.3**	**38.5**	**33.9**	**47.6**	**44.2**	**39.9**	**47.7**	**45.5**	**41.6**
Generation by Fuel (billion kilowatthours)										
Coal	1976	2013	2006	2012	2108	2107	2108	2228	2254	2441
Petroleum	42	41	41	41	43	43	43	44	44	45
Natural Gas	799	602	604	612	750	759	777	932	944	852
Nuclear Power	806	834	834	834	886	886	886	893	898	883
Renewable Sources/Pumped Storage	340	588	591	579	664	661	653	719	688	648
Distributed Generation	0	0	0	0	0	0	0	1	0	0
Combined Heat and Power[1]	150	204	204	203	314	314	313	433	431	428
Total	**4116**	**4282**	**4280**	**4282**	**4766**	**4769**	**4780**	**5252**	**5259**	**5297**
Fuel Consumption by the Electric Power Sector (quadrillion Btu)[2]										
Coal	20.55	20.58	20.51	20.57	21.65	21.63	21.63	22.87	23.09	24.51
Petroleum	0.47	0.46	0.46	0.46	0.48	0.48	0.48	0.49	0.49	0.50
Natural Gas	6.84	5.31	5.32	5.38	6.41	6.45	6.52	7.60	7.62	6.92
Nuclear Power	8.46	8.75	8.75	8.75	9.29	9.29	9.29	9.37	9.41	9.26
Renewable Sources	3.65	6.27	6.27	6.12	7.05	7.00	6.88	7.54	7.26	6.86
Total	**40.09**	**41.50**	**41.44**	**41.41**	**45.01**	**44.98**	**44.92**	**47.99**	**48.00**	**48.17**
Carbon Dioxide Emissions by the Electric Power Sector (million metric tons)[2]										
Coal	1946	1954	1947	1953	2045	2043	2043	2161	2180	2315
Petroleum	40	35	35	36	37	37	37	38	38	39
Natural Gas	362	282	283	286	340	342	346	403	404	367
Other[3]	12	12	12	12	12	12	12	12	12	12
Total	**2359**	**2283**	**2277**	**2286**	**2434**	**2434**	**2437**	**2613**	**2634**	**2732**

[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 2008 are model results and may differ slightly from official EIA data reports.
Source: Energy Information Administration, AEO2010 National Energy Modeling System runs HCFOSS10.D020510A, AEO2010R.D111809A, and LCFOSS10.D020510A.

Table D8. Energy Consumption and Carbon Dioxide Emissions for Extended Policy Cases

Consumption and Emissions	2008	2015			2025			2035		
		Reference	Extended Policies	No Sunset	Reference	Extended Policies	No Sunset	Reference	Extended Policies	No Sunset
Energy Consumption by Sector (quadrillion Btu)										
Residential	11.34	11.07	10.88	11.01	11.69	10.81	11.25	12.12	10.83	11.33
Commercial	8.58	9.04	9.03	9.04	10.00	10.04	10.03	11.04	11.11	11.10
Industrial[1]	24.81	24.76	24.77	24.76	25.88	25.96	26.78	26.70	26.54	27.95
Transportation	27.85	28.42	28.42	28.48	30.21	29.93	30.25	32.46	31.39	32.48
Electric Power[2]	40.20	41.51	41.07	41.38	45.06	43.65	44.47	48.09	46.76	47.56
Total	**100.09**	**101.61**	**101.06**	**101.49**	**108.26**	**106.28**	**108.39**	**114.51**	**111.41**	**114.89**
Energy Consumption by Fuel (quadrillion Btu)										
Liquid Fuels and Other Petroleum[3]	38.35	38.81	38.80	38.86	40.14	39.80	40.10	42.02	40.86	41.90
Natural Gas	23.91	22.35	22.41	22.27	24.24	23.49	23.77	25.56	24.03	24.40
Coal	22.41	22.35	22.29	22.33	23.63	23.43	23.72	25.11	24.52	24.91
Nuclear Power	8.46	8.75	8.75	8.75	9.29	9.29	9.29	9.41	9.26	9.26
Renewable Energy[4]	6.73	9.14	8.62	9.07	10.75	10.06	11.30	12.18	12.55	14.22
Other[5]	0.24	0.20	0.20	0.20	0.21	0.20	0.21	0.22	0.20	0.20
Total	**100.09**	**101.61**	**101.06**	**101.49**	**108.26**	**106.28**	**108.39**	**114.51**	**111.41**	**114.89**
Energy Intensity (thousand Btu per 2000 dollar of GDP)	**8.59**	**7.65**	**7.61**	**7.64**	**6.16**	**6.05**	**6.17**	**5.12**	**4.98**	**5.14**
Carbon Dioxide Emissions by Sector (million metric tons)										
Residential	346	329	324	327	331	311	318	324	295	302
Commercial	218	222	222	222	233	235	234	245	249	249
Industrial[1]	966	988	988	989	1003	1003	1008	1001	1000	1000
Transportation	1925	1914	1914	1916	2015	1995	1967	2115	2062	2060
Electric Power[6]	2359	2277	2279	2272	2434	2388	2417	2634	2514	2563
Total	**5814**	**5731**	**5727**	**5726**	**6016**	**5932**	**5945**	**6320**	**6120**	**6174**
Carbon Dioxide Emissions by Fuel (million metric tons)										
Petroleum	2436	2422	2422	2424	2496	2471	2442	2588	2525	2523
Natural Gas	1242	1171	1174	1167	1272	1233	1247	1345	1263	1283
Coal	2125	2125	2119	2124	2236	2217	2244	2376	2320	2357
Other[7]	12	12	12	12	12	12	12	12	12	12
Total	**5814**	**5731**	**5727**	**5726**	**6016**	**5932**	**5945**	**6320**	**6120**	**6174**
Carbon Dioxide Emissions (tons per person)	**19.0**	**17.5**	**17.5**	**17.5**	**16.8**	**16.5**	**16.6**	**16.2**	**15.7**	**15.8**

[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 2008 are model results and may differ slightly from official EIA data reports.
Source: Energy Information Administration, AEO2010 National Energy Modeling System runs AEO2010R.D111809A, EXTENDED.D122409A, and NOSUNSET.D012510A.

Table D9. Electricity Generation and Generating Capacity in Extended Policy Cases
(Gigawatts, Unless Otherwise Noted)

Net Summer Capacity, Generation Consumption, and Emissions	2008	2015			2025			2035		
		Reference	Extended Policies	No Sunset	Reference	Extended Policies	No Sunset	Reference	Extended Policies	No Sunset
Capacity	**1008.0**	**1068.9**	**1050.2**	**1061.7**	**1113.7**	**1102.2**	**1110.5**	**1216.0**	**1214.0**	**1216.7**
Electric Power Sector[1]	979.5	1026.0	1007.3	1018.5	1053.8	1014.6	1022.9	1137.9	1070.9	1070.4
Pulverized Coal	307.8	318.6	316.9	318.5	317.1	315.3	316.1	324.4	317.7	319.6
Coal Gasification Combined-Cycle	0.5	1.1	1.1	1.1	3.1	3.1	3.1	4.6	3.1	3.9
Conventional Natural Gas Combined-Cycle	188.2	200.8	200.8	200.8	201.1	200.8	200.8	201.1	200.8	200.8
Advanced Natural Gas Combined-Cycle	0.0	0.0	0.0	0.0	6.4	0.8	1.2	42.8	8.7	9.0
Conventional Combustion Turbine	134.6	131.4	126.0	126.1	131.4	124.8	124.0	131.2	124.8	123.9
Advanced Combustion Turbine	0.0	1.9	2.3	1.9	17.8	4.5	4.3	44.2	13.0	9.0
Fuel Cells	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Nuclear	100.6	104.5	104.5	104.5	110.9	110.9	110.9	112.9	110.9	110.9
Oil and Natural Gas Steam	115.9	91.2	90.2	88.6	87.2	85.0	82.6	86.2	83.8	81.8
Renewable Sources	110.0	154.7	143.5	155.2	157.0	147.4	158.1	168.4	186.1	189.6
Pumped Storage	21.8	21.8	21.8	21.8	21.8	21.8	21.8	21.8	21.8	21.8
Distributed Generation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.3	0.2	0.1
Combined Heat and Power[2]	28.5	43.0	42.9	43.1	59.9	87.6	87.7	78.1	143.1	146.3
Fossil Fuels/Other	21.8	26.0	26.0	26.1	30.6	31.0	31.4	37.2	38.2	38.9
Renewable Fuels	6.8	16.9	17.0	17.0	29.3	56.6	56.2	41.0	104.9	107.4
Cumulative Additions	**0.0**	**96.7**	**85.3**	**97.2**	**146.0**	**144.1**	**155.4**	**249.5**	**257.2**	**262.5**
Electric Power Sector[1]	0.0	82.3	70.9	82.6	114.6	85.1	96.3	200.0	142.7	144.7
Pulverized Coal	0.0	15.0	15.0	15.0	17.0	17.0	17.0	24.3	19.4	20.5
Coal Gasification Combined-Cycle	0.0	0.6	0.6	0.6	0.6	0.6	0.6	2.1	0.6	1.4
Conventional Natural Gas Combined-Cycle	0.0	13.0	13.0	13.0	13.3	13.0	13.0	13.3	13.0	13.0
Advanced Natural Gas Combined-Cycle	0.0	0.0	0.0	0.0	6.4	0.8	1.2	42.8	8.7	9.0
Conventional Combustion Turbine	0.0	5.8	5.2	5.6	6.1	5.2	5.6	6.2	5.2	5.6
Advanced Combustion Turbine	0.0	1.9	2.3	1.9	17.8	4.5	4.3	44.2	13.0	9.0
Nuclear	0.0	1.2	1.2	1.2	6.4	6.4	6.4	8.4	6.4	6.4
Renewable Sources	0.0	44.7	33.6	45.2	47.0	37.5	48.1	58.5	76.1	79.6
Distributed Generation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.3	0.2	0.1
Combined Heat and Power[2]	0.0	14.4	14.4	14.6	31.4	59.0	59.1	49.6	114.6	117.7
Fossil Fuels/Other	0.0	4.3	4.2	4.3	8.8	9.2	9.6	15.4	16.4	17.1
Renewable Fuels	0.0	10.1	10.2	10.3	22.6	49.8	49.5	34.2	98.2	100.7
Cumulative Retirements	**0.0**	**38.5**	**45.9**	**46.3**	**44.2**	**53.9**	**56.8**	**45.5**	**55.1**	**57.7**
Generation by Fuel (billion kilowatthours)	**4116**	**4280**	**4253**	**4273**	**4769**	**4668**	**4749**	**5259**	**5163**	**5263**
Electric Power Sector[1]	3966	4077	4049	4068	4456	4308	4385	4828	4626	4694
Coal	1976	2006	2001	2005	2107	2091	2117	2254	2190	2230
Petroleum	42	41	41	40	43	43	42	44	43	43
Natural Gas	799	604	626	595	759	689	695	944	759	788
Nuclear Power	806	834	834	834	886	886	886	898	883	883
Renewable Sources	339	590	547	593	660	599	644	688	750	750
Pumped Storage	1	1	1	1	1	1	1	1	1	1
Distributed Generation	0	0	0	0	0	0	0	0	0	0
Combined Heat and Power[1]	150	204	203	204	314	361	364	431	538	569
Fossil Fuels/Other	115	145	145	146	179	182	185	228	234	240
Renewable Fuels	35	59	59	59	135	179	179	204	303	329
Average Electricity Price (cents per kilowatthour)	**9.8**	**8.9**	**8.8**	**8.9**	**9.3**	**9.0**	**9.1**	**10.2**	**9.6**	**9.7**

[1]Includes electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public. Includes small power producers and exempt wholesale generators.
[2]Includes combined heat and power plants and electricity-only plants in the commercial and industrial sectors. Includes small on-site generating systems in the residential, commercial, and industrial sectors used primarily for own-use generation, but which may also sell some power to the grid. Excludes off-grid photovoltaics and other generators not connected to the distribution or transmission systems.
[2]Includes electricity-only and combined heat and power plants whose primary business to sell electricity, or electricity and heat, to the public.
Note: Totals may not equal sum of components due to independent rounding. Data for 2008 are model results and may differ slightly from official EIA data reports.
Source: Energy Information Administration, AEO2010 National Energy Modeling System runs AEO2010R.D111809A, EXTENDED.D122409A, and NOSUNSET.D012510A.

Table D10. Key Results for Renewable Technology Cases

Capacity, Generation, and Emissions	2008	2015 High Renewable Cost	2015 Reference	2015 Low Renewable Cost	2025 High Renewable Cost	2025 Reference	2025 Low Renewable Cost	2035 High Renewable Cost	2035 Reference	2035 Low Renewable Cost
Net Summer Capacity (gigawatts)										
Electric Power Sector[1]										
Conventional Hydropower	76.51	77.08	77.03	77.24	77.38	77.34	77.24	77.79	77.52	78.14
Geothermal[2]	2.44	3.28	3.24	3.89	3.28	3.27	4.13	3.43	3.82	6.27
Municipal Waste[3]	3.43	4.76	4.75	4.77	4.76	4.75	4.77	4.76	4.75	4.77
Wood and Other Biomass[4]	2.17	4.59	4.46	5.53	4.90	4.75	7.67	7.49	11.87	31.01
Solar Thermal	0.53	0.87	0.87	0.87	0.91	0.91	0.91	0.96	0.96	0.96
Solar Photovoltaic	0.05	0.14	0.14	0.14	0.31	0.31	0.31	0.45	0.45	0.45
Wind	24.89	61.60	64.18	74.63	64.43	65.62	75.86	67.88	69.08	84.37
Total	**110.01**	**152.32**	**154.68**	**167.06**	**155.97**	**156.95**	**170.88**	**162.76**	**168.45**	**205.97**
End-Use Sector[5]										
Conventional Hydropower	0.69	0.69	0.69	0.69	0.69	0.69	0.69	0.69	0.69	0.69
Geothermal	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Municipal Waste[6]	0.33	0.33	0.33	0.33	0.33	0.33	0.33	0.33	0.33	0.33
Wood and Other Biomass	4.86	6.12	6.31	6.49	10.80	16.04	18.90	14.51	24.51	28.36
Solar Photovoltaic	0.80	6.77	8.07	10.06	8.30	10.27	13.41	8.87	13.14	18.46
Wind	0.09	1.50	1.52	4.30	1.93	2.01	6.24	2.14	2.29	7.90
Total	**6.77**	**15.42**	**16.92**	**21.87**	**22.05**	**29.34**	**39.57**	**26.54**	**40.96**	**55.73**
Generation (billion kilowatthours)										
Electric Power Sector[1]										
Coal	1976	2011	2006	1989	2106	2107	2108	2243	2254	2201
Petroleum	42	41	41	41	43	43	43	44	44	44
Natural Gas	799	615	604	568	788	759	689	976	944	818
Total Fossil	**2817**	**2667**	**2651**	**2598**	**2937**	**2909**	**2840**	**3263**	**3242**	**3062**
Conventional Hydropower	245.45	296.67	296.56	297.29	298.68	298.57	297.43	300.35	299.45	302.12
Geothermal	14.86	23.87	23.53	28.60	23.90	23.79	30.55	25.05	28.13	47.42
Municipal Waste[7]	14.49	25.05	24.95	25.09	25.05	24.95	25.09	25.05	24.95	25.09
Wood and Other Biomass[4]	10.90	46.22	47.22	60.97	106.18	109.06	128.02	106.25	117.45	258.18
Dedicated Plants	9.00	27.73	26.78	34.92	29.66	29.85	52.16	50.06	82.01	219.49
Cofiring	1.90	18.49	20.44	26.05	76.53	79.21	75.86	56.19	35.43	38.70
Solar Thermal	0.81	1.80	1.80	1.80	1.94	1.94	1.94	2.10	2.10	2.10
Solar Photovoltaic	0.03	0.34	0.34	0.34	0.76	0.76	0.76	1.13	1.13	1.13
Wind	52.03	183.40	195.93	230.29	193.06	201.26	234.56	205.03	214.59	259.85
Total Renewable	**338.56**	**577.36**	**590.33**	**644.39**	**649.58**	**660.33**	**718.34**	**664.97**	**687.80**	**895.90**
End-Use Sector[5]										
Total Fossil	**102**	**122**	**122**	**122**	**157**	**157**	**154**	**207**	**205**	**197**
Conventional Hydropower[8]	3.35	3.35	3.35	3.35	3.35	3.35	3.35	3.35	3.35	3.35
Geothermal	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Municipal Waste[6]	2.02	2.79	2.79	2.79	2.79	2.79	2.79	2.79	2.79	2.79
Wood and Other Biomass	27.89	36.03	37.25	38.40	70.58	109.23	129.86	97.94	172.75	202.06
Solar Photovoltaic	1.26	10.77	13.12	16.14	13.20	16.73	21.56	14.12	21.58	30.12
Wind	0.12	2.08	2.10	5.45	2.69	2.79	8.04	2.98	3.19	10.38
Total Renewable	**34.63**	**55.01**	**58.60**	**66.12**	**92.61**	**134.88**	**165.60**	**121.17**	**203.65**	**248.69**
Carbon Dioxide Emissions by the Electric Power Sector (million metric tons)[1]										
Coal	1945.9	1952.2	1947.5	1929.6	2042.6	2043.2	2043.3	2167.2	2180.4	2130.7
Petroleum	39.7	35.4	35.4	35.1	37.0	37.0	36.8	38.0	38.0	37.7
Natural Gas	362.0	286.7	282.5	268.6	352.9	342.3	315.5	415.6	404.3	360.2
Other[9]	11.6	11.6	11.6	11.6	11.6	11.6	11.6	11.6	11.6	11.6
Total	**2359.1**	**2285.9**	**2276.9**	**2244.9**	**2444.0**	**2434.1**	**2407.2**	**2632.3**	**2634.2**	**2540.2**

[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 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 2008 are model results and may differ slightly from official EIA data reports.
Source: Energy Information Administration, AEO2010 National Energy Modeling System runs HIRENCST10.D011410A, AEO2010R.D111809A, and LORENCST10.D011510A.

Table D11. Natural Gas Supply and Disposition, Oil and Gas Technological Progress Cases
(Trillion Cubic Feet per Year, Unless Otherwise Noted)

Supply, Disposition, and Prices	2008	2015			2025			2035		
		Slow Technology	Reference	Rapid Technology	Slow Technology	Reference	Rapid Technology	Slow Technology	Reference	Rapid Technology
Natural Gas Prices										
(2008 dollars per million Btu)										
Henry Hub Spot Price	8.86	6.73	6.27	6.01	7.98	6.99	6.95	9.75	8.88	8.14
Average Lower 48 Wellhead Price[1]	7.85	5.95	5.54	5.31	7.05	6.18	6.14	8.61	7.84	7.19
(2008 dollars per thousand cubic feet)										
Average Lower 48 Wellhead Price[1]	8.07	6.11	5.70	5.46	7.24	6.35	6.31	8.85	8.06	7.39
Dry Gas Production[2]	**20.56**	**18.66**	**19.29**	**19.75**	**20.64**	**21.31**	**21.01**	**22.32**	**23.27**	**24.00**
Lower 48 Onshore	17.56	15.50	16.09	16.47	15.36	15.96	17.06	16.26	17.07	17.48
Associated-Dissolved	1.39	1.41	1.44	1.43	1.26	1.25	1.25	1.03	1.03	1.04
Non-Associated	16.17	14.09	14.65	15.04	14.11	14.71	15.81	15.23	16.04	16.44
Conventional[3]	12.71	8.77	8.92	8.84	7.86	8.00	8.12	7.72	8.11	7.84
Unconventional	3.46	5.32	5.73	6.20	6.25	6.71	7.69	7.51	7.93	8.60
Gas Shale	1.49	3.58	3.85	4.26	4.62	4.94	5.77	5.63	6.00	6.65
Coalbed Methane	1.97	1.74	1.89	1.93	1.63	1.77	1.91	1.87	1.93	1.95
Lower 48 Offshore	2.62	2.88	2.91	2.99	3.40	3.46	3.67	4.20	4.33	4.65
Associated-Dissolved	0.55	0.78	0.79	0.81	0.86	0.90	0.94	0.94	1.00	1.07
Non-Associated	2.06	2.10	2.12	2.18	2.54	2.56	2.73	3.26	3.33	3.59
Alaska	0.38	0.29	0.29	0.29	1.88	1.88	0.28	1.87	1.87	1.87
Supplemental Natural Gas[4]	0.05	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06
Net Imports	**2.95**	**2.39**	**2.38**	**2.39**	**2.19**	**2.17**	**2.54**	**1.52**	**1.46**	**1.86**
Pipeline[5]	2.65	1.27	1.29	1.33	0.83	0.89	1.27	0.65	0.64	1.07
Liquefied Natural Gas	0.30	1.13	1.09	1.06	1.36	1.28	1.26	0.87	0.83	0.79
Total Supply	**23.57**	**21.12**	**21.73**	**22.21**	**22.90**	**23.54**	**23.62**	**23.91**	**24.80**	**25.93**
Consumption by Sector										
Residential	4.87	4.68	4.71	4.73	4.83	4.89	4.90	4.81	4.87	4.92
Commercial	3.12	3.18	3.23	3.25	3.37	3.45	3.46	3.59	3.69	3.75
Industrial[6]	6.65	6.83	6.88	6.93	6.82	6.94	6.94	6.58	6.72	6.86
Electric Power[7]	6.66	4.75	5.18	5.54	5.95	6.28	6.44	6.90	7.42	8.23
Transportation[8]	0.04	0.05	0.05	0.05	0.11	0.11	0.11	0.18	0.19	0.20
Pipeline Fuel	0.63	0.58	0.60	0.61	0.68	0.70	0.64	0.70	0.72	0.75
Lease and Plant Fuel[9]	1.28	1.05	1.08	1.10	1.16	1.19	1.15	1.20	1.25	1.29
Total	**23.25**	**21.13**	**21.74**	**22.21**	**22.93**	**23.57**	**23.65**	**23.97**	**24.86**	**26.00**
Discrepancy[10]	**0.32**	**-0.01**	**-0.01**	**-0.01**	**-0.03**	**-0.03**	**-0.03**	**-0.06**	**-0.07**	**-0.07**
Lower 48 End of Year Reserves	**235.63**	**250.97**	**254.61**	**256.88**	**253.38**	**259.77**	**263.45**	**264.86**	**267.94**	**270.89**

[1]Represents lower 48 onshore and offshore supplies.
[2]Marketed production (wet) minus extraction losses.
[3]Includes tight gas.
[4]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.
[5]Includes any natural gas regasified in the Bahamas and transported via pipeline to Florida.
[6]Includes energy for combined heat and power plants, except those whose primary business is to sell electricity, or electricity and heat, to the public.
[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 a vehicle fuel.
[9]Represents natural gas used in field gathering and 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, 2008 values include net storage injections.
Note: Totals may not equal sum of components due to independent rounding. Data for 2008 are model results and may differ slightly from official EIA data reports.
Sources: 2008 supply values: Energy Information Administration (EIA), *Natural Gas Monthly*, DOE/EIA-0130(2009/07) (Washington, DC, July 2009). 2008 consumption based on: EIA, *Annual Energy Review 2008*, DOE/EIA-0384(2008) (Washington, DC, June 2009). **Projections:** EIA, AEO2010 National Energy Modeling System runs OGLTEC10.D121409A, AEO2010R.D111809A, and OGHTEC10.D121309A.

Table D12. Liquid Fuels Supply and Disposition, Oil and Gas Technological Progress Cases
(Million Barrels per Day, Unless Otherwise Noted)

Supply, Disposition, and Prices	2008	2015			2025			2035		
		Slow Technology	Reference	Rapid Technology	Slow Technology	Reference	Rapid Technology	Slow Technology	Reference	Rapid Technology
Prices (2008 dollars per barrel)										
Imported Low Sulfur Light Crude Oil[1]	**99.57**	**94.91**	**94.52**	**94.57**	**116.58**	**115.09**	**114.90**	**135.27**	**133.22**	**133.05**
Imported Crude Oil[1]	**92.61**	**87.29**	**86.88**	**86.77**	**106.12**	**104.49**	**103.45**	**123.30**	**121.37**	**121.13**
Crude Oil Supply										
Domestic Crude Oil Production[2]	4.96	5.71	5.77	5.81	5.89	6.13	6.37	5.93	6.27	6.68
Alaska	0.69	0.49	0.49	0.49	0.73	0.74	0.76	0.43	0.45	0.45
Lower 48 Onshore	3.00	3.32	3.34	3.33	3.11	3.25	3.36	3.29	3.46	3.65
Lower 48 Offshore	1.27	1.90	1.94	1.99	2.04	2.14	2.25	2.20	2.36	2.59
Net Crude Oil Imports	9.75	8.96	8.88	8.83	8.84	8.60	8.39	8.94	8.65	8.22
Other Crude Oil Supply	-0.06	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total Crude Oil Supply	**14.66**	**14.67**	**14.66**	**14.64**	**14.73**	**14.73**	**14.75**	**14.87**	**14.92**	**14.90**
Other Petroleum Supply	**4.09**	**4.01**	**4.05**	**4.08**	**3.98**	**4.01**	**4.05**	**3.93**	**3.98**	**3.99**
Natural Gas Plant Liquids	1.78	1.72	1.77	1.80	1.69	1.74	1.83	1.77	1.83	1.87
Net Petroleum Product Imports[3]	1.39	1.25	1.24	1.24	1.11	1.10	1.06	1.04	1.02	1.00
Refinery Processing Gain[4]	1.00	1.05	1.04	1.04	1.18	1.17	1.16	1.12	1.13	1.12
Product Stock Withdrawal	-0.07	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Other Non-petroleum Supply	**0.78**	**1.42**	**1.42**	**1.43**	**2.12**	**2.11**	**2.10**	**3.22**	**3.11**	**3.13**
From Renewable Sources[5]	0.71	1.10	1.10	1.10	1.63	1.63	1.62	2.68	2.58	2.57
From Non-renewable Sources[6]	0.07	0.32	0.32	0.32	0.49	0.48	0.48	0.54	0.53	0.57
Total Primary Supply[7]	**19.54**	**20.11**	**20.13**	**20.15**	**20.83**	**20.86**	**20.90**	**22.02**	**22.00**	**22.02**
Refined Petroleum Products Supplied										
Residential and Commercial	0.98	0.89	0.89	0.89	0.83	0.83	0.83	0.79	0.79	0.79
Industrial[8]	4.75	4.81	4.82	4.83	4.82	4.81	4.83	4.68	4.67	4.67
Transportation	13.88	14.25	14.27	14.27	15.11	15.14	15.15	16.38	16.38	16.40
Electric Power[9]	0.21	0.20	0.20	0.21	0.21	0.21	0.21	0.22	0.22	0.22
Total	**19.53**	**20.16**	**20.18**	**20.20**	**20.97**	**20.99**	**21.02**	**22.07**	**22.06**	**22.09**
Discrepancy[10]	**0.01**	**-0.05**	**-0.05**	**-0.05**	**-0.14**	**-0.13**	**-0.11**	**-0.05**	**-0.06**	**-0.07**
Lower 48 End of Year Reserves (billion barrels)[2]	**17.18**	**19.24**	**19.41**	**19.49**	**21.10**	**22.44**	**23.24**	**22.83**	**23.57**	**24.71**

[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), biodiesel (including imports), pyrolysis oils, biomass-derived Fischer-Tropsch liquids, and renewable feedstocks for the production of green diesel and gasoline.
[6]Includes alcohols, ethers, domestic sources of blending components, other hydrocarbons, natural gas converted to liquid fuel, and coal converted to liquid fuel.
[7]Total crude supply plus natural gas plant liquids, other inputs, refinery processing gain, and net product imports.
[8]Includes consumption for combined heat and power, which produces electricity and other useful thermal energy.
[9]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.
[10]Balancing item. Includes unaccounted for supply, losses and gains.
Note: Totals may not equal sum of components due to independent rounding. Data for 2008 are model results and may differ slightly from official EIA data reports.
Sources: 2008 product supplied data and imported crude oil price based on: Energy Information Administration (EIA), *Annual Energy Review 2008*, DOE/EIA-0384(2008) (Washington, DC, June 2009). 2008 imported low sulfur light crude oil price: EIA, Form EIA-856, "Monthly Foreign Crude Oil Acquisition Report." Other 2008 data: EIA, *Petroleum Supply Annual 2008,* DOE/EIA-0340(2008)/1 (Washington, DC, June 2009). **Projections:** EIA, AEO2010 National Energy Modeling System runs OGLTEC10.D121409A, AEO2010R.D111809A, and OGHTEC10.D121309A.

Table D13. Natural Gas Supply and Disposition, Low Permeability Cases
(Trillion Cubic Feet per Year, Unless Otherwise Noted)

Supply, Disposition, and Prices	2008	2025				2035			
		High Shale Gas	Reference	No Shale Gas	No Low Permeability	High Shale Gas	Reference	No Shale Gas	No Low Permeability
Natural Gas Prices									
(2008 dollars per million Btu)									
Henry Hub Spot Price	8.86	6.60	6.99	8.34	8.71	7.62	8.88	10.37	10.88
Average Lower 48 Wellhead Price[1]	7.85	5.83	6.18	7.37	7.69	6.73	7.84	9.16	9.60
(2008 dollars per thousand cubic feet)									
Average Lower 48 Wellhead Price[1]	8.07	5.99	6.35	7.58	7.91	6.92	8.06	9.42	9.87
Dry Gas Production[2]	**20.56**	**22.13**	**21.31**	**18.30**	**17.19**	**25.86**	**23.27**	**19.05**	**17.40**
Lower 48 Onshore	17.56	18.69	15.96	12.30	11.03	19.97	17.07	12.53	10.40
Associated-Dissolved	1.39	1.29	1.25	1.25	1.25	1.07	1.03	1.04	1.04
Non-Associated	16.17	17.39	14.71	11.04	9.77	18.90	16.04	11.48	9.36
Conventional[3]	12.71	7.41	8.00	8.88	7.49	7.10	8.11	9.20	6.88
Unconventional	3.46	9.98	6.71	2.17	2.28	11.81	7.93	2.29	2.48
Gas Shale	1.49	8.39	4.94	0.17	0.17	10.18	6.00	0.06	0.06
Coalbed Methane	1.97	1.59	1.77	2.00	2.10	1.63	1.93	2.23	2.42
Lower 48 Offshore	2.62	3.17	3.46	4.12	4.29	4.02	4.33	4.65	5.13
Associated-Dissolved	0.55	0.86	0.90	0.97	0.98	0.99	1.00	1.01	1.05
Non-Associated	2.06	2.31	2.56	3.15	3.30	3.03	3.33	3.64	4.08
Alaska	0.38	0.28	1.88	1.88	1.88	1.87	1.87	1.87	1.87
Supplemental Natural Gas[4]	0.05	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06
Net Imports	**2.95**	**1.89**	**2.17**	**3.77**	**4.41**	**0.82**	**1.46**	**3.71**	**4.49**
Pipeline[5]	2.65	0.66	0.89	1.49	1.64	0.06	0.64	1.86	2.11
Liquefied Natural Gas	0.30	1.22	1.28	2.27	2.77	0.76	0.83	1.85	2.37
Total Supply	**23.57**	**24.08**	**23.54**	**22.13**	**21.67**	**26.75**	**24.80**	**22.82**	**21.95**
Consumption by Sector									
Residential	4.87	4.93	4.89	4.80	4.78	4.96	4.87	4.78	4.74
Commercial	3.12	3.50	3.45	3.33	3.30	3.80	3.69	3.55	3.50
Industrial[6]	6.65	7.04	6.94	6.73	6.69	6.97	6.72	6.49	6.42
Electric Power[7]	6.66	6.72	6.28	5.45	5.16	8.74	7.42	6.12	5.53
Transportation[8]	0.04	0.12	0.11	0.11	0.10	0.23	0.19	0.17	0.17
Pipeline Fuel	0.63	0.64	0.70	0.67	0.64	0.76	0.72	0.69	0.65
Lease and Plant Fuel[9]	1.28	1.18	1.19	1.08	1.03	1.36	1.25	1.08	1.01
Total	**23.25**	**24.12**	**23.57**	**22.16**	**21.70**	**26.82**	**24.86**	**22.88**	**22.00**
Discrepancy[10]	**0.32**	**-0.04**	**-0.03**	**-0.03**	**-0.03**	**-0.07**	**-0.07**	**-0.06**	**-0.06**
Lower 48 End of Year Reserves	**235.63**	**258.77**	**259.77**	**252.42**	**241.11**	**264.39**	**267.94**	**261.33**	**244.95**

[1]Represents lower 48 onshore and offshore supplies.
[2]Marketed production (wet) minus extraction losses.
[3]Includes tight gas.
[4]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.
[5]Includes any natural gas regasified in the Bahamas and transported via pipeline to Florida.
[6]Includes energy for combined heat and power plants, except those whose primary business is to sell electricity, or electricity and heat, to the public.
[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 a vehicle fuel.
[9]Represents natural gas used in field gathering and 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, 2008 values include net storage injections.
Note: Totals may not equal sum of components due to independent rounding. Data for 2008 are model results and may differ slightly from official EIA data reports.
Sources: 2008 supply values: Energy Information Administration (EIA), *Natural Gas Monthly*, DOE/EIA-0130(2009/07) (Washington, DC, July 2009). 2008 consumption based on: EIA, *Annual Energy Review 2008*, DOE/EIA-0384(2008) (Washington, DC, June 2009). **Projections:** EIA, AEO2010 National Energy Modeling System runs HISHALE.D012210A, AEO2010R.D111809A, NOSHALE.D021110A, and NOLOPERM.D020510A.

Table D14. Natural Gas Supply and Disposition, Liquefied Natural Gas Supply Case
(Trillion Cubic Feet per Year, Unless Otherwise Noted)

Supply, Disposition, and Prices	2008	2015		2025		2035	
		Reference	High LNG	Reference	High LNG	Reference	High LNG
Dry Gas Production[1]	**20.56**	**19.29**	**18.88**	**21.31**	**18.54**	**23.27**	**21.23**
Lower 48 Onshore	17.56	16.09	15.75	15.96	15.15	17.07	15.41
Associated-Dissolved	1.39	1.44	1.43	1.25	1.25	1.03	1.04
Non-Associated	16.17	14.65	14.32	14.71	13.90	16.04	14.38
Conventional[2]	12.71	8.92	8.62	8.00	7.55	8.11	7.21
Unconventional	3.46	5.73	5.70	6.71	6.34	7.93	7.16
Gas Shale	1.49	3.85	3.88	4.94	4.69	6.00	5.49
Coalbed Methane	1.97	1.89	1.82	1.77	1.66	1.93	1.67
Lower 48 Offshore	2.62	2.91	2.84	3.46	3.11	4.33	3.95
Associated-Dissolved	0.55	0.79	0.79	0.90	0.86	1.00	0.97
Non-Associated	2.06	2.12	2.04	2.56	2.25	3.33	2.98
Alaska	0.38	0.29	0.29	1.88	0.28	1.87	1.87
Supplemental Natural Gas[3]	0.05	0.06	0.06	0.06	0.06	0.06	0.06
Net Imports	**2.95**	**2.38**	**3.34**	**2.17**	**5.54**	**1.46**	**5.25**
Pipeline[4]	2.65	1.29	1.38	0.89	1.23	0.64	1.09
Liquefied Natural Gas	0.30	1.09	1.96	1.28	4.31	0.83	4.16
Total Supply	**23.57**	**21.73**	**22.28**	**23.54**	**24.14**	**24.80**	**26.54**
Consumption by Sector							
Residential	4.87	4.71	4.74	4.89	4.96	4.87	4.97
Commercial	3.12	3.23	3.26	3.45	3.54	3.69	3.80
Industrial[5]	6.65	6.88	6.94	6.94	7.11	6.72	7.03
Electric Power[6]	6.66	5.18	5.65	6.28	6.80	7.42	8.72
Transportation[7]	0.04	0.05	0.05	0.11	0.12	0.19	0.22
Pipeline Fuel	0.63	0.60	0.60	0.70	0.61	0.72	0.71
Lease and Plant Fuel[8]	1.28	1.08	1.06	1.19	1.04	1.25	1.17
Total	**23.25**	**21.74**	**22.29**	**23.57**	**24.18**	**24.86**	**26.61**
Discrepancy[9]	**0.32**	**-0.01**	**-0.01**	**-0.03**	**-0.04**	**-0.07**	**-0.07**
Lower 48 End of Year Reserves	**235.63**	**254.61**	**254.41**	**259.77**	**252.44**	**267.94**	**257.68**
Natural Gas Prices							
(2008 dollars per million Btu)							
Henry Hub Spot Price	8.86	6.27	5.87	6.99	6.20	8.88	7.31
Average Lower 48 Wellhead Price[10]	7.85	5.54	5.19	6.18	5.48	7.84	6.46
(2008 dollars per thousand cubic feet)							
Average Lower 48 Wellhead Price[10]	8.07	5.70	5.33	6.35	5.63	8.06	6.64
Delivered Prices							
(2008 dollars per thousand cubic feet)							
Residential	13.87	11.89	11.50	12.65	11.94	14.82	13.36
Commercial	12.29	10.28	9.90	11.01	10.29	13.03	11.61
Industrial[5]	9.38	6.63	6.24	7.22	6.45	8.99	7.56
Electric Power[6]	9.34	6.24	5.90	6.94	6.23	8.69	7.37
Transportation[11]	16.42	13.76	13.39	13.82	13.15	15.21	13.79
Average[12]	**10.83**	**8.37**	**7.95**	**9.00**	**8.23**	**10.83**	**9.33**

[1]Marketed production (wet) minus extraction losses.
[2]Includes tight gas.
[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 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, 2008 values include net storage injections.
[10]Represents lower 48 onshore and offshore supplies.
[11]Compressed natural gas used as a vehicle fuel. Price includes estimated motor vehicle fuel taxes and estimated dispensing costs or charges.
[12]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 2008 are model results and may differ slightly from official EIA data reports.
Sources: 2008 supply values: Energy Information Administration (EIA), *Natural Gas Monthly*, DOE/EIA-0130(2009/07) (Washington, DC, July 2009). 2008 consumption based on: EIA, *Annual Energy Review 2008*, DOE/EIA-0384(2008) (Washington, DC, June 2009). **Projections:** EIA, AEO2010 National Energy Modeling System runs AEO2010R.D111809A and HILNG10.D112509A.

Table D15. Key Results for Heavy Truck Cases, Reference World Oil Price

Sales, Consumption, Supply, and Prices	2008	2015			2025			2035		
		Reference	2019 Phase Out	2027 Phase Out	Reference	2019 Phase Out	2027 Phase Out	Reference	2019 Phase Out	2027 Phase Out
Truck Sales by Size Class (millions)	**0.41**	**0.56**	**0.56**	**0.56**	**0.68**	**0.68**	**0.68**	**0.78**	**0.78**	**0.78**
Medium	0.21	0.30	0.30	0.30	0.37	0.37	0.37	0.46	0.46	0.46
Diesel	0.12	0.22	0.22	0.21	0.27	0.26	0.19	0.32	0.32	0.23
Motor Gasoline	0.08	0.08	0.08	0.08	0.09	0.09	0.07	0.11	0.11	0.09
Liquefied Petroleum Gases	0.00	0.00	0.00	0.00	0.01	0.01	0.01	0.01	0.01	0.01
Natural Gas	0.00	0.00	0.00	0.01	0.01	0.01	0.10	0.02	0.02	0.13
Heavy	0.21	0.26	0.26	0.26	0.30	0.30	0.30	0.32	0.32	0.32
Diesel	0.18	0.24	0.24	0.24	0.29	0.28	0.17	0.30	0.30	0.17
Motor Gasoline	0.03	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Liquefied Petroleum Gases	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Natural Gas	0.00	0.00	0.00	0.01	0.00	0.01	0.12	0.00	0.01	0.14
Consumption by Size Class (quadrillion Btu)	**4.72**	**4.93**	**4.93**	**4.93**	**5.58**	**5.58**	**5.62**	**6.46**	**6.46**	**6.54**
Medium	0.85	1.04	1.04	1.05	1.32	1.33	1.46	1.70	1.72	2.02
Diesel	0.59	0.76	0.76	0.76	0.99	0.99	0.93	1.27	1.27	1.12
Motor Gasoline	0.25	0.27	0.27	0.27	0.30	0.30	0.30	0.35	0.35	0.34
Liquefied Petroleum Gases	0.01	0.01	0.01	0.01	0.01	0.01	0.02	0.02	0.02	0.02
Natural Gas	0.01	0.00	0.01	0.01	0.02	0.03	0.21	0.05	0.07	0.54
Heavy	3.87	3.88	3.88	3.88	4.25	4.25	4.17	4.75	4.75	4.52
Diesel	3.75	3.80	3.80	3.78	4.18	4.15	3.64	4.67	4.62	3.44
Motor Gasoline	0.10	0.07	0.07	0.07	0.05	0.05	0.05	0.05	0.05	0.05
Liquefied Petroleum Gases	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Natural Gas	0.00	0.00	0.00	0.02	0.02	0.04	0.47	0.03	0.07	1.03
Natural Gas Prices (2008 dollars per thousand cubic feet)										
Wellhead[1]	8.07	5.70	5.71	5.72	6.35	6.34	6.58	8.06	8.12	8.38
Transportation Sector[1]	16.42	13.76	10.17	10.15	13.82	13.79	11.01	15.21	15.26	15.46
Average End Use[3]	10.83	8.37	8.37	8.38	9.00	9.00	9.27	10.83	10.91	11.45
Natural Gas Supply and Dispostion (trillion cubic feet)										
Dry Gas Production[4]	20.56	19.29	19.29	19.32	21.31	21.35	21.74	23.27	23.33	23.95
Supplemental Natural Gas[5]	0.05	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06
Net Imports	2.95	2.38	2.38	2.38	2.17	2.17	2.25	1.46	1.49	2.02
Consumption	23.25	21.74	21.75	21.77	23.57	23.63	24.11	24.86	24.97	26.12
Transportation	0.04	0.05	0.06	0.08	0.11	0.16	0.76	0.19	0.27	1.67
Petroleum Supply and Disposition (million barrels per day)										
Domestic Crude Oil Production[6]	4.96	5.77	5.76	5.76	6.13	6.12	6.11	6.27	6.28	6.29
Net Petroleum Imports	11.14	10.12	10.13	10.12	9.70	9.67	9.45	9.66	9.59	9.03
Other Petroleum Supply[7]	2.71	2.81	2.81	2.81	2.91	2.91	2.94	2.96	2.95	3.01
Other Non-petroleum Supply[8]	0.78	1.42	1.42	1.42	2.11	2.12	2.09	3.11	3.16	3.00
Consumption	19.53	20.18	20.17	20.17	20.99	20.96	20.71	22.06	22.04	21.37
Diesel	3.44	3.56	3.56	3.55	3.93	3.91	3.64	4.48	4.44	3.83
Diesel Fuel Price (2008 dollars per gallon)	3.79	3.14	3.15	3.15	3.65	3.66	3.60	4.11	4.12	3.93

[1]Represents lower 48 onshore and offshore supply.
[2]Natural gas used as a vehicle fuel. Price includes estimated motor vehicle fuel taxes and estimated dispensing costs or charges.
[3]Weighted average prices. Weights used are the sectoral consumption values excluding lease, plant, and pipeline fuel.
[4]Marketed production (wet) minus extraction losses.
[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.
[6]Includes lease condensate.
[7]Includes natural gas plant liquids, refinery processing gain, other crude oil supply, and stock withdrawals.
[8]Includes liquids, such as ethanol and biodiesel, derived from biomass, natural gas, and coal.
- - = Not applicable.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Data for 2008 are model results and may differ slightly from official EIA data reports.
Sources: 2008 data based on: Oak Ridge National Laboratory, *Transportation Energy Data Book: Edition 28 and Annual* (Oak Ridge, TN, 2009); U.S. Department of Commerce, Bureau of the Census, "Vehicle Inventory and Use Survey," EC02TV (Washington, DC, December 2004); Federal Highway Administration, *Highway Statistics 2007* (Washington, DC, October 2008); Energy Information Administration (EIA), *Annual Energy Review 2008*, DOE/EIA-0384(2008) (Washington, DC, June 2009); and EIA, AEO2010 National Energy Modeling System run AEO2010R.D111809A. **Projections:** EIA, AEO2010 National Energy Modeling System runs AEO2010R.D111809A, ATHNG80SNM19.D032510A, and ATHNG80S27.D033010A.

Table D16. Key Results for Heavy Truck Cases, Low World Oil Price

Sales, Consumption, Supply, and Prices	2008	2015			2025			2035		
		Low Price	2019 Phase Out	2027 Phase Out	Low Price	2019 Phase Out	2027 Phase Out	Low Price	2019 Phase Out	2027 Phase Out
Truck Sales by Size Class (millions)	**0.41**	**0.61**	**0.61**	**0.61**	**0.74**	**0.74**	**0.74**	**0.85**	**0.85**	**0.85**
Medium	0.21	0.32	0.32	0.32	0.40	0.40	0.40	0.48	0.48	0.48
Diesel	0.12	0.23	0.23	0.23	0.29	0.28	0.22	0.35	0.35	0.28
Motor Gasoline	0.08	0.09	0.09	0.09	0.10	0.10	0.08	0.12	0.12	0.10
Liquefied Petroleum Gases	0.00	0.00	0.00	0.00	0.01	0.01	0.01	0.01	0.01	0.01
Natural Gas	0.00	0.00	0.00	0.01	0.00	0.01	0.09	0.00	0.01	0.10
Heavy	0.21	0.28	0.28	0.28	0.34	0.34	0.34	0.37	0.37	0.37
Diesel	0.18	0.27	0.27	0.27	0.33	0.32	0.22	0.35	0.35	0.25
Motor Gasoline	0.03	0.01	0.01	0.01	0.01	0.01	0.01	0.02	0.01	0.01
Liquefied Petroleum Gases	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Natural Gas	0.00	0.00	0.00	0.01	0.00	0.01	0.11	0.00	0.01	0.11
Consumption by Size Class										
(quadrillion Btu)	**4.72**	**5.05**	**5.05**	**5.06**	**5.75**	**5.75**	**5.78**	**6.77**	**6.78**	**6.80**
Medium	0.85	1.06	1.06	1.06	1.35	1.36	1.45	1.76	1.77	1.96
Diesel	0.59	0.78	0.77	0.77	1.03	1.02	0.97	1.37	1.35	1.21
Motor Gasoline	0.25	0.27	0.27	0.27	0.30	0.30	0.30	0.37	0.37	0.35
Liquefied Petroleum Gases	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.02	0.02	0.02
Natural Gas	0.01	0.00	0.00	0.01	0.00	0.02	0.17	0.00	0.04	0.38
Heavy	3.87	4.00	4.00	3.99	4.40	4.39	4.33	5.02	5.01	4.84
Diesel	3.75	3.91	3.91	3.90	4.34	4.31	3.88	4.96	4.91	4.04
Motor Gasoline	0.10	0.07	0.07	0.07	0.05	0.05	0.05	0.05	0.05	0.05
Liquefied Petroleum Gases	0.01	0.01	0.01	0.01	0.00	0.00	0.00	0.01	0.01	0.01
Natural Gas	0.00	0.00	0.00	0.01	0.00	0.03	0.39	0.00	0.04	0.75
Natural Gas Prices										
(2008 dollars per thousand cubic feet)										
Wellhead[1]	8.07	5.08	5.08	5.09	6.25	6.26	6.36	7.38	7.44	7.57
Transportation Sector[1]	16.42	13.15	9.53	9.50	13.79	13.71	10.81	14.58	14.54	14.60
Average End Use[3]	10.83	7.66	7.66	7.67	8.87	8.89	9.02	10.09	10.17	10.51
Natural Gas Supply and Dispostion										
(trillion cubic feet)										
Dry Gas Production[4]	20.56	19.87	19.89	19.91	20.93	20.94	21.29	23.96	23.92	24.54
Supplemental Natural Gas[5]	0.05	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06
Net Imports	2.95	2.64	2.65	2.65	2.61	2.61	2.68	1.44	1.46	1.57
Consumption	23.25	22.58	22.61	22.64	23.61	23.64	24.07	25.49	25.48	26.21
Transportation	0.04	0.05	0.06	0.07	0.05	0.11	0.62	0.06	0.15	1.18
Petroleum Supply and Disposition										
(million barrels per day)										
Domestic Crude Oil Production[6]	4.96	5.56	5.55	5.57	4.95	4.95	4.95	4.37	4.38	4.38
Net Petroleum Imports	11.14	11.33	11.33	11.31	12.97	12.94	12.73	15.26	15.26	14.80
Other Petroleum Supply[7]	2.71	2.89	2.89	2.89	3.01	3.01	3.01	3.05	3.05	3.09
Other Non-petroleum Supply[8]	0.78	1.32	1.32	1.33	1.65	1.65	1.64	1.68	1.67	1.65
Consumption	19.53	21.19	21.18	21.17	22.69	22.65	22.44	24.54	24.54	24.07
Diesel	3.44	3.66	3.65	3.65	4.07	4.05	3.82	4.73	4.70	4.23
Diesel Fuel Price										
(2008 dollars per gallon)	3.79	2.16	2.15	2.15	2.17	2.17	2.13	2.20	2.18	2.11

[1]Represents lower 48 onshore and offshore supply.
[2]Natural gas used as a vehicle fuel. Price includes estimated motor vehicle fuel taxes and estimated dispensing costs or charges.
[3]Weighted average prices. Weights used are the sectoral consumption values excluding lease, plant, and pipeline fuel.
[4]Marketed production (wet) minus extraction losses.
[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.
[6]Includes lease condensate.
[7]Includes natural gas plant liquids, refinery processing gain, other crude oil supply, and stock withdrawals.
[8]Includes liquids, such as ethanol and biodiesel, derived from biomass, natural gas, and coal.
- - = Not applicable.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Data for 2008 are model results and may differ slightly from official EIA data reports.
Sources: 2008 data based on: Oak Ridge National Laboratory, *Transportation Energy Data Book: Edition 28 and Annual* (Oak Ridge, TN, 2009); U.S. Department of Commerce, Bureau of the Census, "Vehicle Inventory and Use Survey," EC02TV (Washington, DC, December 2004); Federal Highway Administration, *Highway Statistics 2007* (Washington, DC, October 2008); Energy Information Administration (EIA), *Annual Energy Review 2008*, DOE/EIA-0384(2008) (Washington, DC, June 2009); and EIA, AEO2010 National Energy Modeling System run AEO2010R.D111809A. **Projections:** EIA, AEO2010 National Energy Modeling System runs AEO2010R.D111809A, ATHNG80LPNM19.D032510A, and ATHNG80LP27.D033110A.

Table D17. Key Results for No Greenhouse Gas Concern Case
(Million Short Tons per Year, Unless Otherwise Noted)

Supply, Disposition, and Prices	2008	2015		2025		2035	
		Reference	No GHG Concern	Reference	No GHG Concern	Reference	No GHG Concern
Production[1]	**1172**	**1155**	**1157**	**1234**	**1262**	**1285**	**1423**
Appalachia	391	317	318	291	295	277	308
Interior	147	184	185	199	204	208	221
West	634	654	653	744	763	800	894
Waste Coal Supplied[2]	**14**	**16**	**16**	**15**	**15**	**15**	**16**
Net Imports[3]	**-49**	**-30**	**-30**	**-14**	**-12**	**20**	**20**
Total Supply[4]	**1136**	**1141**	**1143**	**1235**	**1266**	**1320**	**1458**
Consumption by Sector							
Residential and Commercial	4	3	3	3	3	3	3
Coke Plants	22	20	20	19	19	14	14
Other Industrial[5]	55	53	53	53	53	51	51
Coal-to-Liquids Heat and Power	0	11	12	24	37	37	78
Coal-to-Liquids Liquids Production	0	9	10	20	31	31	66
Electric Power[6]	1042	1044	1044	1116	1122	1183	1246
Total Coal Use	**1122**	**1141**	**1143**	**1235**	**1265**	**1319**	**1458**
Average Minemouth Price[7]							
(2008 dollars per short ton)	31.26	30.38	30.43	28.19	28.44	28.10	29.04
(2008 dollars per million Btu)	1.55	1.52	1.52	1.44	1.45	1.44	1.50
Delivered Prices[8]							
(2008 dollars per short ton)							
Coke Plants	118.09	132.98	133.01	137.06	137.01	132.10	132.91
Other Industrial[5]	63.44	57.43	57.51	56.11	56.71	57.88	59.51
Coal to Liquids	- -	20.14	20.39	21.22	22.53	22.34	23.87
Electric Power[6]							
(2008 dollars per short ton)	40.71	39.46	39.52	38.49	38.92	40.74	42.38
(2008 dollars per million Btu)	2.05	2.01	2.01	1.99	2.00	2.09	2.16
Average	**43.36**	**41.58**	**41.61**	**40.16**	**40.27**	**41.42**	**42.03**
Exports[9]	97.68	109.63	109.66	113.11	111.08	96.29	95.64
Cumulative Electricity Generating Capacity Additions (gigawatts)[10]							
Coal	0.0	17.2	17.3	20.4	27.3	30.6	64.8
Conventional	0.0	15.0	15.0	15.0	18.4	22.3	37.9
Advanced without Sequestration	0.0	0.6	0.6	0.6	2.6	2.1	16.4
Advanced with Sequestration	0.0	0.0	0.0	2.0	2.0	2.0	2.0
End-Use Generators[11]	0.0	1.6	1.7	2.8	4.3	4.2	8.5
Petroleum	0.0	0.3	0.3	0.3	0.3	0.3	0.3
Natural Gas	0.0	21.2	21.2	47.5	43.0	115.7	97.6
Nuclear	0.0	1.2	1.2	6.4	6.4	8.4	6.4
Renewables[12]	0.0	54.9	52.2	69.6	67.7	92.7	84.7
Other	0.0	1.9	1.9	1.8	1.8	1.9	1.9
Total	**0.0**	**96.7**	**94.0**	**146.0**	**146.5**	**249.5**	**255.7**
Liquids from Coal (million barrels per day)	0.00	0.07	0.08	0.15	0.25	0.24	0.52

[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, 2008. Includes all additions of electricity only and combined heat and power plants projected for the electric power, industrial, and commercial sectors.
[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.
[12]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.
GHG = Greenhouse gas.
Note: Totals may not equal sum of components due to independent rounding. Data for 2008 are model results and may differ slightly from official EIA data reports.
Sources: 2008 data based on: Energy Information Administration (EIA), *Annual Coal Report 2008*, DOE/EIA-0584(2008) (Washington, DC, September 2009); EIA, *Quarterly Coal Report, October-December 2008*, DOE/EIA-0121(2008/4Q) (Washington, DC, March 2009); and EIA, AEO2010 National Energy Modeling System run AEO2010R.D111809A.
Projections: EIA, AEO2010 National Energy Modeling System runs AEO2010R.D111809A and NORSK2010.D012510A.

Table D18. Key Results for Coal Cost Cases
(Million Short Tons per Year, Unless Otherwise Noted)

Supply, Disposition, and Prices	2008	2020			2035			Growth Rate, 2008-2035		
		Low Coal Cost	Reference	High Coal Cost	Low Coal Cost	Reference	High Coal Cost	Low Coal Cost	Reference	High Coal Cost
Production[1]	**1172**	**1235**	**1183**	**1143**	**1425**	**1285**	**1101**	**0.7%**	**0.3%**	**-0.2%**
Appalachia	391	322	305	293	300	277	288	-1.0%	-1.3%	-1.1%
Interior	147	188	198	216	159	208	274	0.3%	1.3%	2.3%
West	634	725	681	633	965	800	540	1.6%	0.9%	-0.6%
Waste Coal Supplied[2]	**14**	**15**	**15**	**15**	**9**	**15**	**27**	**-1.4%**	**0.3%**	**2.5%**
Net Imports[3]	**-49**	**-31**	**-15**	**-0**	**-25**	**20**	**70**	**-2.5%**	**- -**	**- -**
Total Supply[4]	**1136**	**1219**	**1183**	**1157**	**1409**	**1320**	**1199**	**0.8%**	**0.6%**	**0.2%**
Consumption by Sector										
Residential and Commercial	4	3	3	3	3	3	3	-0.2%	-0.2%	-0.2%
Coke Plants	22	21	20	20	14	14	14	-1.6%	-1.7%	-1.7%
Other Industrial[5]	55	54	53	53	51	51	50	-0.2%	-0.2%	-0.3%
Coal-to-Liquids Heat and Power	0	17	17	18	38	37	36	- -	- -	- -
Coal-to-Liquids Liquids Production	0	15	15	15	32	31	31	- -	- -	- -
Electric Power[6]	1042	1109	1073	1048	1270	1183	1065	0.7%	0.5%	0.1%
Total Coal Use	**1122**	**1219**	**1183**	**1157**	**1409**	**1319**	**1198**	**0.8%**	**0.6%**	**0.2%**
Average Minemouth Price[7]										
(2008 dollars per short ton)	31.26	23.11	30.01	39.25	13.30	28.10	61.33	-3.1%	-0.4%	2.5%
(2008 dollars per million Btu)	1.55	1.16	1.51	1.98	0.69	1.44	3.09	-3.0%	-0.3%	2.6%
Delivered Prices[8]										
(2008 dollars per short ton)										
Coke Plants	118.09	117.33	139.25	162.90	92.14	132.10	219.95	-0.9%	0.4%	2.3%
Other Industrial[5]	63.44	47.84	56.95	67.36	38.95	57.88	91.94	-1.8%	-0.3%	1.4%
Coal to Liquids	- -	15.57	20.37	26.45	12.13	22.34	43.17	- -	- -	- -
Electric Power[6]										
(2008 dollars per short ton)	40.71	31.58	38.90	48.72	24.77	40.74	73.07	-1.8%	0.0%	2.2%
(2008 dollars per million Btu)	2.05	1.61	1.98	2.48	1.28	2.09	3.65	-1.7%	0.1%	2.2%
Average	**43.36**	**33.33**	**40.95**	**50.96**	**25.33**	**41.42**	**73.87**	**-2.0%**	**-0.2%**	**2.0%**
Exports[9]	97.68	106.33	124.95	142.80	76.77	96.29	168.47	-0.9%	-0.1%	2.0%
Cumulative Electricity Generating Capacity Additions (gigawatts)[10]										
Coal	0.0	19.8	19.8	19.8	48.0	30.6	22.1	- -	- -	- -
Conventional	0.0	15.0	15.0	15.0	38.1	22.3	15.5	- -	- -	- -
Advanced without Sequestration	0.0	0.6	0.6	0.6	3.6	2.1	0.6	- -	- -	- -
Advanced with Sequestration	0.0	2.0	2.0	2.0	2.0	2.0	2.0	- -	- -	- -
End-Use Generators[11]	0.0	2.1	2.1	2.1	4.2	4.2	4.0			
Petroleum	0.0	0.3	0.3	0.3	0.3	0.3	0.3	- -	- -	- -
Natural Gas	0.0	26.1	26.2	26.0	109.9	115.7	115.5	- -	- -	- -
Nuclear	0.0	6.4	6.4	6.4	6.4	8.4	9.1	- -	- -	- -
Renewables[12]	0.0	62.7	60.0	56.7	88.5	92.7	89.3	- -	- -	- -
Other	0.0	1.8	1.8	1.8	1.9	1.9	1.9	- -	- -	- -
Total	**0.0**	**117.1**	**114.5**	**111.0**	**255.0**	**249.5**	**238.2**	**- -**	**- -**	**- -**
Liquids from Coal (million barrels per day)	0.00	0.11	0.11	0.11	0.24	0.24	0.23	- -	- -	- -

Table D18. Key Results for Coal Cost Cases (Continued)
(Million Short Tons per Year, Unless Otherwise Noted)

Supply, Disposition, and Prices	2008	2020			2035			Growth Rate, 2008-2035		
		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, 2008=1.000)										
Transportation Rate Multipliers										
Eastern Railroads	1.000	0.900	1.006	1.110	0.750	0.997	1.250	-1.1%	-0.0%	0.8%
Western Railroads	1.000	0.920	1.027	1.140	0.790	1.050	1.310	-0.9%	0.2%	1.0%
Mine Equipment Costs										
Underground	1.000	0.936	1.045	1.166	0.805	1.045	1.354	-0.8%	0.2%	1.1%
Surface	1.000	0.916	1.023	1.141	0.788	1.023	1.325	-0.9%	0.1%	1.0%
Other Mine Supply Costs										
East of the Mississippi: All Mines	1.000	0.843	0.942	1.051	0.673	0.873	1.131	-1.5%	-0.5%	0.5%
West of the Mississippi: Underground	1.000	0.843	0.942	1.051	0.673	0.873	1.131	-1.5%	-0.5%	0.5%
West of the Mississippi: Surface	1.000	0.843	0.942	1.051	0.673	0.873	1.131	-1.5%	-0.5%	0.5%
Coal Mining Labor Productivity (short tons per miner per hour)	5.96	8.23	6.10	4.46	13.85	6.51	2.63	3.2%	0.3%	-3.0%
Average Coal Miner Wage (2008 dollars per hour)	23.27	20.83	23.27	25.97	17.92	23.27	30.14	-1.0%	0.0%	1.0%

[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, 2008. Includes all additions of electricity only and combined heat and power plants projected for the electric power, industrial, and commercial sectors.
[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.
[12]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 2008 are model results and may differ slightly from official EIA data reports.
Sources: 2008 data based on: Energy Information Administration (EIA), *Annual Coal Report 2008*, DOE/EIA-0584(2008) (Washington, DC, September 2009); EIA, *Quarterly Coal Report, October-December 2008*, DOE/EIA-0121(2008/4Q) (Washington, DC, March 2009); U.S. Department of Labor, Bureau of Labor Statistics, Average Hourly Earnings of Production Workers: Coal Mining, Series ID : ceu1021210008; and EIA, AEO2010 National Energy Modeling System run AEO2010R.D111809A. **Projections:** EIA, AEO2010 National Energy Modeling System runs LCCST10.D120909A, AEO2010R.D111809A, and HCCST10.D120909A.

NEMS Overview and Brief Description of Cases

The National Energy Modeling System

Projections in the *Annual Energy Outlook 2010* (*AEO2010*) are generated from the National Energy Modeling System (NEMS) [*1*], developed and maintained by the Office of Integrated Analysis and Forecasting (OIAF) of the U.S. 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 2035, approximately 25 years into the future. In order to represent regional differences in energy markets, the component modules of NEMS function at the regional level: the nine Census divisions for the end-use demand modules; production regions specific to oil, 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 (see Appendix F for details).

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 liquids 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 *AEO2010* represents current legislation and environmental regulations as of October 31, 2009 (such as the American Recovery and Reinvestment Act of 2009 [ARRA], which was enacted in mid-February 2009; the Energy Improvement and Extension Act of 2008 [EIEA2008], signed into law on October 3, 2008; the Food, Conservation, and Energy Act of 2008; 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). The *AEO2010* models do not represent the Clean Air Mercury Rule, 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 *AEO2010* Reference case reflects the temporary reinstatement of the NO_x and SO_2 cap-and-trade programs included in the Clean Air Interstate Rule

(CAIR), according to the ruling issued by the U.S. Court of Appeals for the District of Columbia on December 23, 2008. The potential impacts of 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 *AEO2010* projections are based on EIA's *Annual Energy Review 2008*, published in June 2009 [*2*]; however, data were taken from multiple sources. In some cases, only partial or preliminary data were available for 2008. CO_2 emissions were calculated by using CO_2 coefficients from the EIA report, *Emissions of Greenhouse Gases in the United States 2008*, published in December 2009 [*3*]. Historical numbers are presented for comparison only and may be estimates. Source documents should be consulted for the official data values. Footnotes to the *AEO2010* appendix tables indicate the definitions and sources of historical data.

The *AEO2010* projections for 2009 and 2010 incorporate short-term projections from EIA's September 2009 *Short-Term Energy Outlook* (*STEO*). For short-term energy projections, readers are referred to monthly updates of the *STEO* [*4*].

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 receives energy-related indicators from the NEMS energy components as part of the 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. Key energy indicators fed back to the MAM include aggregate energy prices and costs. 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 Energy Module (IEM) uses assumptions of economic growth and expectations of future U.S. and world petroleum liquids production and consumption, by year, to project the interaction of U.S. and international liquids markets. The IEM computes world oil prices, provides a world crude-like liquids supply curve, generates a worldwide oil supply/demand balance for each year of the projection period, and computes initial estimates of crude oil and light and heavy petroleum product imports for the United States.

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. In the interaction with the rest of NEMS, the IEM changes the world oil price (WOP), which is defined as the price of foreign light, low sulfur crude oil delivered to Cushing, Oklahoma, (Petroleum Allocation Defense District 2), in response to changes in expected crude and product liquids produced and consumed in the United States.

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 and cost 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 recent regional standards for furnaces, heat pumps, and central air conditioners agreed to by manufacturers and environmental interest groups. 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, feedstocks, and raw materials in each of 21 industries, subject to the delivered prices of energy and the values of 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 energy-consuming components for boiler/steam/cogeneration, buildings, and process/assembly use of energy.

A new bulk chemical model was implemented for the *AEO2010*. The new model calculates the production (in physical units), process shares, and process energy requirements for 26 specific chemicals and four aggregate groups of bulk chemicals. Details are included in the forthcoming Industrial Demand Module documentation. A generalized representation of CHP and a recycling component also are included. The use of energy for petroleum refining is modeled in the Petroleum Market Module (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 other legislation and legislative proposals specific to those market segments. The Transportation Demand Module also includes a component to assess the penetration of alternative-fuel vehicles. Provisions of EPACT2005, EIEA2008, and ARRA are reflected in the assessment of the impacts of tax credits on the purchase of hybrid gas-electric, plug-in 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), the EPA, 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 [*5*]. 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

There are three primary submodules of the Electricity Market Module—capacity planning, fuel dispatching, and finance and pricing. To project the optimal mix of new generation capacity that should be added in future years, the Capacity Planning Submodule uses the stock of existing generation capacity; the menu, cost, and performance of future generation capacity; expected fuel prices; expected financial parameters; expected electricity demand; and expected environmental regulations. The Fuel Dispatching Submodule uses the existing stock of generation equipment, their operating and maintenance (O&M) costs and performance, fuel prices to the electricity sector, electricity demand, and all applicable environmental regulations to determine the least-cost way to meet that demand; the submodule also projects transmission and pricing of electricity. The Finance and Pricing Submodule uses capital costs, fuel costs, macroeconomic parameters, and environmental regulations, along with load shapes, to estimate generation costs for each technology.

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 *AEO2010*. The *AEO2010* Reference case reflects the temporary reinstatement of the NO_x and SO_2 cap-and-trade programs included in CAIR, as well as State regulations on mercury emissions.

Although currently there is no Federal legislation in place that restricts greenhouse gas (GHG) emissions, regulators and the investment community have continued to push energy companies to invest in technologies that are less GHG-intensive. The trend is captured in the *AEO2010* Reference case through a 3-percentage-point increase in the cost of capital when investments in new coal-fired power plants and new coal-to-liquids (CTL) plants without carbon capture and sequestration (CCS) 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, 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 EIEA-2008.

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 2.1 cents per kilowatthour for electricity produced in the first 10 years of plant operation. For *AEO2010*, new wind plants coming on line before January 1, 2013, are eligible to receive the PTC; other eligible plants must be in service before January 1, 2014. As part of ARRA, plants eligible for the PTC may instead elect to receive a 30-percent ITC or an equivalent direct grant. *AEO2010* 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 2010* [*6*].

Oil and Gas Supply Module

The Oil and Gas Supply Module (OGSM) 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 all production 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 6 onshore, 3 offshore and 3 Alaskan regions.

The *AEO2010* OGSM includes a revised representation of onshore oil and gas supply, the new Onshore Lower 48 Oil and Gas Supply Submodule (OLOGSS), which evaluates the economics of future exploration and development projects for crude oil and natural gas at the play level. Crude oil resources are divided into known plays and undiscovered plays, and include highly fractured continuous zones, such as the Austin chalk and Bakken shale formations. Production potential from advanced secondary recovery techniques (e.g., in-fill drilling, horizontal continuity, and horizontal profile) and enhanced oil recovery (e.g., CO_2 flooding, steam flooding, polymer flooding, and profile modification) are explicitly represented. Natural gas resources are divided into known producing plays, known developing plays, and undiscovered plays in high-permeability carbonate and sandstone, tight gas, shale gas, and coalbed formations.

Domestic 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 wellhead prices and domestic production.

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, the potential for converting coal to pipeline-quality 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 and destinations of natural gas, including pipeline imports and exports (Canada and Mexico) and liquefied natural gas (LNG) imports and exports. For *AEO2010*, an algorithm was added to project the addition of compressed natural gas retail fueling capability.

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.

The PMM in NEMS 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 renewable fuels standard (RFS) in EISA2007, which requires the use of 36 billion ethanol-equivalent gallons per year of biofuels by 2022 if achievable, with corn ethanol credits limited to 15 billion gallons per year [*7*]. Demand growth and regulatory changes necessitate capacity expansion for refinery processing units. U.S. end-use prices for petroleum products 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. Additional detailed information on the PMM can be found in *Assumptions to the Annual Energy Outlook 2010* [*9*].

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 use in flex-fuel vehicles. Although blending into gasoline at 15 percent or less by volume (E15) is currently being considered for certification by the EPA as a viable motor fuel, its use in LDVs has not been approved and thus is not modeled for *AEO2010*. In addition, the model reflects the allowable level of non-E85 ethanol blending in California, which has been raised from 5.7 percent to 10 percent in recent regulatory changes that have set a framework for E10 emissions standards starting in year 2010 [*10*].

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, poplar, and crop residues. Biodiesel (diesel-like fuel made in a transesterification 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 or tallow 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 EISA2007 RFS. Domestic ethanol production from three feedstock categories (corn, cellulosic, and advanced) is modeled. Corn-based ethanol plants are numerous (more than 180 are now in operation, with a total operating production capacity of more than 11 billion gallons annually) and are based on a well-known technology that converts starch and sugar into ethanol. Ethanol from cellulosic sources is a new technology, with only a few small pilot plants in operation. Large-scale commercialization of the cellulosic technology is not expected to ramp up quickly enough to meet the cellulosic ethanol mandate in EISA2007.

DOE and the U.S. Department of Agriculture (USDA) have awarded numerous grants to biorefinery projects (over $600 million in 2009 alone), and the USDA has provided a loan guarantee to a small commercial-sized cellulosic biofuel plant scheduled to begin production next year; however, reduced investment during the recent recession is expected to cause significant delays in the startup of large commercial plants, and the delays are reflected in the projections. Imported ethanol can be produced from cane sugar or from bagasse (the cellulosic byproduct of sugar milling). For *AEO2010*, assumptions about ethanol import availability have been reviewed and updated from the previous Reference case, to reflect greater expected availability of ethanol from sugar cane. The sources of ethanol are modeled to compete on an economic basis.

Fuels produced by gasification and Fischer-Tropsch synthesis, or through a pyrolysis process, also are modeled in the PMM, based on their economics relative to competing feedstocks and products. The four processes modeled are CTL, gas-to-liquids (GTL), BTL, and pyrolysis. 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. In addition, a hybrid coal-biomass-to-liquids process was implemented for *AEO2010*. GTL facilities may be built in Alaska, but they would compete with the Alaska Natural Gas Transportation System for available natural gas resources. BTL and pyrolysis 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 requirement for cellulosic biofuels.

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 demand by 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 16 demand regions.

Annual Energy Outlook 2010 cases

Table E1 provides a summary of the cases produced as part of *AEO2010*. 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 2010* [*11*]. 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 *AEO2010* 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:

Table E1. Summary of the *AEO2010* cases

Case name	Description	Integration mode	Reference in text	Reference in Appendix E
Reference	Baseline economic growth (2.4 percent per year from 2008 through 2035), 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 2008 to 2035. Other energy market assumptions are the same as in the Reference case. Partial projection tables in Appendix B.	Fully integrated	p. 52	p. 204
High Economic Growth	Real GDP grows at an average annual rate of 3.0 percent from 2008 to 2035. Other energy market assumptions are the same as in the Reference case. Partial projection tables in Appendix B.	Fully integrated	p. 52	p. 204
Low Oil Price	More optimistic assumptions for economic access to non-OPEC resources and for OPEC behavior than in the Reference case. World light, sweet crude oil prices are $51 per barrel in 2035, compared with $133 per barrel in the Reference case (2008 dollars). Other assumptions are the same as in the Reference case. Partial projection tables in Appendix C.	Fully integrated	p. 54	p. 205
High Oil Price	More pessimistic assumptions for economic access to non-OPEC resources and for OPEC behavior than in the Reference case. World light, sweet crude oil prices are about $210 per barrel (2008 dollars) in 2035. Other assumptions are the same as in the Reference case. Partial projection tables in Appendix C.	Fully integrated	p. 54	p. 205
Extended Policies	Begins with the Reference case and selectively extends PTC, ITC, and other energy efficiency tax credit policies with sunset provisions, and promulgates new efficiency standards as they satisfy the consumer-related cost-effectiveness criteria of DOE's Office of Energy Efficiency and Renewable Energy. Introduces new CAFE and tailpipe emissions proposal. Partial projection tables in Appendix D.	Fully integrated	p. 22	p. 210
No Sunset	Begins with the Reference case and extends all energy policies and legislation with sunset provisions, except those requiring additional funding (e.g., loan guarantee programs). Also extends the RFS requirement to 36 billion gallons by 2026 and continues increasing proportional to transport demand thereafter. Partial projection tables in Appendix D.	Fully integrated	p. 22	p. 210
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. 31	p. 205
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. Consumers evaluate efficiency investments at a 7-percent real discount rate. Partial projection tables in Appendix D.	With commercial	p. 31	p. 205
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. 31	p. 205

Table E1. Summary of the *AEO2010* cases (continued)

Case name	Description	Integration mode	Reference in text	Reference in Appendix E
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. 31	p. 205
Commercial: High Technology	Earlier availability, lower costs, and higher efficiencies for more advanced equipment. Energy efficiency investments evaluated at a 7-percent real discount rate. Building shell efficiencies for new and existing buildings increase by 17.4 and 7.5 percent, respectively, from 2003 values by 2035. Partial projection tables in Appendix D.	With residential	p. 31	p. 205
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 20.8 and 9.0 percent, respectively, from 2003 values by 2035. Partial projection tables in Appendix D.	With residential	p. 31	p. 205
Industrial: 2010 Technology	Efficiency of plant and equipment fixed at 2010 levels. Partial projection tables in Appendix D.	Standalone	p. 176	p. 206
Industrial: High Technology	Earlier availability, lower costs, and higher efficiencies for more advanced equipment. Partial projection tables in Appendix D.	Standalone	p. 176	p. 206
Transportation: Low Technology	Advanced technologies are more costly and less efficient than in the Reference case. Partial projection tables in Appendix D.	Standalone	p. 64	p. 206
Transportation: High Technology	Advanced technologies are less costly and more efficient than in the Reference case. Partial projection tables in Appendix D.	Standalone	p. 64	p. 206
Transportation: Reference Case 2019 Phaseout With Base Market Potential	Modified Reference case incorporating lower incremental costs for all classes of heavy-duty natural gas vehicles and tax incentives for natural gas refueling stations and natural gas fuel beginning in 2011 and phased out by 2019. Partial projection tables in Appendix D.	Fully integrated	p. 34	p. 206
Transportation: Reference Case 2027 Phaseout With Expanded Market Potential	Modified Reference case incorporating lower incremental costs for all classes of heavy-duty natural gas vehicles and tax incentives for natural gas refueling stations and natural gas fuel beginning in 2011 and phased out by 2027, with assumed increases in the potential market for all classes of heavy-duty natural gas vehicles. Partial projection tables in Appendix D.	Fully integrated	p. 35	p. 207
Transportation: Low Oil Price Case 2019 Phaseout With Base Market Potential	Modified Low Oil Price case incorporating lower incremental costs for all classes of heavy-duty natural gas vehicles and tax incentives for natural gas refueling stations and natural gas fuel beginning in 2011 and phased out by 2019. Partial projection tables in Appendix D.	Fully integrated	p. 35	p. 207
Transportation: Low Oil Price Case 2027 Phaseout With Expanded Market Potential	Modified Low Oil Price case incorporating lower incremental costs for all classes of heavy-duty natural gas vehicles and tax incentives for natural gas refueling stations and natural gas fuel beginning in 2011 and phased out by 2027, with assumed increases in the potential market for all classes of heavy-duty natural gas vehicles. Partial projection tables in Appendix D.	Fully integrated	p. 35	p. 207
Electricity: Low Fossil Technology Cost	Capital and operating costs for all new fossil-fired generating technologies start 10 percent below the Reference case and decline to 25 percent below the Reference case in 2035. Partial projection tables in Appendix D.	Fully integrated	p. 181	p. 207
Electricity: High Fossil Technology Cost	Costs for new advanced fossil-fired generating technologies do not improve due to learning over time from 2010. Partial projection tables in Appendix D.	Fully integrated	p. 181	p. 207

Table E1. Summary of the *AEO2010* cases (continued)

Case name	Description	Integration mode	Reference in text	Reference in Appendix E
Electricity: Low Nuclear Cost	Capital and operating costs for new nuclear capacity start 10 percent below the Reference case and decline to 25 percent below the Reference case in 2035. Partial projection tables in Appendix D.	Fully integrated	p. 179	p. 207
Electricity: High Nuclear Cost	Costs for new nuclear technology do not improve due to learning from 2010 levels in the Reference case. Partial projection tables in Appendix D.	Fully integrated	p. 179	p. 207
Electricity: Nuclear 60-Year Life	All existing nuclear plants are retired after 60 years of operation. Partial projection tables in Appendix D.	Fully integrated	p. 43	p. 208
Renewable Fuels: Low Renewable Technology Cost	Levelized cost of energy for nonhydropower renewable generating technologies start 10 percent below the Reference case in 2010 and decline to 25 percent below the Reference case in 2035. Partial projection tables in Appendix D.	Fully integrated	p. 69	p. 208
Renewable Fuels: High Renewable Technology Cost	New renewable generating technologies do not improve through learning over time from 2010. Partial projection tables in Appendix D.	Fully integrated	p. 69	p. 208
Oil and Gas: Slow Technology	Improvements in exploration and development costs, production rates, and success rates due to technological advancement are reduced by 50 percent to reflect slower improvement than in the Reference case. Partial projection tables in Appendix D.	Fully integrated	p. 71	p. 208
Oil and Gas: Rapid Technology	Improvements in exploration and development costs, production rates, and success rates due to technological advancement are increased by 50 percent to reflect more rapid improvement than in the Reference case. Partial projection tables in Appendix D.	Fully integrated	p. 71	p. 208
Oil and Gas: No Low-Permeability Gas Drilling	No drilling is permitted in onshore, lower 48 low-permeability natural gas reservoirs after 2009 (i.e., no new tight gas or shale gas drilling). Partial projection tables in Appendix D.	Fully integrated	p. 41	p. 209
Oil and Gas: No Shale Gas Drilling	No drilling is permitted in onshore, lower 48 shale gas reservoirs after 2009 (i.e., no new shale gas drilling). Partial projection tables in Appendix D.	Fully integrated	p. 41	p. 209
Oil and Gas: High Shale Gas Resource	Shale gas resources in the onshore, lower 48 are assumed to be higher than in the Reference case. Partial projection tables in Appendix D.	Fully integrated	p. 41	p. 209
Oil and Gas: High LNG Supply	LNG imports into North America are set exogenously to a factor times the levels projected in the Reference case from 2010 forward. The factor starts at 1.0 in 2010 and increases linearly to 5.0 in 2035. Partial projection tables in Appendix D.	Fully integrated	p. 74	p. 208
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. 80	p. 209
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. 80	p. 209

Table E1. Summary of the *AEO2010* cases (continued)

Case name	Description	Integration mode	Reference in text	Reference in Appendix E
Integrated Low Technology	Combination of the Residential, Commercial, and Industrial 2010 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. 32	p. 209
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. 32	p. 209
No GHG Concern	No GHG emissions reduction policy is enacted, and market investment decisions are not altered in anticipation of such a policy.	Fully integrated	p. 81	p. 209

- In the Reference case, population grows by 0.9 percent per year, nonfarm employment by 0.8 percent per year, and labor productivity by 2.0 percent per year from 2008 to 2035. Economic output as measured by real GDP increases by 2.4 percent per year from 2008 through 2035, and growth in real disposable income per capita averages 1.8 percent per year.
- The *Low Economic Growth case* assumes lower growth rates for population (0.5 percent per year) and labor productivity (1.5 percent per year), resulting in lower nonfarm employment (0.4 percent per year), 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 2008 through 2035, and growth in real disposable income per capita averages 1.7 percent per year.
- The *High Economic Growth case* assumes higher growth rates for population (1.3 percent per year) and labor productivity (2.4 percent per year), resulting in higher nonfarm employment (1.2 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 (2.4 percent). Disposable income per capita grows by 1.82 percent per year, compared with 1.8 percent in the Reference case.

Oil price cases

The world oil price in *AEO2010* 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. *AEO2010* 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 domestic 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. *AEO2010* 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 $70 per barrel (2008 dollars) in 2010 to $95 per barrel in 2015, then increase more slowly to $133 per barrel in 2035. The Reference case represents EIA's current best 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 $51 per barrel (2008 dollars) in 2035, compared with $133 per barrel in the Reference case. The Low Oil Price case assumes that OPEC countries will increase their conventional oil production to obtain a 47-percent share of total world liquids production, and that oil resources outside the United States 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 the United States 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 $210 per barrel (2008 dollars) in 2035. 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 *AEO2010* 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 [*12*]. For new construction, building shell efficiencies are assumed to meet ENERGY STAR requirements after 2016. Consumers evaluate investments in energy efficiency at a 7-percent real discount rate.
- 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 [*13*]. Energy efficiency investments are evaluated at a 7-percent real discount rate. Building shell efficiencies for new and existing buildings in 2035 are assumed to be 17.4 percent and 7.5 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 2035 are assumed to be 20.8 percent and 9.0 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 (see "Renewable Fuels Cases"). 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 that are 10 percent below Reference case assumptions in 2010 and decline to at least 25 percent below Reference case costs in 2035.

- 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 2035.

Industrial sector cases

In addition to the *AEO2010* 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 PMM.) The Industrial Demand Module also was used as part of the Integrated Low and High Renewable Technology Cost cases. For the industrial sector:

- The *2010 Technology case* holds the energy efficiency of plant and equipment constant at the 2010 level over the projection period. In this case, delivered energy intensity falls by 0.7 percent annually from 2008 to 2035, as compared with 1.1 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, 2010 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 [*14*] 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 1.2 percent annually in the High Technology case.

The 2010 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 *AEO2010* 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 [*15*]. 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 also are reflected in the rail and shipping sectors.

- In the *High Technology case*, the characteristics of conventional and alternative-fuel LDVs 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 also are 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 vehicle costs or travel demand was captured, nor were changes in fuel prices incorporated.

- The *Reference Case 2019 Phaseout With Base Market Potential case* is a modified Reference case that incorporates lower incremental costs for all classes of heavy-duty natural gas vehicles (zero incremental cost relative to their diesel-powered counterparts after accounting for incentives) and tax incentives for natural gas refueling stations ($100,000 per new facility) and for natural gas fuel ($0.50 per gallon of gasoline equivalent) that begin in 2011 and are phased out by 2019.

- The *Reference Case 2027 Phaseout With Expanded Market Potential case* is a modified Reference case with the same added assumptions of lower incremental costs for heavy-duty natural gas vehicles and subsidies for fueling stations and natural gas fuel as in the Reference Case 2019 Phaseout With Base Market Potential case but with the subsidies extended to 2027 before phaseout and, in addition, assumed increases in the potential market for both "fleet" and "non-fleet" natural gas vehicles.

- The *Low Oil Price Case 2019 Phaseout With Base Market Potential case* is a modified Low Oil Price case that incorporates lower incremental costs for all classes of heavy-duty natural gas vehicles (zero incremental cost relative to their diesel-powered counterparts after accounting for incentives) and tax incentives for natural gas refueling stations ($100,000 per new facility) and for natural gas fuel ($0.50 per gallon of gasoline equivalent) that begin in 2011 and are phased out by 2019.
- The *Low Oil Price Case 2027 Phaseout With Expanded Market Potential case* is a modified Low Oil Price case with the same added assumptions of lower incremental costs for heavy-duty natural gas vehicles and subsidies for fueling stations and natural gas fuel as in the Reference Case 2019 Phaseout With Base Market Potential case but with the subsidies extended to 2027 before phaseout and, in addition, assumed increases in the potential market for both "fleet" and "non-fleet" natural gas vehicles.

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. 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.

In addition, for *AEO2010* an alternate retirement case was run for nuclear power plants, to address uncertainties about the operating lives of existing reactors. This scenario is discussed in the Issues in Focus article, "U.S. nuclear power plants: Continued life or replacement after 60?"

Nuclear technology cost cases

- The cost assumptions for the *Low Nuclear Cost case* reflect an approximate 10-percent reduction in capital and operating costs for advanced nuclear technology in 2010, relative to the Reference case, and fall to 25 percent below the Reference case in 2035. The Reference case projects a 35-percent reduction in the capital costs of nuclear power plants from 2010 to 2035; the Low Nuclear Cost case assumes a 45-percent reduction from 2010 to 2035.
- The *High Nuclear Cost case* assumes that capital costs for advanced nuclear technology remain fixed at the 2010 levels assumed in the Reference case. The capital costs still are tied to key commodity price indices, so they change over time; however, no cost improvement from "learning-by-doing" effects is assumed.

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 start 10 percent lower than Reference case levels and fall to 25 percent lower than Reference case levels in 2035. Because learning in the Reference case reduces costs with manufacturing experience, costs in the Low Fossil Cost case are reduced by 37 to 49 percent between 2010 and 2035, depending on the technology.
- In the *High Fossil Technology Cost case*, capital costs for all coal- and natural-gas-fired generating technologies remain fixed at the 2010 values assumed in the Reference case. Costs still are adjusted year to year by the commodity price index, but no learning-related cost reductions are assumed.

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 2010* [*16*].

Alternative Nuclear Retirement Case

- In the *Nuclear 60-Year Life case*, all existing nuclear plants are assumed to retire after 60 years of operation. In the Reference case, existing plants are assumed to run as long as they continue to be economic, implicitly assuming that a second 20-year license renewal will be obtained for those plants reaching 60 years before 2035. This case was run to analyze the impact of additional nuclear retirements, which could occur if the oldest plants do not receive a second license extension. In this case, 31 gigawatts of nuclear capacity is assumed to be retired by 2035.

Renewable fuels cases

In addition to the *AEO2010* 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, O&M costs, and performance levels for wind, solar, biomass, and geothermal resources are assumed to remain constant at 2010 levels through 2035. Costs still are tied to key commodity price indexes, but no cost improvement from "learning-by-doing" effects is assumed. 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 start at 10 percent below Reference case levels in 2010 and decline to 25 percent below the Reference case costs for the same resources in 2035. 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 also is increased.

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 is examined in three cases:

- In the *Rapid Technology case*, the parameters representing the effects of technological progress on production rates, exploration and development costs, and success rates for oil and natural gas drilling in the Reference case are improved by 50 percent. Key supply parameters for Canadian natural gas also are modified to simulate the assumed impacts of more rapid 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 2010* [*17*].
- In the *Slow Technology case*, the parameters representing the effects of technological progress on production rates, exploration and development costs, and success rates for oil and natural gas drilling are 50 percent less optimistic than those in the Reference case. Key Canadian supply parameters also are modified to simulate the assumed impacts of slow 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 North American LNG import levels for 2010 through 2030 as being equal to a factor times the Reference case levels. The factor starts at 1 in 2010 and increases linearly to 5 in 2035. 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.

Three additional cases examine the importance of low-permeability reservoirs on future domestic natural gas supply:

- In the *No Low-Permeability Drilling case*, no new onshore, lower 48 wells are drilled in low permeability natural gas reservoirs (includes shale gas and tight sandstone gas) after 2009. Natural gas production from low-permeability wells drilled before 2010 declines continuously through 2035.
- In the *No Shale Gas Drilling case*, no new onshore, lower 48 shale gas wells are drilled after 2009. Natural gas production from shale gas wells

drilled before 2010 declines continuously through 2035.

- In the *High Shale Gas Resource case*, the resource base for shale gas in the onshore, lower 48 States is assumed to be higher than in the Reference case. Each well can support twice as many shale gas plays as in the Reference case, increasing the resource base from 347 trillion cubic feet in the Reference case to 652 trillion cubic feet in the High Shale Gas Resource case. The estimated recovery from each well is the same as 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 2035. 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 2.7 percent observed since 2000. Transportation rates are lowered (in the Low Coal Cost case) or raised (in the High Coal Cost case) from Reference case levels to achieve a 25-percent change in rates relative to the Reference case in 2035. 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 2035 to 2.2 percent in the Low Coal Cost case. Coal mining wages, mine equipment costs, and other mine supply costs all are assumed to be about 25 percent lower in 2035 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 2035.

- 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 2035 are assumed to be about 30 percent higher than in the Reference case, and coal transportation rates in 2035 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 *AEO2010* 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, a No GHG Concern case was run that excludes the 3-percent cost-of-capital adjustment for new coal-fired generating capacity and for CTL plants without CCS. In the Reference case, this adjustment is included to simulate the reluctance of regulators and the investment community to invest in GHG-intensive technologies, given uncertainty about the possible enactment of limits on GHG emissions.

Integrated technology cases

The *Integrated Low Technology case* combines the assumptions from the residential, commercial, and industrial 2010 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.

Extended Policies case

In addition to the *AEO2010* Reference case, an additional case was run assuming that selected policies with sunset provisions (such as the PTC, ITC, and tax credits for energy-efficient equipment in the buildings sector) will be extended indefinitely rather than allowed to sunset as the law currently prescribes. Further, updates to Federal appliance efficiency standards were assumed to occur at intervals provided by law and at levels determined by the consumer impact test in DOE testing procedures or Federal Energy Management Program (FEMP) purchasing guidelines. Finally, proposed rules by NHTSA and the EPA for national tailpipe CO_2-equivalent emissions and fuel economy standards for LDVs, including both passenger cars and light-duty trucks, were harmonized and incorporated in this case.

In the electricity market, tax credits for renewable generation capacity that are available currently but are scheduled to expire are instead assumed to be extended indefinitely—including the PTC of 2.1 cents per kilowatthour or, as appropriate, the 30-percent ITC available for wind, geothermal, biomass, hydroelectric, and landfill gas resources. For solar capacity, a 30-percent ITC that is scheduled to revert to a 10-percent tax credit in 2016 is, instead, assumed to be extended indefinitely at 30 percent.

In the buildings sector, tax credits for the purchase of energy-efficient equipment, including PV and new houses, are extended indefinitely, as opposed to ending in 2010 or 2016 as prescribed by current law. The business ITCs for commercial-sector generation technologies and geothermal heat pumps are extended indefinitely, as opposed to expiring in 2016, and the business ITC for solar systems is kept at 30 percent instead of reverting to 10 percent. In addition, updates to appliance standards are assumed to occur as prescribed by the timeline in DOE's multiyear plan. The efficiency levels chosen for the updated standard were based on the technology menu in the *AEO2010* Reference case and whether or not the efficiency level passed the consumer impact test prescribed in DOE's standards-setting process. The efficiency levels chosen for updated commercial equipment standards are based on the technology menu from the *AEO2010* Reference case and FEMP-designated purchasing specifications for Federal agencies.

NHTSA and the EPA have proposed rules for coordinated national CO_2-equivalent tailpipe emissions and fuel economy standards for LDVs, including both passenger cars and light-duty trucks. The harmonized fuel economy standards begin in model year (MY) 2012 and increase in stringency to MY 2016, based on NHTSA's recently proposed CAFE standards. NHTSA has estimated the impact of the new CAFE standards and has projected that the proposed fleet-wide standards for LDVs will increase fuel economy from 27.3 miles per gallon in MY 2011 to 34.1 miles per gallon in MY 2016, based on projected sales of vehicles by type and footprint. Separate mathematical functions representing the CAFE standards are established for passenger cars and light trucks, reflecting their different design capabilities. As required by EISA2007, the fuel economy standards increase to 35 miles per gallon by 2020. The Extended Policies case assumes that these standards are further increased so that the minimum fuel economy standard achieved for LDVs increases to 45.6 miles per gallon in 2035.

No Sunset case

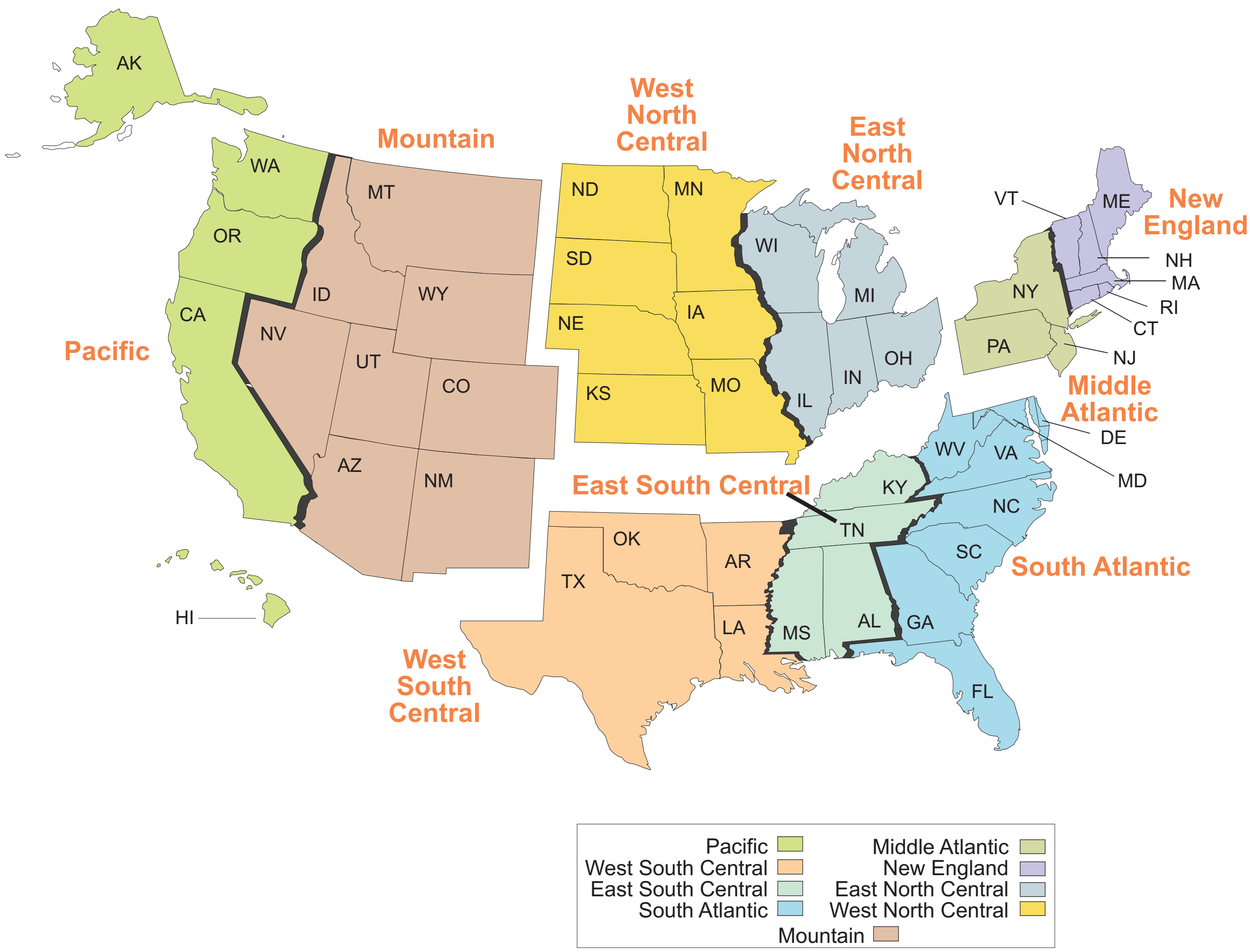
Assumptions for extensions of the renewable energy tax credit and the buildings tax credit are the same as in the Extended Policies case described above. No updates to appliance or CAFE standards are assumed. This case also extends the RFS target to that originally set by law (36 billion ethanol-equivalent gallons) and assumes that the target is achieved by 2026 instead of 2022; after 2026, the RFS requirement continues to increase so that it remains at the same percentage of total transport fuel demand as achieved in 2026. Biofuel tax credits and the import tariffs also are extended.

Endnotes

1. U.S. Energy Information Administration, *The National Energy Modeling System: An Overview 2009*, DOE/EIA-0581(2009) (Washington, DC, March 2009), web site http://www.eia.doe.gov/oiaf/aeo/overview/index.html.
2. U.S. Energy Information Administration, *Annual Energy Review 2008*, DOE/EIA-0384(2008) (Washington, DC, June 2009), web site www.eia.doe.gov/emeu/aer/contents.html.
3. U.S. Energy Information Administration, *Emissions of Greenhouse Gases in the United States 2007*, DOE/EIA-0573(2008) (Washington, DC, December 2009), web site www.eia.doe.gov/oiaf/1605/ggrpt/index.html.
4. U.S. 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.
5. Jet Information Services, Inc., *World Jet Inventory Year-End 2006* (Utica, NY, March 2007); and personal communication from Stuart Miller (Jet Information Services).
6. U.S. Energy Information Administration, *Assumptions to the Annual Energy Outlook 2010*, DOE/EIA-0554(2010) (Washington, DC, March 2010), web site www.eia.doe.gov/oiaf/aeo/assumption.
7. Corn ethanol production may exceed 15 billion gallons if it is economical to do so without the RFS credit.
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. 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. (Note: Taxes discussed in this footnote are in nominal dollars.)
9. U.S. Energy Information Administration, *Assumptions to the Annual Energy Outlook 2010*, DOE/EIA-0554(2010) (Washington, DC, March 2010), web site www.eia.doe.gov/oiaf/aeo/assumption.
10. California Environmental Protection Agency, Air Resources Board, "Phase 3 California Reformulated Gasoline Regulations," web site www.arb.ca.gov/regact/2007/carfg07/carfg07.htm.
11. U.S. Energy Information Administration, *Assumptions to the Annual Energy Outlook 2010*, DOE/EIA-0554(2010) (Washington, DC, March 2010), web site www.eia.doe.gov/oiaf/aeo/assumption.
12. 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).
13. 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).
14. These assumptions are based in part on Energy Information Administration, *Industrial Technology and Data Analysis Supporting the NEMS Industrial Model* (FOCIS Associates, October 2005).
15. U.S. 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).
16. U.S. Energy Information Administration, *Assumptions to the Annual Energy Outlook 2010*, DOE/EIA-0554(2010) (Washington, DC, March 2010), web site www.eia.doe.gov/oiaf/aeo/assumption.
17. U.S. Energy Information Administration, *Assumptions to the Annual Energy Outlook 2010*, DOE/EIA-0554(2010) (Washington, DC, March 2010), web site www.eia.doe.gov/oiaf/aeo/assumption.

Regional Maps

Figure F1. United States Census Divisions



Source: U.S. Energy Information Administration, Office of Integrated Analysis and Forecasting.

Figure F1. United States Census Divisions (cont.)

Division 1
New England

Connecticut
Maine
Massachusetts
New Hampshire
Rhode Island
Vermont

Division 2
Middle Atlantic

New Jersey
New York
Pennsylvania

Division 3
East North Central

Illinois
Indiana
Michigan
Ohio
Wisconsin

Division 4
West North Central

Iowa
Kansas
Minnesota
Missouri
Nebraska
North Dakota
South Dakota

Division 5
South Atlantic

Delaware
District of Columbia
Florida
Georgia
Maryland
North Carolina
South Carolina
Virginia
West Virginia

Division 6
East South Central

Alabama
Kentucky
Mississippi
Tennessee

Division 7
West South Central

Arkansas
Louisiana
Oklahoma
Texas

Division 8
Mountain

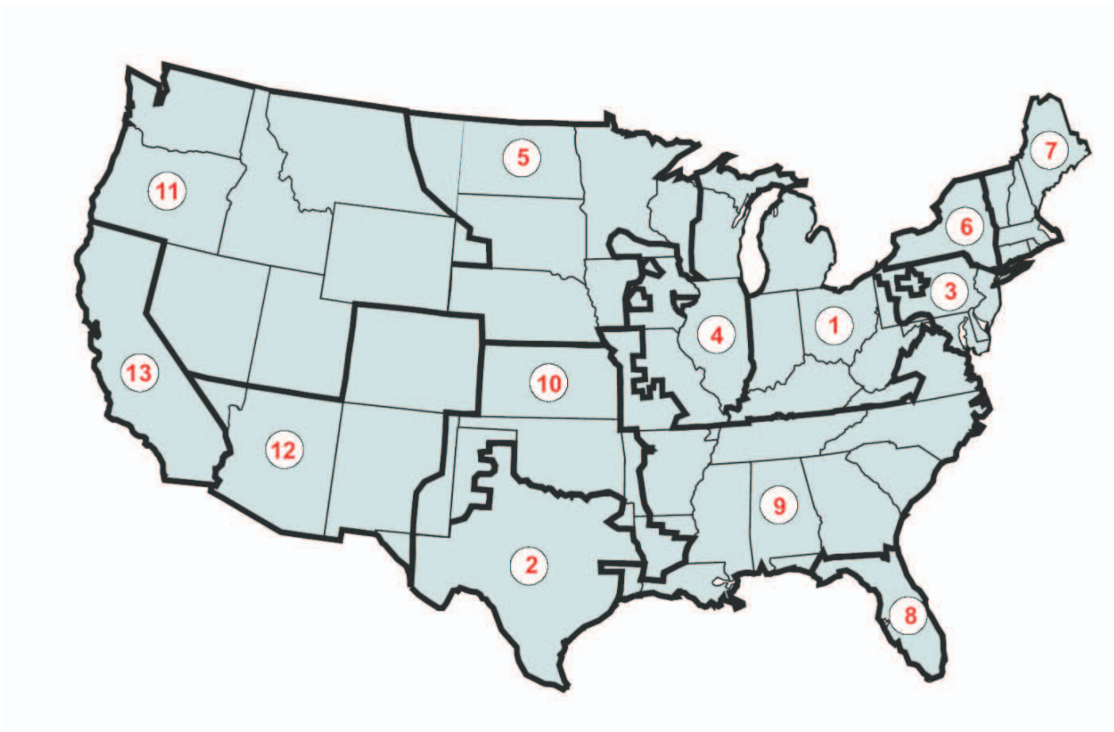
Arizona
Colorado
Idaho
Montana
Nevada
New Mexico
Utah
Wyoming

Division 9
Pacific

Alaska
California
Hawaii
Oregon
Washington

Source: U.S. Energy Information Administration, Office of Integrated Analysis and Forecasting.

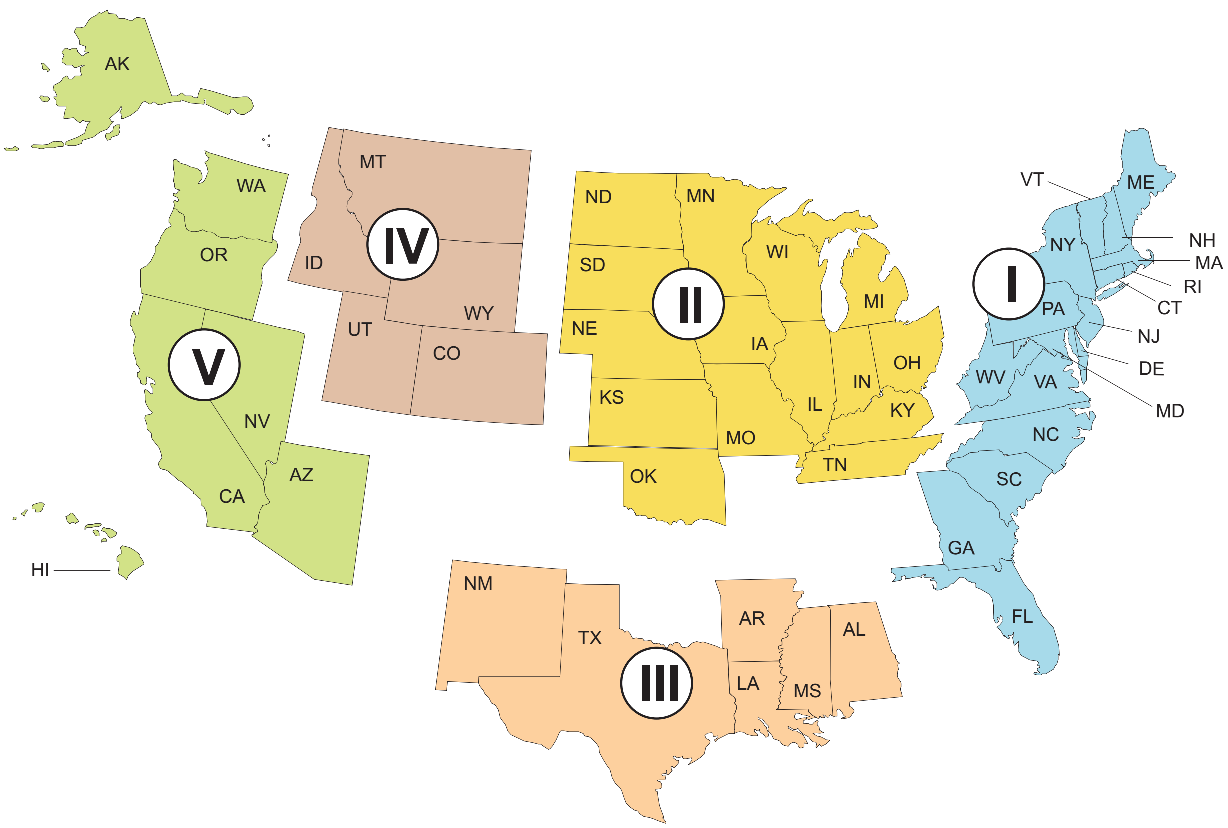
Figure F2. Electricity Market Module Regions



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)
5Mid-Continent Area Power Pool (MAPP)
6 New York (NY)
7. New England (NE)
8 Florida Reliability Coordinating Council (FL)
9 Southeastern Electric Reliability Council (SERC)
10 Southwest Power Pool (SPP)
11 Northwest Power Pool (NPP)
12 Rocky Mountain Power Area, Arizona, New New Mexico, and Southern Nevada (RA)
13 California (CA)

Source: U.S. Energy Information Administration, Office of Integrated Analysis and Forecasting.

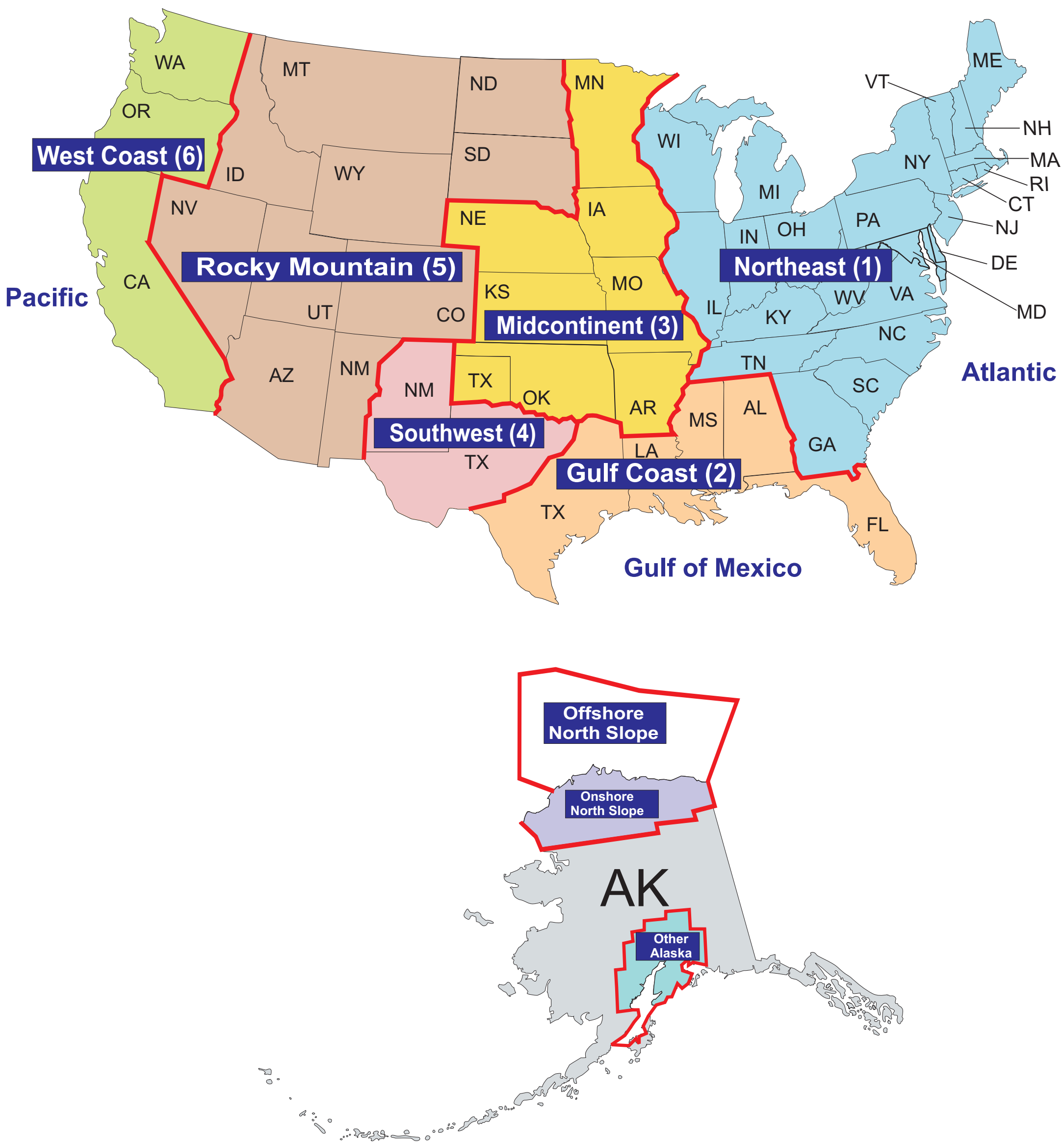
Figure F3. Petroleum Administration for Defense Districts



PAD District I -	East Coast
PAD District II -	Midwest
PAD District III -	Gulf Coast
PAD District IV -	Rocky Mountain
PAD District V -	West Coast

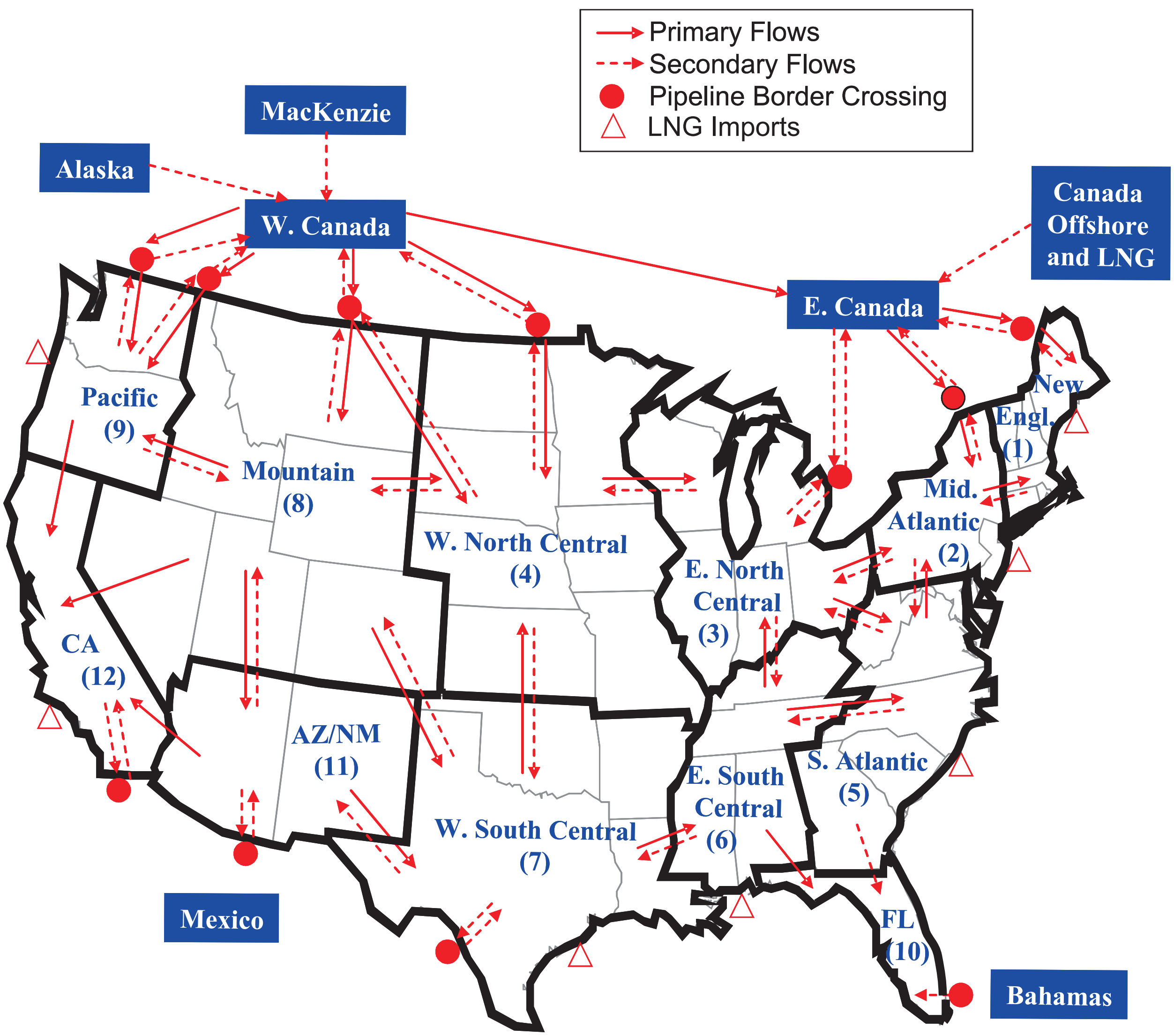
Source: U.S. Energy Information Administration, Office of Integrated Analysis and Forecasting.

Figure F4. Oil and Gas Supply Model Regions



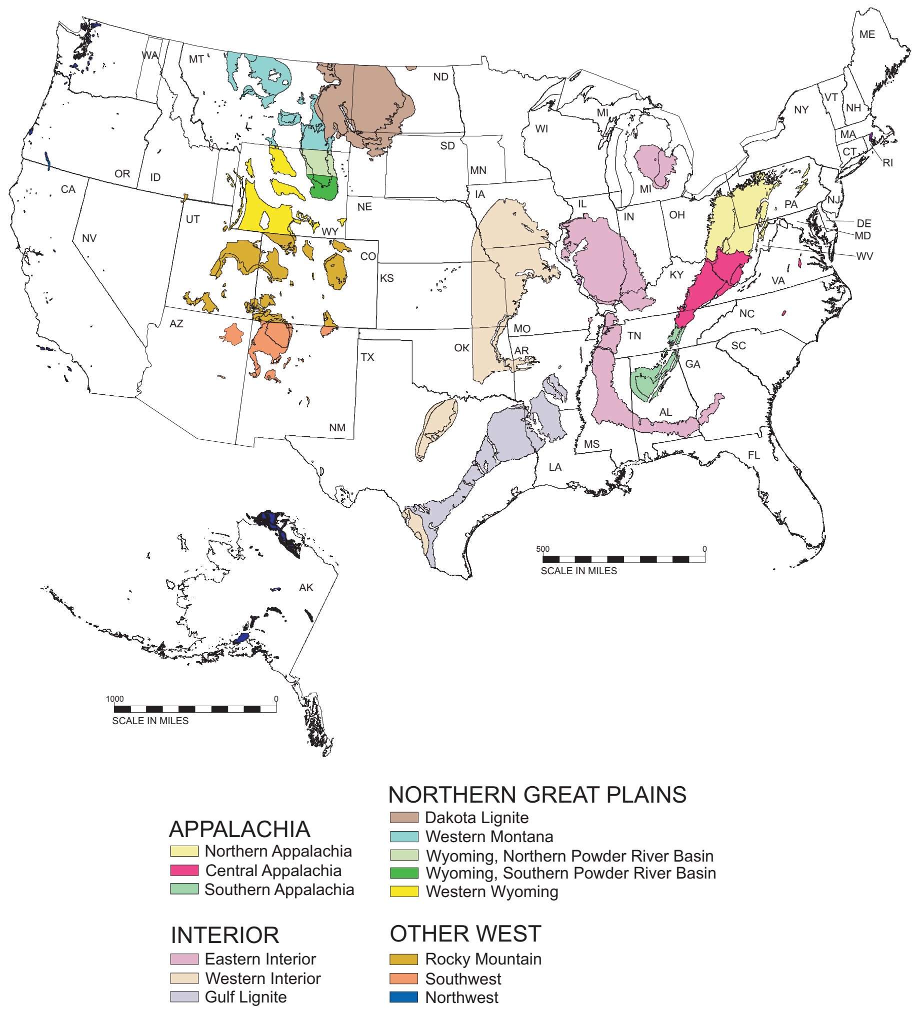
Source: U.S. Energy Information Administration, Office of Integrated Analysis and Forecasting.

Figure F5. Natural Gas Transmission and Distribution Model Regions



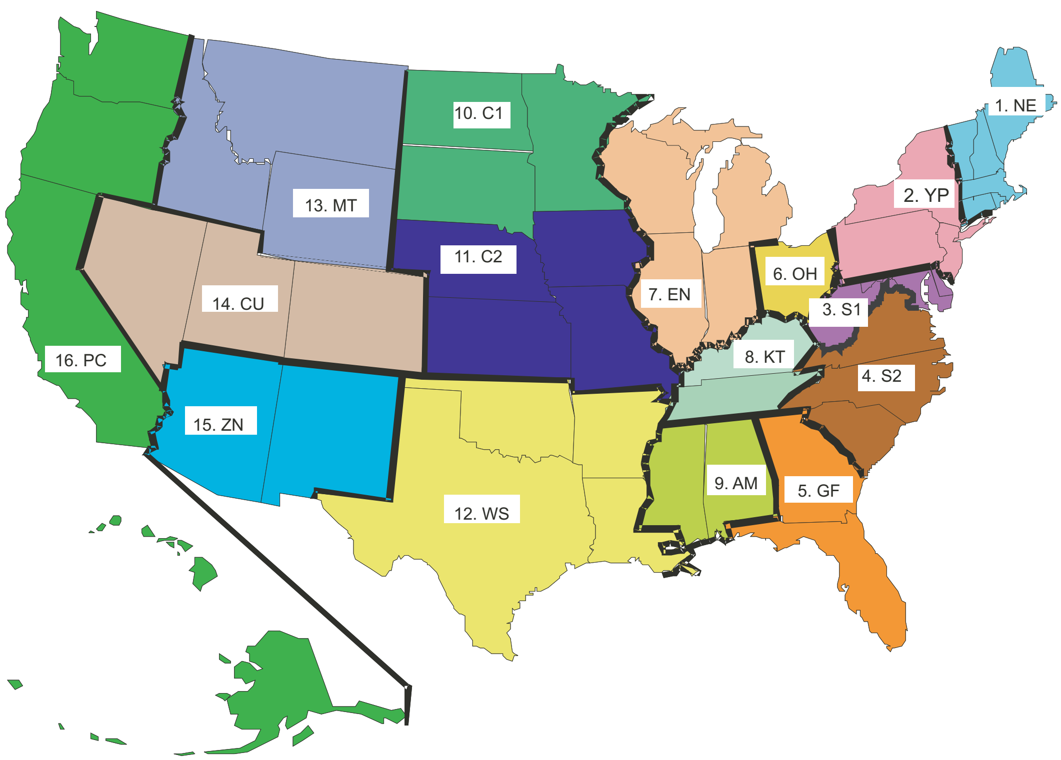
Source: U.S. Energy Information Administration, Office of Integrated Analysis and Forecasting.

Figure F6. Coal Supply Regions



Source: U.S. Energy Information Administration, Office of Integrated Analysis and Forecasting.

Figure F7. Coal Demand Regions



Region Code	Region Content
1. NE	CT,MA,ME,NH,RI,VT
2. YP	NY,PA,NJ
3. S1	WV,MD,DC,DE
4. S2	VA,NC,SC
5. GF	GA,FL
6. OH	OH
7. EN	IN,IL,MI,WI
8. KT	KY,TN

Region Code	Region Content
9. AM	AL,MS
10. C1	MN,ND,SD
11. C2	IA,NE,MO,KS
12. WS	TX,LA,OK,AR
13. MT	MT,WY,ID
14. CU	CO,UT,NV
15. ZN	AZ,NM
16. PC	AK,HI,WA,OR,CA

Source: U.S. 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	20.213
Consumption	million Btu per short ton	19.989
Coke Plants	million Btu per short ton	26.280
Industrial	million Btu per short ton	22.361
Residential and Commercial	million Btu per short ton	21.359
Electric Power Sector	million Btu per short ton	19.726
Imports	million Btu per short ton	25.116
Exports	million Btu per short ton	25.393
Coal Coke	million Btu per short ton	24.800
Crude Oil		
Production	million Btu per barrel	5.800
Imports[1]	million Btu per barrel	5.990
Liquids		
Consumption[1]	million Btu per barrel	5.301
Motor Gasoline[1]	million Btu per barrel	5.128
Jet Fuel	million Btu per barrel	5.670
Distillate Fuel Oil[1]	million Btu per barrel	5.775
Diesel Fuel[1]	million Btu per barrel	5.766
Residual Fuel Oil	million Btu per barrel	6.287
Liquefied Petroleum Gases[1]	million Btu per barrel	3.600
Kerosene	million Btu per barrel	5.670
Petrochemical Feedstocks[1]	million Btu per barrel	5.565
Unfinished Oils	million Btu per barrel	6.118
Imports[1]	million Btu per barrel	5.542
Exports[1]	million Btu per barrel	5.840
Ethanol	million Btu per barrel	3.539
Biodiesel	million Btu per barrel	5.376
Natural Gas Plant Liquids		
Production[1]	million Btu per barrel	3.948
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	1,029
Electric Power Sector	Btu per cubic foot	1,027
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 2008.
Btu = British thermal unit.
Sources: Energy Information Administration (EIA), *Annual Energy Review 2008*, DOE/EIA-0384(2008) (Washington, DC, June 2009), and EIA, AEO2010 National Energy Modeling System run AEO2010R.D111809A.