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# Annual Energy Outlook 2013

## with Projections to 2040

Independent Statistics & Analysis
U.S. Energy Information Administration

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The *AEO2013* is available on the EIA website at www.eia.gov/forecasts/aeo. Assumptions underlying the projections, tables of regional results, and other detailed results will also be available, at www.eia.gov/forecasts/aeo/assumptions. Model documentation reports for the National Energy Modeling System are available at website www.eia.gov/analysis/model-documentation.cfm and will be updated for the *AEO2013* during 2013.

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# Annual Energy Outlook 2013

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**U.S. Energy Information Administration**
Office of Integrated and International Energy Analysis
U.S. Department of Energy
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# Preface

The *Annual Energy Outlook 2013 (AEO2013)*, prepared by the U.S. Energy Information Administration (EIA), presents long-term projections of energy supply, demand, and prices through 2040, based on results from EIA's National Energy Modeling System. EIA published an "early release" version of the *AEO2013* Reference case in December 2012.

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 and regulations, such as: Updated handling of the U.S. Environmental Protection Agency's (EPA) National Emissions Standards for Hazardous Air Pollutants for industrial boilers and process heaters [*1*]; New light-duty vehicle (LDV) greenhouse gas (GHG) and corporate average fuel economy (CAFE) standards for model years 2017 to 2025 [*2*]; Reinstatement of the Clean Air Interstate Rule (CAIR) [*3*] after the court's announcement of intent to vacate the Cross-State Air Pollution Rule (CSAPR) [*4*]; and Modeling of California's Assembly Bill 32, the Global Warming Solutions Act (AB 32) [*5*], which allows for representation of a cap-and-trade program developed as part of California's GHG reduction goals for 2020.

The "Issues in focus" section contains discussions of selected energy topics, including a discussion of the results in two cases that adopt different assumptions about the future course of existing policies, with one case assuming the elimination of sunset provisions in existing policies and the other case assuming the elimination of the sunset provisions and the extension of a selected group of existing public policies—CAFE standards, appliance standards, and production tax credits. Other discussions include: oil price and production trends in *AEO2013*; U.S. reliance on imported liquids under a range of cases; competition between coal and natural gas in electric power generation; high and low nuclear scenarios through 2040; and the impact of growth in natural gas liquids production.

The "Market trends" section summarizes the projections for energy markets. The analysis in *AEO2013* 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. Complete tables for all the alternative cases are available on EIA's website in a table browser at http://www.eia.gov/oiaf/aeo/tablebrowser.

*AEO2013* projections are based generally on federal, state, and local laws and regulations in effect as of the end of September 2012. 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. In certain situations, however, where it is clear that a law or regulation will take effect shortly after the *Annual Energy Outlook (AEO)* is completed, it may be considered in the projection.

*AEO2013* 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 the U.S. Energy Information Administration (EIA) are not statements of what will happen but of what might happen, given the assumptions and methodologies used for any particular scenario. The *Annual Energy Outlook 2013 (AEO2013)* 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 *AEO2013* 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 *AEO2013* 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.

# Updated *Annual Energy Outlook 2013* Reference case (April 2013)

The *AEO2013* Reference case included as part of this complete report, released in April 2013, was updated from the *AEO2012* Reference case released in June 2012. The Reference case was updated to reflect new legislation or regulation enacted since that time or to incorporate modeling changes. Major changes made in the Reference case include:

- Extension of the projection period through 2040, an additional five years beyond *AEO2012*.
- Adoption of a new Liquid Fuels Market Module (LFMM) in place of the Petroleum Market Module used in earlier *AEO*s provides for more granular and integrated modeling of petroleum refineries and all other types of current and potential future liquid fuels production technologies. This allows more direct analysis and modeling of the regional supply and demand effects involving crude oil and other feedstocks, current and future processes, and marketing to consumers.
- A shift to the use of Brent spot price as the reference oil price. *AEO2013* also presents the average West Texas Intermediate spot price of light, low-sulfur crude oil delivered in Cushing, Oklahoma, and includes 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.
- A shift from using regional natural gas wellhead prices to using representative regional natural gas spot prices as the basis of the natural gas supply price. Due to this change, the methodology for estimating the Henry Hub price was revised.
- Updated handling of data on flex-fuel vehicles (FFVs) to better reflect consumer preferences and industry response. FFVs are necessary to meet the renewable fuels standard, but the phasing out of CAFE credits for their sale and limited demand from consumers reduce their market penetration.
- A revised outlook for industrial production to reflect the impacts of increased shale gas production and lower natural gas prices, which result in faster growth for industrial production and energy consumption. The industries affected include, in particular, bulk chemicals and primary metals.
- Incorporation of a new aluminum process flow model in the industrial sector, which allows for diffusion of technologies through choices made among known commercial and emerging technologies based on relative capital costs and fuel expenditures and provides for a more realistic representation of the evolution of energy consumption than in previous *AEO*s.
- An enhanced industrial chemical model, in several respects: the baseline liquefied petroleum gas (LPG) feedstock data have been aligned with 2006 survey data; use of an updated propane-pricing mechanism that reflects natural gas price influences in order to allow for price competition between LPG feedstock and petroleum-based (naphtha) feedstock; and specific accounting in the Industrial Demand Model for propylene supplied by the LFMM.
- Updated handling of the EPA's National Emissions Standards for Hazardous Air Pollutants for industrial boilers and process heaters to address the maximum degree of emissions reduction using maximum achievable control technology. An industrial capital expenditure and fuel price adjustment for coal and residual fuel has been applied to reflect risk perception about the use of those fuels relative to natural gas.
- Augmentation of the construction and mining models in the Industrial Demand Model to better reflect *AEO2013* assumptions regarding energy efficiencies in off-road vehicles and buildings, as well as the productivity of coal, oil, and natural gas extraction.
- Adoption of final model year 2017 to 2025 GHG emissions and CAFE standards for LDVs, which increases the projected fuel economy of new LDVs to 47.3 mpg in 2025.
- Updated handling of the representation of purchase decisions for alternative fuels for heavy-duty vehicles. Market factors used to calculate the relative cost of alternative-fuel vehicles, specifically natural gas, now represent first buyer-user behavior and slightly longer breakeven payback periods, significantly increasing the demand for natural gas fuel in heavy trucks.
- Updated modeling of LNG export potential, which includes a rudimentary assessment of pricing of natural gas in international markets.
- Updated power generation unit costs that capture recent cost declines for some renewable technologies, which tend to lead to greater use of renewable generation, particularly solar technologies.
- Reinstatement of CAIR after the court's announcement of intent to vacate CSAPR.
- Modeling of California's AB 32, that allows for representation of a cap-and-trade program developed as part of California's GHG reduction goals for 2020. The coordinated regulations include an enforceable GHG cap that will decline over time. *AEO2013* reflects all covered sectors, including emissions offsets and allowance allocations.
- Incorporation of the California Low Carbon Fuel Standard, which requires fuel producers and importers who sell motor gasoline or diesel fuel in California to reduce the carbon intensity of those fuels by 10 percent between 2012 and 2020 through the increased sale of alternative low-carbon fuels.

Future analyses using the *AEO2013* Reference case will start from the version of the Reference case released with this complete report.

# Endnotes for Preface

**Links current as of March 2013**

1. U.S. Government Printing Office, "Clean Air Act," 42 U.S.C. 7412 (Washington, DC: 2011), http://www.gpo.gov/fdsys/pkg/USCODE-2011-title42/pdf/USCODE-2011-title42-chap85-subchapI-partA.pdf.
2. U.S. Environmental Protection Agency and Department of Transportation, National Highway Traffic Safety Administration, "2017 and Later Model Year Light-Duty Vehicle Greenhouse Gas Emissions and Corporate Average Fuel Economy Standards; Final Rule," *Federal Register*, Vol. 77, No. 199 (Washington, DC: October 15, 2012), https://www.federalregister.gov/articles/2012/10/15/2012-21972/2017-and-later-model-year-light-duty-vehicle-greenhouse-gas-emissions-and-corporate-average-fuel.
3. U.S. Environmental Protection Agency, "Clean Air Interstate Rule (CAIR)" (Washington, DC: December 19, 2012), http://www.epa.gov/cair/index.html#older.
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5. California Legislative Information, "Assembly Bill No. 32: California Global Warming Solutions Act of 2006" (Sacramento, CA: September 27, 2006), http://www.leginfo.ca.gov/pub/05-06/bill/asm/ab_0001-0050/ab_32_bill_20060927_chaptered.pdf.

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# Executive summary

The projections in the U.S. Energy Information Administration's *Annual Energy Outlook 2013 (AEO2013)* focus on the factors that shape the U.S. energy system over the long term. Under the assumption that current laws and regulations remain unchanged throughout the projections, the *AEO2013* Reference case provides a basis for examination and discussion of energy production, consumption, technology, and market trends and the direction they may take in the future. *AEO2013* also includes alternative cases (see Appendix E, Table E1), which explore important areas of uncertainty for markets, technologies, and policies in the U.S. energy economy. Many of the implications of the alternative cases are discussed in the Issues in focus section of *AEO2013*.

Key results highlighted in the *AEO2013* Reference and alternative cases include:

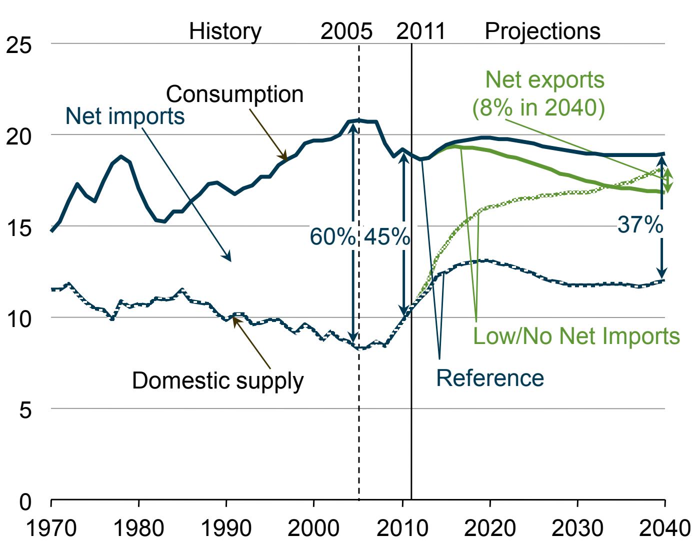
- Continued strong growth in domestic crude oil production over the next decade—largely as a result of rising production from tight formations—and increased domestic production of natural gas;
- The potential for even stronger growth in domestic crude oil production under alternative conditions;
- Evolving natural gas markets that spur increased use of natural gas for electric power generation and transportation and an expanding natural gas export market;
- A decline in motor gasoline consumption over the projection period, reflecting the effects of more stringent corporate average fuel economy (CAFE) standards, as well as growth in diesel fuel consumption and increased use of natural gas to power heavy-duty vehicles; and
- Low electricity demand growth, and continued increases in electricity generation capacity fueled by natural gas and renewable energy, which when combined with environmental regulations put pressure on coal use in the electric power sector. In some cases, coal's share of total electricity generation falls below the natural gas share through the end of the projection period.

## Oil production, particularly from tight oil plays, rises over the next decade, leading to a reduction in net import dependence

Crude oil production has increased since 2008, reversing a decline that began in 1986. From 5.0 million barrels per day in 2008, U.S. crude oil production increased to 6.5 million barrels per day in 2012. Improvements in advanced crude oil production technologies continues to lift domestic supply, with domestic production of crude oil increasing in the Reference case before declining gradually beginning in 2020 for the remainder of the projection period. The projected growth results largely from a significant increase in onshore crude oil production, particularly from shale and other tight formations, which has been spurred by technological advances and relatively high oil prices. Tight oil development is still at an early stage, and the outlook is highly uncertain. In some of the *AEO2013* alternative cases, tight oil production and total U.S. crude oil production are significantly above their levels in the Reference case.

The net import share of U.S. petroleum and other liquids consumption (including crude oil, petroleum liquids, and liquids derived from nonpetroleum sources) grew steadily from the mid-1980s to 2005 but has fallen in every year since then (Figure 1). In the Reference case, U.S. net imports of petroleum and other liquids decline through 2019, while still providing approximately one-third of total U.S. supply. The net import share of U.S. petroleum and other liquids consumption continues to decline in the Reference case, falling to 34 percent in 2019 before increasing to 37 percent in 2040.

### Figure 1. Net import share of U.S. liquids supply in two cases, 1970-2040 (million barrels per day)




The U.S. could become a net exporter of liquid fuels under certain conditions. An article in the Issues in focus section considers four cases that examine the impacts of various assumptions about U.S. dependence on imported liquids. Two cases (Low Oil and Gas Resource and High Oil and Gas Resource) vary only the supply assumptions, and two cases (Low/No Net Imports and High Net Imports) vary both the supply and demand assumptions. The different assumptions in the four cases generate wide variation from the liquid fuels import dependence values in the *AEO2013* Reference case. In the Low/No Net Imports case, the United States ends its reliance on net imports of liquid fuels in the mid-2030s, with net exports rising to 8 percent of total U.S. liquid fuel production in 2040. In contrast, in the High Net Imports case, net petroleum import dependence is above 44 percent in 2040, which is higher than the Reference case level of 37 percent but still well below the 2005 level of 60 percent.

While other combinations of assumptions or unforeseen technology breakthroughs might produce a comparable outcome, the assumptions in the Low/No Imports case illustrate the magnitude and type of changes that would be required for the United States to end its reliance on net imports of liquid fuels, which began after World War II and has continued to the present day. Some of the assumptions in the Low/No Net Imports case, such as increased fuel economy for light-duty vehicles (LDVs) after 2025 and wider access to offshore resources, could be influenced by possible future energy policies. However, other assumptions in this case, such as the greater availability of onshore technically recoverable oil and natural gas resources, depend on geological outcomes that cannot be influenced by policy measures. In addition, economic trends, consumer preferences and behaviors, and technological factors also may be unaffected, or only modestly affected, by policy measures.

In the High Oil and Gas Resource case, changes due to the supply assumptions alone cause net import dependence to decline to 7 percent in 2040, with U.S. crude oil production rising to 10.2 million barrels per day in 2040, or 4.1 million barrels per day above the Reference case level. Tight oil production accounts for more than 77 percent (or 3.2 million barrels per day) of the difference in production between the two cases. Production of natural gas plant liquids in the United States also exceeds the Reference case level.

One of the most uncertain aspects of this analysis is the potential effect of different scenarios on the global market for liquid fuels, which is highly integrated. Strategic choices made by leading oil-exporting countries could result in U.S. price and quantity changes that differ significantly from those presented here. Moreover, regardless of how much the United States reduces its reliance on imported liquids, consumer prices will not be insulated from global oil prices if current policies and regulations remain in effect and world markets for delivery continue to be competitive.

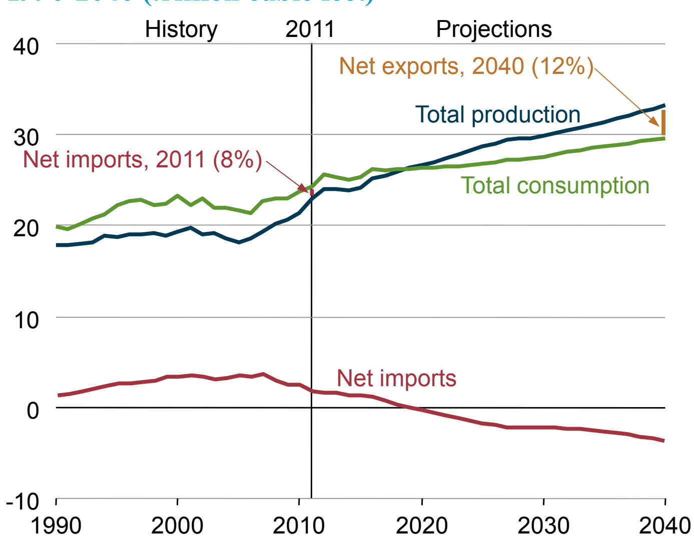
## The United States becomes a net exporter of natural gas

U.S. dry natural gas production increases 1.3 percent per year throughout the Reference case projection, outpacing domestic consumption by 2019 and spurring net exports of natural gas (Figure 2). Higher volumes of shale gas production are central to higher total production volumes and a transition to net exports. As domestic supply has increased in recent years, natural gas prices have declined, making the United States a less attractive market for imported natural gas and more attractive for export.

U.S. net exports of natural gas grow to 3.6 trillion cubic feet in 2040 in the Reference case. Most of the projected growth in U.S. exports consists of pipeline exports to Mexico, which increase steadily as growing volumes of imported natural gas from the United States fill the widening gap between Mexico's production and consumption. Declining natural gas imports from Canada also contribute to the growth in U.S. net exports. Net U.S. imports of natural gas from Canada decline sharply from 2016 to 2022, then stabilize somewhat before dropping off again in the final years of the projection, as continued growth in domestic production mitigates the need for imports.

Continued low levels of liquefied natural gas (LNG) imports in the projection period, combined with increased U.S. exports of domestically sourced LNG, position the United States as a net exporter of LNG by 2016. U.S. exports of domestically sourced LNG (excluding exports from the existing Kenai facility in Alaska) begin in 2016 and rise to a level of 1.6 trillion cubic feet per year in 2027. One-half of the U.S. exports of LNG originate from the Lower 48 states and the other half from Alaska. The prospects for exports are highly uncertain, however, depending on many factors that are difficult to gauge, such as the development of new production capacity in foreign countries, particularly from deepwater reservoirs, shale gas deposits, and the Arctic. In addition, future U.S. exports of LNG depend on a number of other factors, including the speed and extent of price convergence in global natural gas markets and the extent to which natural gas competes with liquids in domestic and international markets.

### Figure 2. Total U.S. natural gas production, consumption, and net imports in the Reference case, 1990-2040 (trillion cubic feet)




In the High Oil and Gas Resource case, with more optimistic resource assumptions, U.S. LNG exports grow to more than 4 trillion cubic feet in 2040. Most of the additional exports originate from the Lower 48 states.

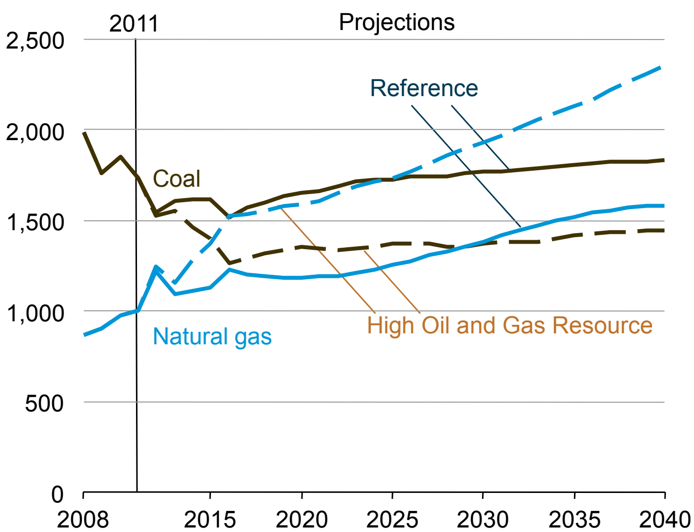
## Coal's share of electric power generation falls over the projection period

Although coal is expected to continue its important role in U.S. electricity generation, there are many uncertainties that could affect future outcomes. Chief among them are the relationship between coal and natural gas prices and the potential for policies aimed at reducing greenhouse gas (GHG) emissions. In 2012, natural gas prices were low enough for a few months for power companies to run natural gas-fired generation plants more economically than coal plants in many areas. During those months, coal and natural gas were nearly tied in providing the largest share of total electricity generation, something that had never happened before. In the Reference case, existing coal plants recapture some of the market they recently lost to natural gas plants because natural gas prices rise more rapidly than coal prices. However, the rise in coal-fired generation is not sufficient for coal to maintain its generation share, which falls to 35 percent by 2040 as the share of generation from natural gas rises to 30 percent.

In the alternative High Oil and Natural Gas Resource case, with much lower natural gas prices, natural gas supplants coal as the top source of electricity generation (Figure 3). In this case, coal accounts for only 27 percent of total generation in 2040, while natural gas accounts for 43 percent. However, while natural gas generation in the power sector surpasses coal generation in 2016 in this case, more coal energy than natural gas energy is used for power generation until 2035 because of the higher average thermal efficiency of the natural gas-fired generating units. Coal use for electric power generation falls to 14.7 quadrillion Btu in 2040 in the High Oil and Natural Gas Resource case (compared with 18.7 quadrillion Btu in the Reference case), while natural gas use rises to 15.1 quadrillion Btu in the same year (Figure 4). Natural gas use for electricity generation is 9.7 quadrillion Btu in 2040 in the Reference case.

Coal's generation share and the associated carbon dioxide ($CO_2$) emissions could be further reduced if policies aimed at reducing GHG emissions were enacted (Figure 5). For example, in the GHG15 case, which assumes a fee on $CO_2$ emissions that starts at $15 per metric ton in 2014 and increases by 5 percent per year through 2040, coal's share of total generation falls to 13 percent in 2040. Energy-related $CO_2$ emissions also fall sharply in the GHG15 case, to levels that are 10 percent, 15 percent, and 24 percent lower than projected in the Reference case in 2020, 2030, and 2040, respectively. In 2040, energy-related $CO_2$ emissions in the GHG15 case are 28 percent lower than the 2005 total. In the GHG15 case, coal use in the electric power sector falls to only 6.1 quadrillion Btu in 2040, a decline of about two-thirds from the 2011 level. While natural gas use in the electric power sector initially displaces coal use in this case, reaching more than 10 quadrillion Btu in 2016, it falls to 8.8 quadrillion Btu in 2040 as growth in renewable and nuclear generation offsets natural gas use later in the projection period.

**Figure 3. Electricity generation from coal and natural gas in two cases, 2008-2040 (billion kilowatthours)**




## With more efficient light-duty vehicles, motor gasoline consumption declines while diesel fuel use grows, even as more natural gas is used in heavy-duty vehicles

The *AEO2013* Reference case incorporates the GHG and CAFE standards for LDVs [6] through the 2025 model year. The increase in vehicle efficiency reduces LDV energy use from 16.1 quadrillion Btu in 2011 to 14.0 quadrillion Btu in 2025, predominantly motor gasoline (Figure 6). LDV energy use continues to decline through 2036, then levels off until 2039 as growth in population and vehicle miles traveled offsets more modest improvement in fuel efficiency.

**Figure 4. Coal and natural gas use in the electric power sector in three cases, 2011, 2025, and 2040 (quadrillion Btu)**

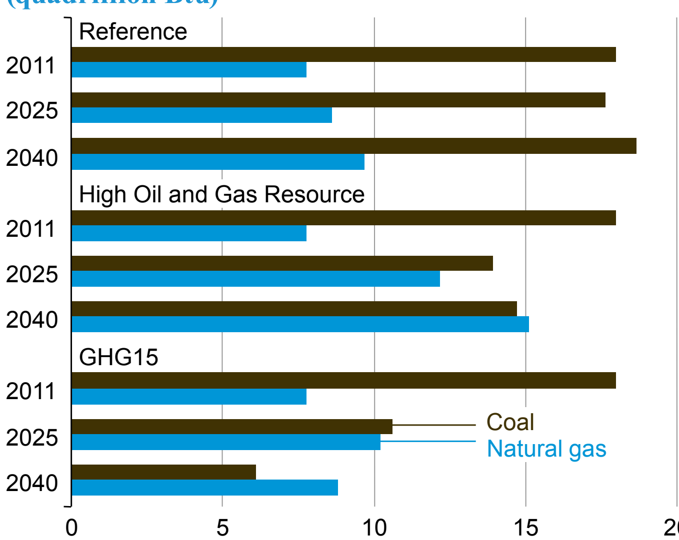
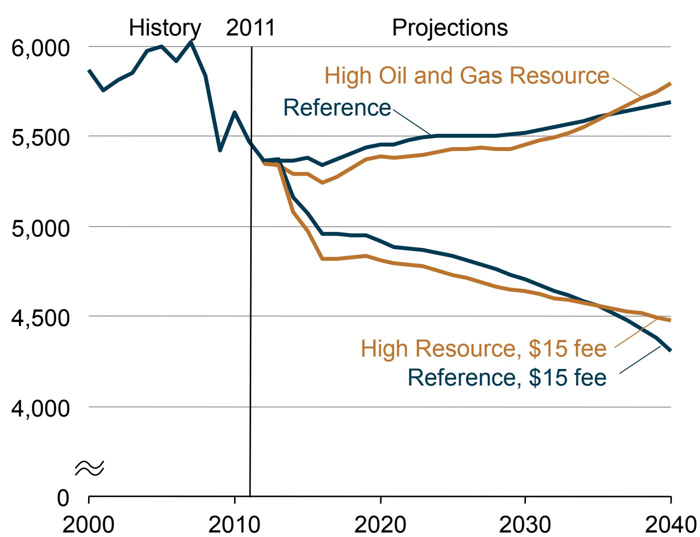



**Figure 5. Energy-related carbon dioxide emissions in four cases, 2000-2040 (million metric tons)**



Furthermore, the improved economics of natural gas as a fuel for heavy-duty vehicles result in increased use that offsets a portion of diesel fuel consumption. The use of petroleum-based diesel fuel is also reduced by growing consumption of diesel produced with gas-to-liquids (GTL) technology. Natural gas use in vehicles (including natural gas used in the production of GTL) totals 1.4 trillion cubic feet in 2040 in the Reference case, displacing 0.7 million barrels per day of other motor fuels [7]. Diesel fuel use nonetheless increases at a relatively strong rate, with freight travel demand supported by increasing industrial production.

### Natural gas consumption grows in industrial and electric power sectors as domestic production also serves an expanding export market

Relatively low natural gas prices, maintained by growing shale gas production, spur increased use in the industrial and electric power sectors, particularly over the next decade. In the Reference case, natural gas use in the industrial sector increases by 16 percent, from 6.8 trillion cubic feet per year in 2011 to 7.8 trillion cubic feet per year in 2025. After 2025, the growth of natural gas consumption in the industrial sector slows, while total U.S. consumption continues to grow (Figure 7). This additional growth is mostly for use in the electric power sector. Although natural gas continues to capture a growing share of total electricity generation, natural gas consumption by power plants does not increase as sharply as generation because new plants are very efficient (needing less fuel per unit of power output). The natural gas share of generation rose from 16 percent of generation in 2000 to 24 percent in 2011 and increases to 27 percent in 2025 and 30 percent in 2040. Natural gas use in the residential and commercial sectors remains nearly constant, as increasing end-use demand is balanced by increasing end-use efficiency.

Natural gas consumption also grows in other markets in the Reference case, including heavy-duty freight transportation (trucking) and as a feedstock for GTL production of diesel and other fuels. Those uses account for 6 percent of total U.S. natural gas consumption in 2040, as compared with almost nothing in 2011.

Natural gas use in the electric power sector grows even more sharply in the High Oil and Natural Gas Resource case, as the natural gas share of electricity generation grows to 39 percent, reaching 14.8 trillion cubic feet in 2040, more than 55 percent greater than in the Reference case. Industrial sector natural gas consumption growth is also stronger in this case, with growth continuing after 2025 and reaching 13.0 trillion cubic feet in 2040 (compared to 10.5 trillion cubic feet in 2040 in the Reference case). Much of the industrial growth in the High Oil and Natural Gas Resource case is associated with natural gas use for GTL production and increased lease and plant use in natural gas production.

### Renewable fuel use grows at a faster rate than fossil fuel use

The share of U.S. electricity generation from renewable energy grows from 13 percent in 2011 to 16 percent in 2040 in the Reference case. Electricity generation from solar and, to a lesser extent, wind energy sources grows as their costs decline, making them more economical in the later years of the projection. However, the rate of growth in renewable electricity generation is sensitive to several factors, including natural gas prices and the possible implementation of policies to reduce GHG emissions. If future natural gas prices are lower than projected in the Reference case, as illustrated in the High Oil and Gas Resource case, the share of renewable generation would grow more slowly, to only 14 percent in 2040. Alternatively, if broad-based policies to reduce GHG emissions were enacted, renewable generation would be expected to grow more rapidly. In three cases that assume GHG emissions fees that range from $10 to $25 per metric ton in 2014 and rise by 5 percent per year through 2040 (GHG10, GHG15, and GHG25), the

**Figure 6. Transportation energy consumption by fuel, 1990-2040 (quadrillion Btu)**

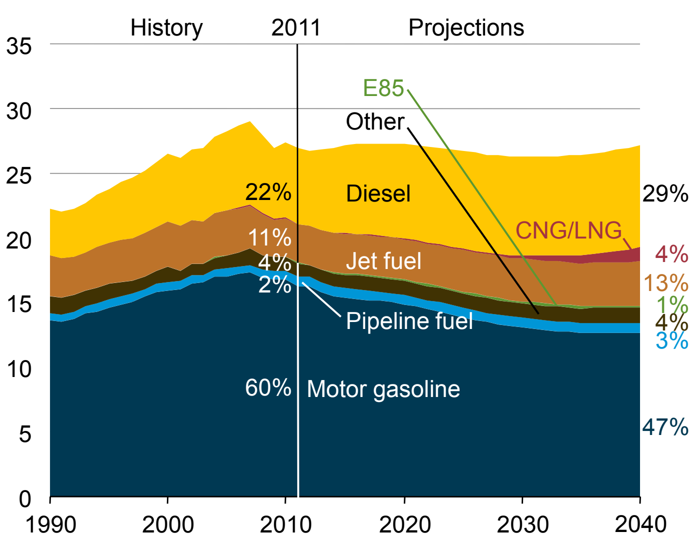



**Figure 7. U.S. dry natural gas consumption by sector, 2005-2040 (trillion cubic feet)**

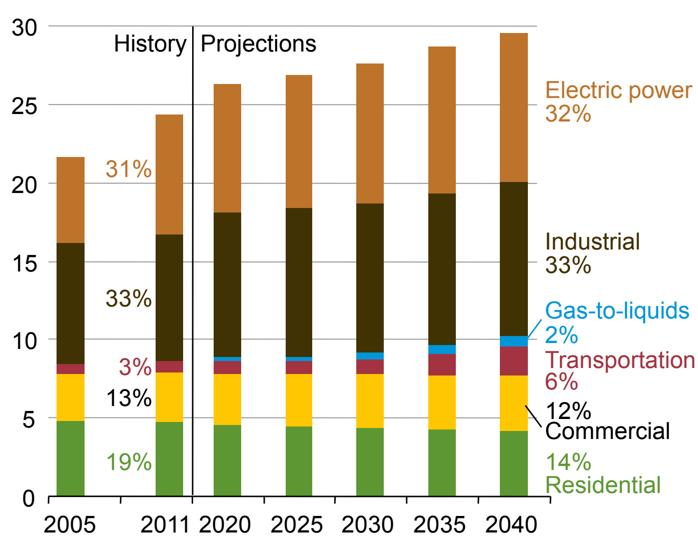
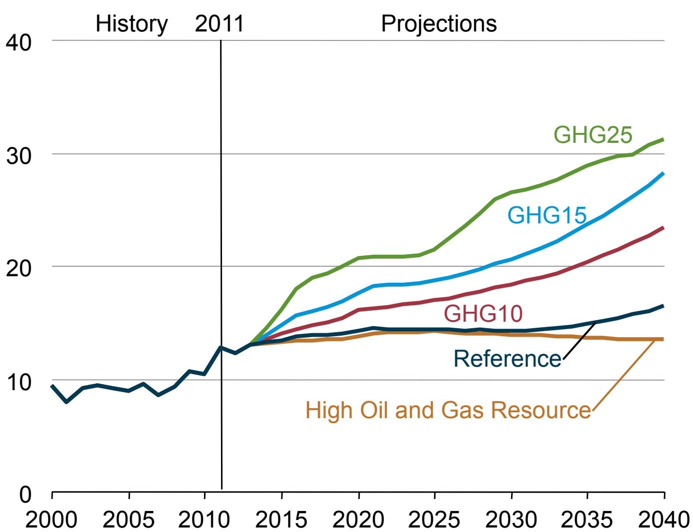


**Figure 8. Renewable energy share of U.S. electricity generation in five cases, 2000-2040 (percent)**




renewable share of total U.S. electricity generation in 2040 ranges from 23 percent to 31 percent (Figure 8).

The *AEO2013* Reference case reflects a less optimistic outlook for advanced biofuels to capture a rapidly growing share of the liquid fuels market than earlier *Annual Energy Outlooks*. As a result, biomass use in the Reference case totals 5.9 quadrillion Btu in 2035 and 7.1 quadrillion Btu in 2040, up from 4.0 quadrillion Btu in 2011.

# Endnotes for Executive summary

**Links current as of March 2013**

6. U.S. Environmental Protection Agency and National Highway Traffic Safety Administration, "2017 and Later Model Year Light-Duty Vehicle Greenhouse Gas Emissions and Corporate Average Fuel Economy Standards," *Federal Register*, Vol. 77, No. 199 (Washington, DC: October 15, 2012), https://www.federalregister.gov/articles/2012/10/15/2012-21972/2017-and-later-model-year-light-duty-vehicle-greenhouse-gas-emissions-and-corporate-average-fuel.
7. Liquid motor fuels include diesel and liquid fuels from gas-to-liquids (GTL) processes. Liquid fuel volumes from GTL for motor vehicle use are estimated based on the ratio of onroad diesel and gasoline to total diesel and gasoline.

# Legislation and regulations

## Introduction

The *Annual Energy Outlook 2013 (AEO2013)* generally represents current federal and state legislation and final implementation regulations as of the end of September 2012. The *AEO2013* Reference case assumes that current laws and regulations affecting the energy sector are largely unchanged throughout the projection period (including the implication that laws that include sunset dates are no longer in effect at the time of those sunset dates) [*8*]. The potential impacts of proposed legislation, regulations, or standards—or of sections of authorizing legislation that have been enacted but are not funded or where parameters will be set in a future regulatory process—are not reflected in the *AEO2013* Reference case, but some are considered in alternative cases. The *AEO2013* Reference case does not reflect the provisions of the American Taxpayer Relief Act of 2012 (P.L. 112-240) enacted on January 1, 2013 [*9*]. Key energy-related provisions of that legislation—including extension of the production tax credit for renewable generation, tax credits for energy-efficient appliances, and tax credits for selected biofuels—are reflected in an alternative case completed as part of *AEO2013*. This section summarizes federal and state legislation and regulations newly incorporated or updated in *AEO2013* since the completion of the *Annual Energy Outlook 2012 (AEO2012)*.

Examples of federal and state legislation and regulations incorporated in the *AEO2013* Reference case or whose handling has been modified include:

- Incorporation of new light-duty vehicle greenhouse gas emissions (GHG) and corporate average fuel economy (CAFE) standards for model years 2017 to 2025 [*10*]
- Continuation of the Clean Air Interstate Rule (CAIR) [*11*] after the court's announcement of intent to vacate the Cross-State Air Pollution Rule (CSAPR) [*12*]
- Updated handling of the U.S. Environmental Protection Agency's (EPA) National Emissions Standards for Hazardous Air Pollutants (NESHAP) for industrial boilers and process heaters [*13*]
- Modeling of California's Assembly Bill 32, the Global Warming Solutions Act (AB 32) [*14*], that allows for representation of a cap-and-trade program developed as part of California's GHG reduction goals for 2020
- Incorporation of the California Low Carbon Fuel Standard (LCFS) [*15*], which requires fuel producers and importers who sell motor gasoline or diesel fuel in California to reduce the carbon intensity of those fuels by an average of 10 percent between 2012 and 2020 through the mixing and increased sale of alternative low-carbon fuels.

There are many other pieces of legislation and regulation that appear to have some probability of being enacted in the not-too-distant future, and some laws include sunset provisions that may be extended. However, it is difficult to discern the exact forms that the final provisions of pending legislation or regulations will take, and sunset provisions may or may not be extended. Even in situations where existing legislation contains provisions to allow revision of implementing regulations, those provisions may not be exercised consistently. Many pending provisions are examined in alternative cases included in *AEO2013* or in other analyses completed by the U.S. Energy Information Administration (EIA). In addition, at the request of the Administration and Congress, EIA has regularly examined the potential implications of other possible energy options in Service Reports. Those reports can be found on the EIA website at http://www.eia.gov/oiaf/service_rpts.htm.

## 1. Greenhouse gas emissions and corporate average fuel economy standards for 2017 and later model year light-duty vehicles

On October 15, 2012, EPA and the National Highway Traffic Safety Administration (NHTSA) jointly issued a final rule for tailpipe emissions of carbon dioxide ($CO_2$) and CAFE standards for light-duty vehicles, model years 2017 and beyond [*16*]. EPA, operating under powers granted by the Clean Air Act (CAA), issued final $CO_2$ emissions standards for model years 2017 through 2025 for passenger cars and light-duty trucks, including medium-duty passenger vehicles. NHTSA, under powers granted by the Energy Policy and Conservation Act, as amended by the Energy Independence and Security Act, issued CAFE standards for passenger cars and light-duty trucks, including medium-duty passenger vehicles, for model years 2017 through 2025.

The new $CO_2$ emissions and CAFE standards will first affect model year 2017 vehicles, with compliance requirements increasing in stringency each year thereafter through model year 2025. EPA has established standards that are expected to require a fleet-wide average of 163 grams $CO_2$ per mile for light-duty vehicles in model year 2025, which is equivalent to a fleet-wide average of 54.5 miles per gallon (mpg) if reached only through fuel economy. However, the $CO_2$ emissions standards can be met in part through reductions in air-conditioning leakage and the use of alternative refrigerants, which reduce $CO_2$-equivalent GHG emissions but do not affect the estimation of fuel economy compliance in the test procedure.

NHTSA has established two phases of CAFE standards for passenger cars and light-duty trucks (Table 1). The first phase, covering model years 2017 through 2021, includes final standards that NHTSA estimates will result in a fleet-wide average of 40.3 mpg for light-duty vehicles in model year 2021 [*17*]. The second phase, covering model years 2022 through 2025, requires additional improvements leading to a fleet-wide average of 48.7 mpg for light-duty vehicles in model year 2025. Compliance with $CO_2$ emission and CAFE standards is calculated only after final model year vehicle production, with fleet-wide light-duty vehicle standards representing averages based on the sales volume of passenger cars and light-duty trucks for a given year. Because sales volumes are not known until after the end of the model year, EPA and NHTSA estimate future fuel economy based on the projected sales volumes of passenger cars and light-duty trucks.

The new $CO_2$ emissions and CAFE standards for passenger cars and light-duty trucks use an attribute-based standard that is determined by vehicle footprint—the same methodology that was used in setting the final rule for model year 2012 to 2016 light-duty vehicles. Footprint is defined as wheelbase size (the distance from the center of the front axle to the center of the rear axle), multiplied by average track width (the distance between the center lines of the tires) in square feet. The minimum requirements for $CO_2$ emissions and CAFE are production-weighted averages based on unique vehicle footprints in a manufacturer's fleet and are calculated separately for passenger cars and light-duty trucks (Figures 9 and 10), reflecting their different design capabilities. In general, as vehicle footprint increases, compliance requirements decline to account for increased vehicle size and load-carrying capability. Each manufacturer faces a unique combination of $CO_2$ emission and CAFE standards, depending on the number of vehicles produced and the footprints of those vehicles, separately for passenger cars and light-duty trucks.

For passenger cars, average fleet-wide compliance levels increase in stringency by 3.9 percent annually between model years 2017 and 2021 and by 4.7 percent annually between 2022 and 2025, based on the model year 2010 baseline fleet. In recognition of the challenge of improving the fuel economy and reducing $CO_2$ emissions of full-size pickup trucks while maintaining towing and payload capabilities, the average annual rate of increase in the stringency of light-duty truck standards is 2.9 percent from 2017 to 2021, with smaller light-duty trucks facing higher increases and larger light-duty trucks lower increases in compliance stringency. From 2022 to 2025, the average annual increase in compliance stringency for all light-duty trucks is 4.7 percent.

The $CO_2$ emissions and CAFE standards also include flexibility provisions for compliance by individual manufacturers, such as: (1) credit averaging, which allows credit transfers between a manufacturer's passenger car and light-duty truck fleets; (2) credit banking, which allows manufacturers to "carry forward" credits earned from exceeding the standards in earlier model years and to "carry back" credits earned in later model years to offset shortfalls in earlier model years; (3) credit trading between manufacturers who exceed their standards and those who do not; (4) air conditioning improvement credits that can be applied toward $CO_2$ emissions standards; (5) off-cycle credits for measurable improvements in $CO_2$ emissions and fuel economy that are not captured by the two-cycle test procedure used to measure emissions and fuel consumption; (6) $CO_2$ emissions "compliance multipliers" for electric, plug-in hybrid electric, compressed natural gas, and fuel cell vehicles through model year 2021; and (7) incentives for the use of hybrid electric and other advanced technologies in full-size pickup trucks.

Finally, flexibility provisions do not allow domestic passenger cars to deviate significantly from annual fuel economy targets. NHTSA retains a required minimum fuel economy level for

**Table 1. NHTSA projected average fleet-wide CAFE compliance levels (miles per gallon) for passenger cars and light-duty trucks, model years 2017-2025, based on the model year 2010 baseline fleet**

| Model year | Passenger cars | Light-duty trucks | Combined |
|---|---|---|---|
| 2017 | 39.6 | 29.1 | 35.1 |
| 2018 | 41.1 | 29.6 | 36.1 |
| 2019 | 42.5 | 30.0 | 37.1 |
| 2020 | 44.2 | 30.6 | 38.3 |
| 2021 | 46.1 | 32.6 | 40.3 |
| 2022 | 48.2 | 34.2 | 42.3 |
| 2023 | 50.5 | 35.8 | 44.3 |
| 2024 | 52.9 | 37.5 | 46.5 |
| 2025 | 55.3 | 39.3 | 48.7 |

**Figure 9. Projected average passenger car CAFE compliance targets (miles per gallon) by vehicle footprint (square feet), model years 2017-2025**

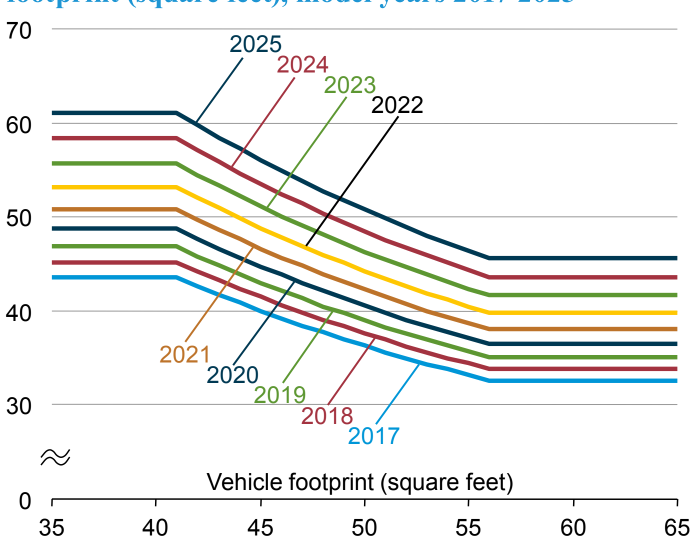
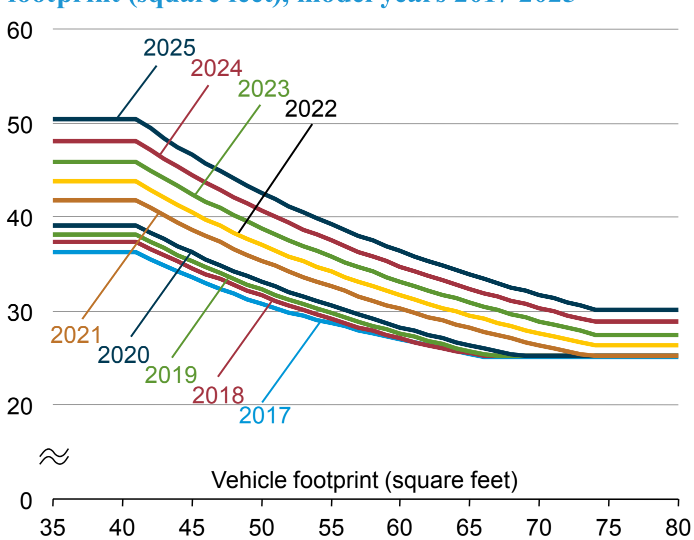



**Figure 10. Projected average light-duty truck CAFE compliance targets (miles per gallon) by vehicle footprint (square feet), model years 2017-2025**



domestically produced passenger cars by manufacturer that is the higher of 27.5 miles per gallon or 92 percent of the average fuel economy projected for the combined fleet of domestic and foreign passenger cars for sale in the United States. For example, the minimum standard for passenger cars sold by a manufacturer in 2025 would be 50.9 miles per gallon, based on the estimated fleet average passenger car fuel economy for that year.

The *AEO2013* Reference case includes the final CAFE standards for model years 2012 through 2016 (promulgated in March 2010) [*18*] and the standards for model years 2017 through 2025, with subsequent CAFE standards for years 2026-2040 vehicles calculated using 2025 levels of stringency. The *AEO2013* Reference case projects fuel economy values for passenger cars, light-duty trucks, and combined light-duty vehicles that differ from NHTSA projections. This variance is the result of a different distribution of the production of passenger cars and light-duty trucks by footprint as well as a different mix between passenger cars and light-duty trucks (Table 2). CAFE standards are included by using the equations and coefficients employed by NHTSA to determine unique fuel economy requirements based on footprint, along with the ability of manufacturers to earn flexibility credits toward compliance. The *AEO2013* Reference case projects sales of passenger cars and light-duty trucks by vehicle footprint with the key assumption that vehicle footprints are held constant by manufacturer in each light-duty vehicle size class.

## 2. Recent rulings on the Cross-State Air Pollution Rule and the Clean Air Interstate Rule

On August 21, 2012, the United States Court of Appeals for the District of Columbia Circuit announced its intent to vacate CSAPR, which it had stayed from going into effect earlier in 2012. CSAPR was to replace CAIR, which was in effect, by establishing emissions caps (levels) for sulfur dioxide ($SO_2$) and nitrogen oxides ($NO_X$) emissions from power plants in the eastern half of the United States. As a result of the court's action, the regulation of $SO_2$ and $NO_X$ emissions will continue to be administered under CAIR pending the promulgation of a valid replacement. *AEO2013* assumes that CAIR remains a binding regulation through 2040.

CAIR covers all fossil-fueled power plant units with nameplate capacity greater than 25 megawatts in 27 eastern states and the District of Columbia (Figure 11). Twenty-two states and the District of Columbia fall under the caps for both annual emissions of $SO_2$ and $NO_X$ and ozone season $NO_X$. Three states are controlled for only ozone season $NO_X$, and two states are controlled for only annual $SO_2$ and $NO_X$ emissions. The caps went into effect for $NO_X$ in 2009 and for $SO_2$ in 2010. Both caps are scheduled to be tightened again in 2015. *AEO2013* considered how the power sector would use the emissions allowance trading that EPA set up to lower compliance costs, including capturing the interplay of the $SO_2$ program for acid rain under the Clean Air Act Amendments Title IV and the CAIR program that uses the same allowances.

Although CSAPR shared some basic similarities with CAIR, there are key differences between the two programs. Generally, CSAPR had greater limitations on trading to ensure that emissions reductions would occur in all states; lower emissions caps; and more rapid phasing in of tighter emissions caps. CSAPR also did not allow carryover of banked allowances from the Acid Rain $SO_2$ and $NO_X$ Budget programs. Each program was aimed at substantial reductions of power sector $SO_2$ and $NO_X$ emissions.

*AEO2013* represents the limits on $SO_2$ and $NO_X$ emissions trading as specified by CAIR. The National Energy Modeling System (NEMS) includes the representation of emissions for both the CAIR and non-CAIR regions. In NEMS, power plants in both regions are required to submit allowances to account for their emissions as if covered by the rule. NEMS allows for power plants in the CAIR regions to trade $SO_2$ allowances with those plants in the non-CAIR region, but the $SO_2$ allowances are valued differently for each region. NEMS also allows for the banking of $SO_2$ and $NO_X$ allowances consistent with CAIR's provisions.

## 3. Nuclear waste disposal and the Waste Confidence Rule

Waste confidence is defined by the U.S. Nuclear Regulatory Commission (NRC) as a finding that spent nuclear fuel can be safely stored for decades beyond the licensed operating life of a reactor without significant environmental effects [*19*]. It enables the NRC to license reactors or renew their licenses without examining the effects of extended waste storage for each individual site pending ultimate disposal.

NRC's Waste Confidence Rule issued in August 1984 [*20*] included five findings:

1. Spent nuclear fuel can be disposed of safely in a mined geologic repository.
2. A mined geologic repository will be available when needed for disposal of spent nuclear fuel.
3. Until a mined geologic repository is available, spent nuclear fuel can be safely managed.
4. Spent nuclear fuel can be safely stored at reactors for 30 years without significant environmental impacts.
5. Storage will be made available for spent nuclear fuel onsite or offsite, if required.

### Table 2. *AEO2013* projected average fleet-wide CAFE compliance levels (miles per gallon) for passenger cars and light-duty trucks, model years 2017-2025

| Model year | Passenger cars | Light-duty trucks | Combined |
|---|---|---|---|
| 2017 | 40.1 | 30.1 | 34.7 |
| 2018 | 40.9 | 30.7 | 35.5 |
| 2019 | 42.6 | 30.9 | 36.4 |
| 2020 | 44.4 | 32.0 | 37.9 |
| 2021 | 46.4 | 33.8 | 39.8 |
| 2022 | 48.7 | 34.9 | 41.5 |
| 2023 | 51.3 | 36.5 | 43.6 |
| 2024 | 52.5 | 38.3 | 45.2 |
| 2025 | 55.0 | 40.0 | 47.3 |
| 2026-2040 | Projected stringency based on 2025 levels. | | |

The Waste Confidence Rule was updated in 1990 [*21*], reviewed in 1999, and updated again in 2010 [*22*].

In December 2010, with the termination of the repository program at Yucca Mountain, the Waste Confidence Rule was amended to state that spent nuclear fuel could be stored safely at reactor sites for 60 years following reactor shutdown. In June 2012, the U.S. Court of Appeals for the District of Columbia Circuit struck down the NRC's 2010 amendment of the Waste Confidence Rule, stating that the NRC should have analyzed the environmental consequences of never building a permanent waste repository, and that the discussion of potential leaks or fires at spent fuel pools was inadequate [*23*].

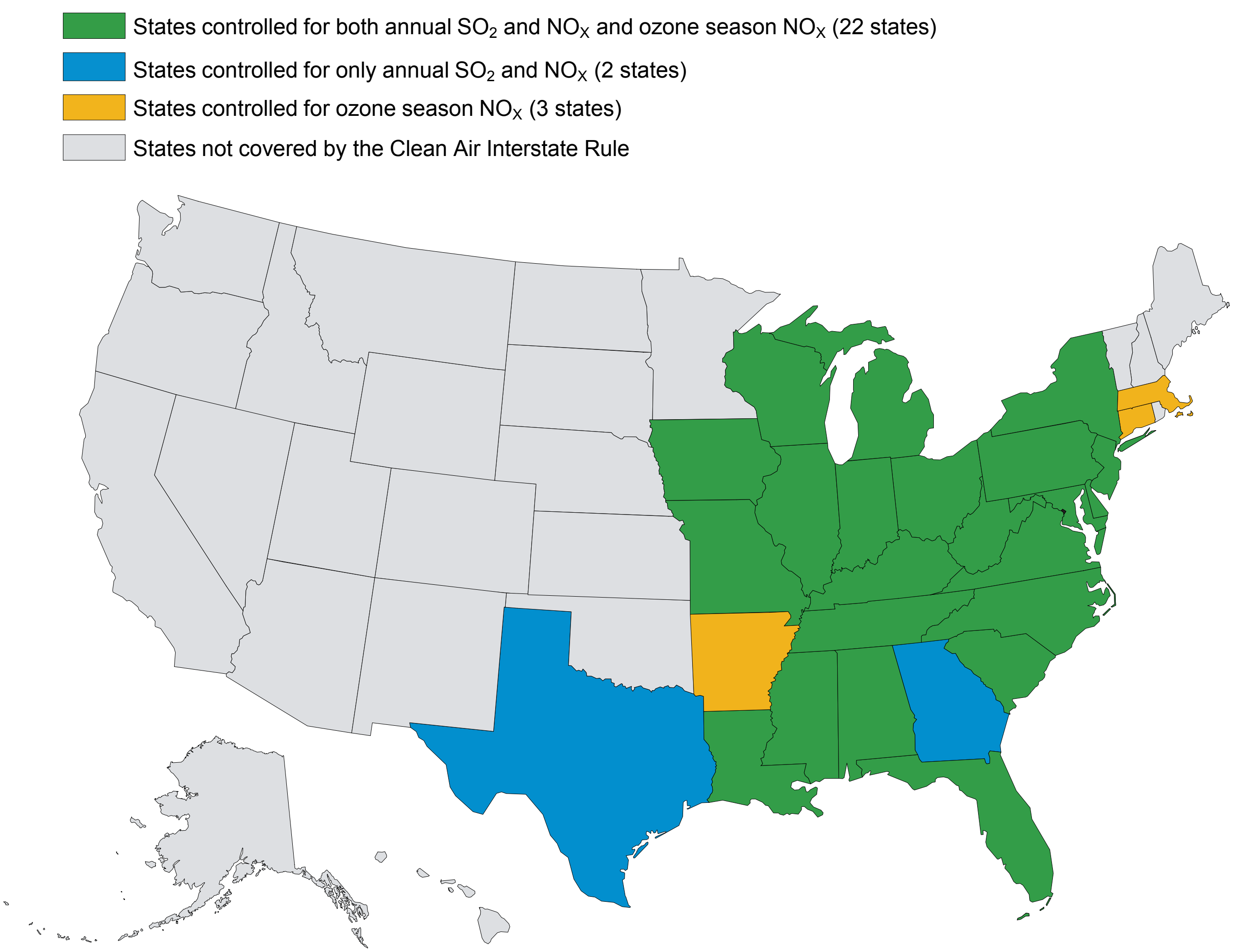
The NRC issued an order in August 2012 that suspended actions related to issuance of operating licenses and license renewals [*24*]. Currently, the NRC is analyzing the potential impacts on licensing reviews and developing a proposed path forward to meet the court's requirements. Until the NRC revises the Waste Confidence Rule, it will not issue reactor operating licenses or operating license renewals. Licensing reviews and proceedings will continue, but Atomic Safety and Licensing Board hearings will be suspended pending further NRC guidance. NRC expects to issue a revised Waste Confidence Rule within 2 years [*25*].

Reactors with license renewal applications under review by the NRC may continue to operate, even if their existing licenses expire, until the NRC can resolve the waste confidence issue and promulgate a revised rule. The regulation states: "If the licensee of a nuclear power plant licensed under 10 CFR 50.21(b) or 50.22 files a sufficient application for renewal of either an operating license or a combined license at least 5 years before the expiration of the existing license, the existing license will not be deemed to have expired until the application has been finally determined" [*26*]. There are currently 15 reactors with license renewal applications in various stages of review by the NRC that are subject to the August 2012 order that suspends licensing decisions.

For those reactors that have not submitted applications for license renewal, the first license expiration date would occur in 2020. Because it is anticipated by the NRC that the issues with the Waste Confidence Rule will be resolved within 2 years, well before 2020, the continued operation of those reactors should not be affected. The *AEO2013* Reference case assumes plants that have not submitted applications for license renewal will be unaffected.

Currently, utilities have the option to license reactors under either of two NRC rules. The NRC's Domestic Licensing of Production and Utilization Facilities rule defines a two-step process for obtaining an operating license [*27*]. First, a construction permit is

**Figure 11. States covered by CAIR limits on emissions of sulfur dioxide and nitrogen oxides**



issued, and then an operating license is issued. There are two U.S. reactors with current construction permits: Bellefonte Unit 1 and Watts Bar Unit 2. Both plants are owned by the Tennessee Valley Authority (TVA), which has announced that construction of Bellefonte Unit 1 will not proceed until fuel loading at Watts Bar Unit 2 is completed [*28*]. Neither reactor will be able to receive an operating license until the waste confidence issue is resolved, but construction may continue. TVA has not provided a projected date for commencement of operations at Bellefonte Unit 1, but it is unlikely that resolution of the issues associated with the Waste Confidence Rule will affect the operational date of Bellefonte Unit 1. Watts Bar Unit 2 was originally scheduled to go online in 2012, but delays in construction make it unlikely that it will be ready to begin operation before the issues with the Waste Confidence Rule can be resolved. *AEO2013* assumes that Watts Bar Unit 2 will come online in December 2015.

The NRC's "Licenses, Certifications, and Approvals for Nuclear Power Plants" rule defines a one-step process, whereby the construction permit and operating license are issued as a combined license (COL) [*29*]. Once an application for a COL is submitted, the utility may engage in certain pre-construction activities. To date, two plants, each with two reactors, have received COLs in 2012. Vogtle Units 3 and 4 and Summer Units 2 and 3 will both be unaffected by the issues with the Waste Confidence Rule. Once construction and all inspections are complete, the Vogtle and Summer plants may commence operations. For utilities that have submitted applications but have not received COLs, issuance of those licenses may be delayed. For COL applications currently under active review, it is possible that two—Levy County Units 1 and 2 and William States Lee III Units 1 and 2—may be delayed, based on their review status and the NRC's schedule for application reviews. The online dates for the units should be unaffected if issues with the Waste Confidence Rule are resolved within the next 2 years.

Based on EIA's analysis of the Waste Confidence Rule and ongoing proceedings, the *AEO2013* Reference case assumes that the issuance of new operating licenses will not be affected. *AEO2013* also assumes that the Waste Confidence Rule will not affect power uprates, because uprates do not increase the amount of spent nuclear fuel requiring storage, as confirmed in a public policy statement issued by the NRC [*30*].

### 4. Maximum Achievable Control Technology for industrial boilers

Section 112 of the CAA requires the regulation of air toxics through implementation of NESHAP for industrial, commercial, and institutional boilers [*31*]. The final regulations are also known as "Boiler MACT," where MACT is the Maximum Achievable Control Technology. Pollutants covered by the Boiler MACT regulations include control of hazardous air pollutants (HAPs), such as hydrogen chloride, mercury (Hg), and dioxin/furan, as well as carbon monoxide (CO), and particulate matter (PM) as surrogates for other HAPs. Boilers used for generating electricity are explicitly covered by the Mercury and Air Toxics Standards, also under Section 112 of the CAA, and are specifically excluded from Boiler MACT regulations.

The Final Rule for Boiler MACT was issued in March 2011; a partial Reconsideration Rule concerning limited technical corrections to the Final Rule was issued in December 2011, but it did not replace the Final Rule. The *AEO2013* Reference case assumes that the Final Rule and the partial Reconsideration Rules are in force. The finalized Boiler MACT rule was announced in December 2012, after the modeling work for *AEO2013* was completed. The provisions of the finalized Boiler MACT rule are less stringent than the provisions of the Final Rule and the partial Reconsideration Rule assumed in the Reference case. For *AEO2013*, the upgrade costs of Boiler MACT were implemented in the Macroeconomic Activity Module (MAM). Upgrade costs used are the "nonproductive costs," which are not associated with efficiency improvements. The upgrade costs are applied as an aggregated cost across all industries. Because of this aggregation of cost and the need for consistency across industries, the cost in the MAM is manifested as a reduction in shipments in the Industrial Demand Module. There is little difference in the cost of compliance for major sources between the March 2011 Final Rule and the December 2011 Reconsideration Rule, and there is no difference for area sources.

Boiler MACT has two compliance groups with different obligations: major source [*32*] and area source. A site that contains one or more boilers or process heaters that have the potential to emit 10 or more tons of any one HAP per year, or 25 tons or more of a combination of HAP per year, is a major source [*33*]. An emissions site that is not a major source is classified as an area source [*34*]. The characteristics of the site determine the compliance group of the boiler. Generally, compliance measures include regular maintenance and tuneups for smaller facilities and emission limits and performance tests for larger facilities. In the Reconsideration Rule, EIA calculations based on EPA estimates revealed that there were 14,111 existing major source boilers in 2011 [*35*]. Of those, calculations based on EPA estimates revealed that 16 percent burn fuels that potentially may subject them to specific emissions limits and annual performance tests. The existing number of affected area source boilers in 2011 was estimated at 189,450 by EIA, using data from EPA [*36*].

To comply with Boiler MACT, major source boilers and process heaters whose heat input is less than 10 million Btu per hour must receive tuneups every 2 years [*37*]. Most existing and new major source boilers or process heaters with heat inputs 10 million Btu per hour or greater that burn coal, biomass, liquid, or "other" gas are subject to emission limits on all five of the HAP listed above [*38*]. Larger major source boilers with heat input of 25 million Btu per hour or greater that burn coal, biomass, or residual oil must use a continuous emission monitoring system for PM [*39*]. Major source boilers with heat inputs of 10 million Btu per hour or more that burn natural gas or refinery gas, as well as metal process furnaces, are not subject to specific emissions limits or performance tests [*40*]. Existing major source boilers must comply with the Final Rule by March 21, 2014; new major source boilers must comply by May 20, 2011, or upon startup, whichever is later [*41*].

Area source natural gas-fired boilers are not subject to Boiler MACT. Area source coal-fired boilers whose heat input is less than 10 million Btu per hour and biomass-fired and liquid fuel-fired boilers of any size must receive a tuneup every 2 years. Existing area source boilers with heat input of 10 million Btu per hour or greater are subject to emissions limits, must receive an initial energy assessment, and must undergo performance tests every 3 years [*42*]. Existing and new coal-fired boilers must meet Hg and CO limits; new coal-fired boilers must also meet limits for PM. New oil-fired and biomass-fired boilers must meet emissions limits only for PM [*43*]. Existing area source boilers subject to an energy assessment and emissions limits must comply by March 21, 2014.

## 5. State renewable energy requirements and goals: Update through 2012

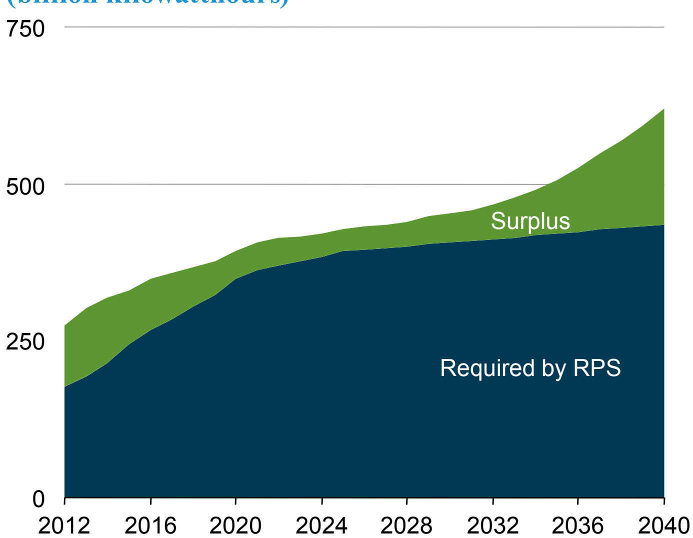
To the extent possible, *AEO2013* incorporates the impacts of state laws requiring the addition of renewable generation or capacity by utilities doing business in the states. Currently, 30 states and the District of Columbia have an enforceable renewable portfolio standard (RPS) or similar law (Table 3). Under such standards, each state determines its own levels of renewable generation, eligible technologies [*44*], and noncompliance penalties. *AEO2013* includes the impacts of all RPS laws in effect at the end of 2012 (with the exception of Alaska and Hawaii, because NEMS provides electricity market projections for the contiguous lower 48 states only). However, the projections do not include policies with either voluntary goals or targets that can be substantially satisfied with nonrenewable resources. In addition, NEMS does not treat fuel-specific provisions—such as those for solar and offshore wind energy—as distinct targets. Where applicable, such distinct targets (sometimes referred to as "tiers," "set-asides," or "carve-outs") may be subsumed into the broader targets, or they may not be included in the modeling because they could be met with existing capacity and/or projected growth based on modeled economic and policy factors.

In the *AEO2013* Reference case, states generally are projected to meet their ultimate RPS targets. The RPS compliance constraints in most regions are approximated, because NEMS is not a state-level model, and each state generally represents only a portion of one of the NEMS electricity regions. 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. In general, EIA has confirmed the states' requirements through original documentation, although the Database of State Incentives for Renewables & Efficiency was also used to support those efforts [*45*].

No new RPS programs were enacted over the past year; however, some states with existing RPS programs made modifications in 2012, as discussed below. The aggregate RPS requirement for the various state programs, as modeled in *AEO2013*, is shown in Figure 12. In 2025 the targets account for about 10 percent of U.S. electricity sales. The requirement is derived from the legal targets and projected sales and does not account for any of the discretionary or nondiscretionary waivers or limits on compliance found in most state RPS programs.

At present, most states are meeting or exceeding their required levels of renewable generation based on qualified generation [*46*]. A number of factors have helped to create an environment favorable for RPS compliance, including a surge of new RPS-qualified generation capacity timed to take advantage of federal incentives that either have expired or were scheduled to expire; significant reductions in the cost of renewable technologies like wind and solar; and generally reduced growth (or, in some cases, even contraction) of electricity sales. In addition to the availability of federal tax credits, which historically have gone through a cycle of expiration and renewal, renewable energy projects were given access to other options for federal support, including cash grants (also known as Section 1603 grants) and loan guarantees. The short-term availability of federal incentives has helped to make renewable capacity attractive to investors and helped utilities meet state requirements or potential future load growth in advance (that is, build ahead of time to take advantage of the federal incentives). The attractiveness of renewable projects to investors has also been supported by declining equipment costs for wind turbines and solar photovoltaic systems, as well as by improvements in the performance of those technologies. The declines in technology cost are, in themselves, the result of a complex set of interactions of policy, market, and engineering factors. Finally, most state RPS programs have targets that are tied to retail electricity sales; and with relatively slow growth in electricity sales in most parts of the country, the renewable generation that has entered service recently has gone further toward meeting the proportionally lower targets for absolute amounts of energy (that is, for kilowatthours of energy, as opposed to energy as a percent of sales).

**Figure 12. Total renewable generation required for combined state renewable portfolio standards and projected total achieved, 2012-2040 (billion kilowatthours)**



## Table 3. Renewable portfolio standards in the 30 states and District of Columbia with current mandates

| State | Target | Qualifying renewables | Qualifying other (thermal, efficiency, nonrenewable distributed generation, etc.) | Compliance mechanisms |
|---|---|---|---|---|
| AZ | 15% by 2025 | Solar, wind, biomass, hydropower, landfill gas (LFG), anaerobic digestion built after January 1, 1997 | Direct use of solar heat, ground-source heat pumps, and renewable-fueled combined heat and power (CHP), cogeneration, and fuel cells | Credit trading is allowed, with some bundling restrictions. Includes distributed generation requirement, starting at 5% of target in 2007, growing to 30% in 2012 and beyond. |
| CA | 33% by 2020 | Solar, wind, biomass, geothermal, LFG and municipal solid waste (MSW), small hydro, biodiesel, anaerobic digestion, and marine | Energy storage | Credit trading is allowed, with some restrictions. Renewable energy credit prices are capped at $50 per megawatthour. |
| CO | 30% by 2020 for investor-owned utilities; 33% by 2025 for electric cooperatives and municipal utilities serving more than 40,000 customers | Solar, wind, biomass, hydro, biomass, geothermal electric, and anaerobic digestion | Recycled energy | Credit trading is allowed. The distributed renewables requirement (30% of target) applies to investor-owned utilities. Generation from in-state and solar projects is eligible to earn credit multipliers, as is generation associated with certain projects that have specific ownership or transmission ties with small utilities, entities, or individuals. |
| CT | 27% by 2020 (23% renewables, 4% efficiency and CHP) | Solar, wind, hydro (with exceptions), LFG/MSW, anaerobic energy, marine | CHP/cogeneration | Credit trading is allowed. Obligated providers may comply via an alternative compliance payment of $55 per megawatthour. The target is made up of four source tiers with tier-specific targets. |
| DE | 25% by 2026 | Solar, wind, biomass, hydro, geothermal, LFG, anaerobic digestion, marine | Fuel cells, distributed generation | Credit trading is allowed. Credit multipliers are awarded for several compliance specifications, including generation from in-state distributed solar and renewable-fueled fuel cells and offshore wind. Target increases for some suppliers can be subject to a cost threshold. |
| DC | 20% by 2020 | Solar, wind, biomass, hydro, geothermal, LFG/MSW, marine | Cofiring | Credit trading is allowed. Target includes a solar-specific set-aside, equivalent to 2.5% of sales by 2023. Obligated providers may also comply via a tier-specific alternative compliance payment. |
| HI | 40% by 2030 | Solar, wind, biomass, hydro, geothermal, LFG/MSW, anaerobic digestion, marine, certain biofuels | Direct use of solar, ground-source heat pumps, ice storage, CHP/cogeneration, efficiency programs, fuel cells using renewable fuels, hydrogen | Credits cannot be traded. Eligibility of several of the "qualifying other" displacement technologies is restricted after 2015. Utility companies can calculate compliance over all utility affiliates. |
| IL | 25% by 2026 | Solar, wind, biomass, hydro, anaerobic digestion, biodiesel | None | Credit trading is allowed. Target includes specific requirements for wind, solar, and distributed generation. The procurement process is subject to a cost cap. |
| IA | 105 megawatts of eligible renewable resources | Wind, solar, some types of biomass and waste, small hydropower | None | Iowa's investor-owned utilities currently are in full compliance with this standard, achieved primarily through wind capacity. |

*(continued on next page)*

**Table 3. Renewable portfolio standards in the 30 states and District of Columbia with current mandates (continued)**

| State | Target | Qualifying renewables | Qualifying other (thermal, efficiency, nonrenewable distributed generation, etc.) | Compliance mechanisms |
|---|---|---|---|---|
| KS | 20% of each demand capacity by 2020 | Solar, wind, hydro, biomass, LFG, renewable-fueled fuel cells | Direct use of solar heat | Credit trading is allowed. Eligible in-state capacity counts for 1.1 times its actual capacity. |
| ME | 40% total by 2017, 10% by 2017 from new resources entering service in 2005 and beyond | Solar, LFG, wind, biomass, hydro, geothermal, MSW, marine | Fuel cells, CHP/ cogeneration | Credit trading is allowed. The Maine Public Utilities Commission sets an annually adjusted alternative compliance payment. Community-based generation projects are eligible to earn credit multipliers. |
| MD | 20% by 2022 | Solar, wind, biomass, geothermal, LFG/ MSW, anaerobic digestion, marine | Solar water heat, ground-source heat pumps | Credit trading allowed. The target includes a solar specific set-aside. Utilities may pay an alternative compliance payment in lieu of procuring eligible sources, with a tier-specific compliance schedule. |
| MA | 22.1% by 2020 (and an additional 1% per year thereafter) | Solar, wind, hydro, some biomass technologies, LFG/MSW, geothermal electric, anaerobic digestion, marine, renewable-fueled fuel cells | None | Credit trading is allowed. The target for new resources includes a solar-specific goal to achieve 400 megawatts of in-state solar capacity, which is translated into an annual target for obligated providers. Obligated providers may comply via an alternative compliance payment (ACP), which varies in level by the requirement class, although the ACP is designed to be higher than the cost of other compliance options. |
| MI | 10% by 2015, with specific new capacity goals for utilities that serve more than 1 million customers | Solar, wind, hydro, biomass, LFG/MSW, geothermal electric, anaerobic digestion, marine | CHP/cogeneration, coal with carbon capture and sequestration, and energy efficiency measures for up to 10 percent of a utility's sales obligation | Credit trading is allowed. Solar power receives a credit multiplier, while other generation and equipment features—such as peak generation, storage, and use of equipment manufactured in-state—can earn fractional bonus credits. |
| MN | 30% by 2020 (Xcel Energy) or 25% by 2025 (other utilities) | Solar, wind, hydro, biomass, LFG/MSW, anaerobic digestion | Hydrogen (generated from renewable sources), cofiring | Credit trading is allowed. Xcel's target must achieve 25 percent of sales specifically from wind and solar (with a 1-percent maximum for solar). State regulators can penalize noncompliance at the estimated cost of compliance. |
| MO | 15% by 2021 | Solar, wind, hydro, biomass, LFG/MSW, anaerobic digestion, ethanol, renewable-fueled fuel cells | None | Credit trading is allowed. Non-compliance payments are set at double the market rate for renewable energy credits. Solar must account for 20% of the annual target. |
| MT | 15% by 2015 | Solar, wind, hydro, geothermal, biomass, LFG | Compressed air storage | Credit trading is allowed, with a price cap of $10 per megawatthour. There are specific targets for community-based projects. |
| NV | 25% by 2025 | Solar, wind, hydro, geothermal, biomass, LFG/MSW | Waste tires, direct use of solar and geothermal heat, efficiency measures (which can account for one-quarter of the target in any given year) | Credit trading is allowed. Photovoltaics receives a credit premium, with an additional premium for customer-sited systems. |
| NH | 24.8% by 2025 | Solar, wind, small hydro, marine, LFG | Fuel cells, CHP, microturbines, direct use of solar heat, ground-source heat pumps | Credit trading is allowed, and utilities may pay into a fund in lieu of holding credits. The target comprises four separate compliance classes, broken out by technology. |

*(continued on next page)*

**Table 3. Renewable portfolio standards in the 30 states and District of Columbia with current mandates (continued)**

| State | Target | Qualifying renewables | Qualifying other (thermal, efficiency, nonrenewable distributed generation, etc.) | Compliance mechanisms |
|---|---|---|---|---|
| NJ | 20.38% by 2021, with an additional 4.1% solar by 2027 | Solar, wind, hydro, geothermal, LFG/ MSW, marine | None | Credit trading is allowed, with an alternative compliance payment set by state regulators. Solar and offshore wind are subject to separate requirements and have separate enforcement provisions. |
| NM | 20% by 2020 for investor-owned utilities, 10% by 2020 for cooperatives | Solar, wind, hydro, geothermal, LFG | Zero-emission technology, not including nuclear | Credit trading is allowed. The program cannot increase consumer costs beyond a threshold amount, increasing to 3 percent of annual costs by 2015. Technology minimums are established for wind, solar, and certain other resources. |
| NY | 29% by 2015 | Solar, wind, hydro, geothermal, biomass, LFG, marine | Direct use of solar heat, fuel cells | Credit trading is not allowed. Compliance is achieved through purchases by state authorities, funded by a surcharge on investor-owned utilities. Government-owned utilities may have their own, similar programs. |
| NC | 12.5% by 2021 for investor-owned utilities; 10% by 2018 for municipal and cooperative utilities | Solar, wind, small hydro, biomass, geothermal, LFG, marine | Direct use of solar heat, CHP, hydrogen, demand reduction | Credit trading is allowed. Impacts on customer costs are capped at specified levels. There are specific targets for solar and certain animal waste projects. |
| OH | 12.5% by 2024 | Solar, wind, hydro, biomass, geothermal, LFG/MSW | Energy storage, separate 12.5% target for “advanced energy technologies,” including coal mine methane, advanced nuclear, and efficiency | Credit trading is allowed. Alternative compliance payments are set by law and adjusted annually. There is a separate target for solar energy. |
| OR | 5% by 2025 for utilities with less than 1.5% of total sales; 10% by 2025 for utilities with less than 3% of total sales; 25% by 2025 for all others | Solar, wind, hydro, biomass, geothermal, LFG/MSW, marine | Hydrogen | Credit trading is allowed, with an alternative compliance payment and a limit on expenditures of 4% of annual revenue. Solar receives a credit multiplier. |
| PA | 18% by 2020 | Solar, wind, hydro, biomass, LFG/MSW | Certain advanced coal technologies, certain energy efficiency technologies, fuel cells, direct use of solar heat, ground-source heat pumps | Credit trading is allowed, with an alternative compliance payment. There are separate targets for solar and two different combinations of renewable, fossil, and efficiency technologies. |
| RI | 16% by 2019 | Solar, wind, hydro, biomass, geothermal, LFG, marine | None | Credit trading is allowed, with an alternative compliance payment. There is a separate target for 90 megawatts of new renewable capacity. |
| TX | 5,880 megawatts by 2018 | Solar, wind, hydro, biomass, geothermal, LFG, marine | Direct use of solar heat, ground-source heat pumps | Credit trading is allowed, with capacity targets converted to generation equivalents. State regulators may cap credit prices. 500 megawatts must be from resources other than wind. |
| WA | 15% by 2020 | Solar, wind, hydro, biomass, geothermal, LFG, marine | Combined heat and power | Credit trading is allowed, with an administrative penalty for noncompliance. |
| WV | 25% by 2025 | Solar, wind, hydro, biomass, geothermal, small hydro | Several coal and natural gas generation sources | Credit trading is allowed, with noncompliance assessments to be determined by state regulators. Renewable generation may receive credit multipliers, with additional credit earned for locating on abandoned strip mines. |

**Table 3. Renewable portfolio standards in the 30 states and District of Columbia with current mandates (continued)**

| State | Target | Qualifying renewables | Qualifying other (thermal, efficiency, nonrenewable distributed generation, etc.) | Compliance mechanisms |
|---|---|---|---|---|
| WI | 10% by 2015 | Solar, wind, hydro, biomass, geothermal, LFG/MSW, small hydro, marine | Pyrolysis [*47*], synthetic gas, direct use of solar or biomass heat, ground-source heat pumps | Credit trading is allowed. |

EIA projects that, overall, RPS-qualified generation will continue to meet or exceed aggregate targets for state RPS programs through 2040, as shown in Figure 12. Through the next decade, the surplus qualifying generation will decline gradually, as little additional qualifying capacity is added, allowing the targets to catch up with supply. By the end of the projection horizon, however, the surplus widens substantially as renewable generation technologies become increasingly competitive with conventional generation sources. It should be noted that the aggregate targets and qualifying generation shown in Figure 12 may mask significant regional variation, with some regions producing excess qualifying generation and others producing just enough to meet the requirement or even needing to import generation from adjoining regions to meet state targets. Furthermore, just because there is, in aggregate, more qualifying generation than is needed to meet the targets, this does not necessarily imply that projected generation would be the same without state RPS policies. State RPS policies may encourage investment in places where it otherwise would not occur, or would not occur in the amounts projected, even as other parts of the country see substantial growth above state targets, or even in their absence. It does, however, suggest that state RPS programs will not be the sole reason for future growth in renewable generation.

## Recent RPS modifications

A number of states modified their RPS programs in 2012, either through regulatory proceedings or through legislative action. These changes are reflected in Table 3. The changes affect some aspects of the laws and implementing regulations, but they do not have substantive effects on the representation of the RPS programs in *AEO2013*. Key changes include:

### California

California Assembly Bill 2196, which establishes requirements for certain biomass-based generation resources, requires that biomass-derived gas be produced on site or sourced from a common carrier pipeline that operates within the state. It also sets additional requirements related to the in-service date of a common carrier source and the ability to claim certain environmental benefits from the use of such sources.

### Maryland

The state enacted a series of bills that accelerate the solar-specific compliance schedule (while leaving the aggregate RPS target unchanged) and expand the tier 1 requirement category to include thermal output from certain animal waste and ground-source heat pumps.

### Massachusetts

The Department of Energy Resources issued final rules regarding the use of certain biomass resources to meet the RPS standard. Biomass facilities must meet certain conditions with regard to conversion technology and feedstock sourcing to be eligible for use in meeting the standard.

### New Hampshire

Senate Bill 218 allows certain thermal resources, including heat derived from qualified solar, geothermal, and biomass sources, to meet renewable energy targets. It also allows electricity produced from the cofiring of biomass in certain existing coal plants to meet the requirements. The bill also adjusts the total renewable energy target upward by 1 percentage point, to 24.8 percent by 2025.

### New Jersey

Senate Bill 1925 changed the compliance schedule for the solar component of the RPS. The revised law is implemented with a solar target of 3.47 percent of sales by 2021.

### Ohio

The legislature passed a set of laws that allow certain types of cogeneration facilities to qualify in meeting the RPS.

### 6. California Assembly Bill 32: Emissions cap-and-trade as part of the Global Warming Solutions Act of 2006

California's AB 32, the Global Warming Solutions Act of 2006, authorized the California Air Resources Board (CARB) to set California's overall GHG emissions reduction goal to its 1990 level by 2020 and establish a comprehensive, multi-year program to reduce GHG emissions in California, including a cap-and-trade program [*48*]. In addition to the cap-and-trade program, other authorized measures include the LCFS; energy efficiency goals and programs in transportation, buildings, and industry; combined heat and power goals; and RPS [*49*].

The cap-and-trade program features an enforceable cap on GHG emissions that will decline over time. CARB will distribute tradable allowances equal to the emissions allowed under the cap. Enforceable compliance obligations begin in 2013 for the electric power sector, including electricity imports, and for industrial facilities. Fuel providers must comply starting in 2015. All facilities that emit 25,000 metric tons carbon dioxide equivalent ($CO_2e$) or more are subject to cap-and-trade regulations. The only exception is that, starting in 2015, all importers of electricity from electric facilities outside of California will be subject to cap-and-trade regulations, even from facilities that emit less than 25,000 metric tons $CO_2e$ [*50*].

The most significant GHG covered under the program is $CO_2$, but the cap-and-trade program covers several other GHGs [*51*], including methane, nitrous oxide, perfluorocarbons, chlorofluorocarbons, nitrogen trifluoride, and sulfur hexafluoride [*52*]. In 2007, CARB determined that 427 million metric tons carbon dioxide equivalent ($MMTCO_2e$) was the total state-wide GHG emissions level in 1990 and, therefore, would be the 2020 emissions goal. CARB estimates that the implementation of the cap-and-trade program will reduce GHG emissions by between 18 and 27 $MMTCO_2e$ in 2020 [*53*].

The enforceable cap goes into effect in 2013, and there are three multi-year compliance periods:

- Compliance period 1 (2013-2014) includes sources of GHG emissions responsible for more than one-third of state-wide emissions.
- Compliance period 2 (2015-2017) covers sources of GHG emissions responsible for about 85 percent of state-wide emissions.
- Compliance period 3 (2018-2020) covers the same sources as Compliance Period 2 [*54*].

The electric power and industrial sectors are required to comply with the cap starting in 2013. Providers of natural gas, propane, and transportation fuels are required to comply starting in 2015, when the second compliance period begins. For the first compliance period, covered entities are required to submit allowances for up to 30 percent of their annual emissions in each year; however, at the end of 2014 they are required to account for all the emissions for which they were responsible during the 2-year period. Each covered entity can also use offsets to meet up to 8 percent of its compliance obligation. Offsets used as part of the program must be approved by CARB and can be canceled later by CARB for certain reasons (a provision known as "buyer liability").

A majority (51 percent) of the allowances [*55*] allocated over the initial 8 years of the program will be distributed through price containment reserves and auctions, which will be held quarterly when the program commences. CARB's first allowance auction was held in November 2012 [*56*]. Future auctions may be linked to Québec's cap-and-trade program [*57*]. Twenty-five percent of the allowances are allocated directly to electric utilities that sell electricity to consumers in the state. Seventeen percent of the allowances are allocated directly to affected industrial facilities in order to mitigate the economic impact of the cap on the industrial sector [*58*]. Allowance allocations for the industrial sector are based on output. Starting in 2013, the number of allowances allocated annually to the industrial sector declines linearly to 50 percent of the original total in 2020. The remaining 7 percent of the allowances issued in a given year go into a price containment reserve, to be used only if allowance prices rise above a set amount in quarterly auctions.

The AB 32 cap-and-trade provisions, which were incorporated only for the electric power sector in *AEO2012*, are more fully implemented in *AEO2013*, adding industrial facilities, refineries, fuel providers, and non-$CO_2$ GHG emissions. The allowance price, representing the incremental cost of complying with AB 32 cap-and-trade, is modeled in the NEMS Electricity Market Module via a region-specific emissions constraint. This allowance price, when added to the market fuel prices, results in higher effective fuel prices [*59*] in the demand sectors. Limited banking and borrowing, as well as a price containment reserve [*60*] and offsets, also have been modeled, providing some compliance flexibility and cost containment. NEMS macroeconomic effects are based on an energy-economy equilibrium that reacts to changes in energy prices and energy consumption; however, no macroeconomic effects are assumed explicitly from the AB 32 cap-and-trade provisions.

### 7. California low carbon fuel standard

The LCFS, administered by CARB [*61*], is designed to reduce by 10 percent the average carbon intensity of motor gasoline and diesel fuels sold in California from 2012 to 2020 through the increased sale of alternative "low-carbon" fuels. Regulated parties generally are the fuel producers and importers who sell motor gasoline or diesel fuel in California. The program is assumed to remain in place at 2020 levels from 2021 to 2040 in *AEO2013.* The carbon intensity of each alternative low-carbon fuel, based on life-cycle analyses conducted under the guidance of CARB for a number of approved fuel pathways, is calculated on an energy-equivalent basis, measured in grams of $CO_2$-equivalent emissions per megajoule.

*AEO2013* incorporates the LCFS by requiring that the average carbon intensity of motor fuels sold for use in California meets the carbon intensity targets. For the *AEO2013* Reference case, carbon intensity targets and the carbon intensities of alternative fuels were adapted from the "Third Notice of Public Availability of Modified Text and Availability of Additional Documents and

Information" [*62*]. Key uncertainties in the modeling of the LCFS are the availability of low-carbon fuels in California and what actions CARB may take if the LCFS is not met. In *AEO2013*, these uncertainties are addressed by assuming that fuel providers can purchase low-carbon credits if low-carbon fuels cannot be produced and sold at reasonable prices.

In December 2011, the U.S. District Court for the Eastern Division of California ruled in favor of several trade groups that claimed the LCFS violated the interstate commerce clause of the U.S. Constitution by seeking to regulate farming and ethanol production practices in other states. The court granted an injunction blocking enforcement of the LCFS by CARB [*63*]. In April 2012, the U.S. Ninth District Court of Appeals granted a stay of injunction while CARB appeals the original ruling [*64*]. Although the future of the LCFS program remains uncertain, the stay of the injunction requires that the program be enforced.

# Endnotes for Legislation and regulations

**Links current as of March 2013**

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43. U.S. Environmental Protection Agency, "National Emission Standards for Hazardous Air Pollutants for Area Sources: Industrial, Commercial, and Institutional Boilers, Final Rule," *Federal Register*, Vol. 76, No. 54 (Washington, DC: March 21, 2011), pp. 15,601-15,602, http://www.gpo.gov/fdsys/pkg/FR-2011-03-21/pdf/2011-4493.pdf.
44. The eligible technology, and even the definition of the technology or fuel category, will vary by state. For example, one state's definition of renewables may include hydroelectric power generation, while another's definition may not. Table 3 provides more detail on how the technology or fuel category is defined by each state.
45. More information about the Database of State Incentives for Renewables & Efficiency can be found at http://www.dsireusa.org/incentives.
46. Database of State Incentives for Renewables & Efficiency, http://www.dsireusa.org/rpsdata/index.cfm.

47. Pyrolysis is defined as the thermal decomposition of biomass at high temperatures (greater than 400 °F, or 200 °C) in the absence of air.
48. California Legislative Information, "Assembly Bill No. 32: California Global Warming Solutions Act of 2006" (Sacramento, CA: September 27, 2006), http://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=200520060AB32.
49. California Air Resources Board, "AB 32 Scoping Plan Functional Equivalent Document (FED)" (Sacramento, CA: May 16, 2012), http://www.arb.ca.gov/cc/scopingplan/fed.htm.
50. State of California, "Final Regulation Order, Subchapter 10 Climate Change, Article 5, Sections 95800 to 96023, Title 17, Article 5: California Cap on Greenhouse Gas Emissions and Market-Based Compliance Mechanisms" (Sacramento, CA: December 22, 2011), pp. 47-49, http://www.arb.ca.gov/regact/2010/capandtrade10/finalrevfro.pdf.
51. State of California, "Final Regulation Order, Subchapter 10 Climate Change, Article 5, Sections 95800 to 96023, Title 17, Article 5: California Cap on Greenhouse Gas Emissions and Market-Based Compliance Mechanisms" (Sacramento, CA: December 22, 2011), http://www.arb.ca.gov/regact/2010/capandtrade10/finalrevfro.pdf.
52. California Air Resources Board, "California Greenhouse Gas Emissions Inventory: 2000-2009" (Sacramento, CA: December 2011), p. 10, http://www.arb.ca.gov/cc/inventory/pubs/reports/ghg_inventory_00-09_report.pdf.
53. California Air Resources Board, "Updated Information Digest, Regulation to Implement the California Cap-and-Trade Program" (Sacramento, CA: December 14, 2011), p. 6, http://www.arb.ca.gov/regact/2010/capandtrade10/finuid.pdf.
54. For years 2021-2040 held constant in *AEO2013* at 2020 levels.
55. California Air Resources Board, "Appendix J, Allowance Allocation" (Sacramento, CA: October 18, 2010), p. J-12, http://www.arb.ca.gov/regact/2010/capandtrade10/capv4appj.pdf.
56. California Air Resources Board, "California Air Resources Board Quarterly Auction 1" (Sacramento, CA: November 19, 2012), http://www.arb.ca.gov/cc/capandtrade/auction/november_2012/auction1_results_2012q4nov.pdf.
57. California Environmental Protection Agency, "Press Release: California Applauds Québec on Adoption of Amended Cap-and-Trade Program" (Sacramento, CA: December 13, 2012), http://www.calepa.ca.gov/PressRoom/Releases/2012/Quebec.pdf.
58. See Assembly Bill 32, Section 38562(B)(8), http://www.leginfo.ca.gov/pub/05-06/bill/asm/ab_0001-0050/ab_32_bill_20060927_chaptered.pdf. The evaluation of "leakage risk" and the amount allocated to prevent leakage will be revisited by CARB during each of the periodic reviews of the cap-and-trade program, which will occur at least once every three-year compliance cycle.
59. A price that has been adjusted for allowance costs.
60. State of California, "Final Regulation Order, Subchapter 10 Climate Change, Article 5, Sections 95800 to 96023, Title 17, California Code of Regulations: California Cap on Greenhouse Gas Emissions and Market-Based Compliance Mechanisms" (Sacramento, CA: December 22, 2011), http://www.arb.ca.gov/regact/2010/capandtrade10/finalrevfro.pdf. Note: The final regulation states that reserves are held at 1 percent in compliance period 1, 4 percent in compliance period 2, and 7 percent in compliance period 3. For modeling purposes, post-2020 reserves are set to 0 percent.
61. State of California, "Final Regulation Order, Subchapter 10. Climate Change, Article 4. Regulations to Achieve Greenhouse Gas Reductions, Subarticle 7. Low Carbon Fuel Standard" (Sacramento, CA: January 13, 2010), http://www.arb.ca.gov/regact/2009/lcfs09/finalfro.pdf.
62. California Air Resources Board, "Third Notice of Public Availability of Modified Text and Availability of Additional Documents and Information" (Sacramento, CA: September 17, 2012), http://www.arb.ca.gov/regact/2011/lcfs2011/lcfs3rdnot.pdf.
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64. California Air Resources Board, "LCFS Enforcement Injunction is Lifted, All Outstanding Reports Now Due April 30, 2012" (Sacramento, CA: April 24, 2012), http://www.arb.ca.gov/fuels/lcfs/LCFS_Stay_Granted.pdf.

# Issues in focus

## Introduction

The "Issues in focus" section of the *Annual Energy Outlook (AEO)* provides an in-depth discussion on topics of special significance, including changes in assumptions and recent developments in technologies for energy production and consumption. Selected quantitative results are available in Appendix D. The first topic updates a discussion included in a number of previous *AEO*s that compared the Reference case to the results of two cases with different assumptions about the future course of existing energy policies. One case assumes the elimination of sunset provisions in existing energy policies; that is, the policies are assumed not to terminate as they would under current law. The other case assumes the extension or expansion of a selected group of existing policies—corporate average fuel economy (CAFE) standards, appliance standards, and production tax credits (PTCs)—in addition to the elimination of sunset provisions.

Other topics discussed in this section, as identified by numbered subsections below, include (2) oil price and production trends in *Annual Energy Outlook 2013 (AEO2013)*; (3) petroleum import dependence under a range of cases; (4) competition between coal and natural gas in the electric power sector; (5) nuclear power in *AEO2013*; and (6) the impact of natural gas liquids (NGL) growth.

The topics explored in this section represent current and emerging issues in energy markets. However, many of the topics discussed in previous *AEO*s also remain relevant today. Table 4 provides a list of titles from the 2012, 2011, and 2010 *AEO*s that are likely to be of interest to today's readers—excluding topics that are updated in *AEO2013*. The articles listed in Table 4 can be found on the U.S. Energy Information Administration (EIA) website at http://www.eia.gov/analysis/reports.cfm?t=128.

## 1. No Sunset and Extended Policies cases

### Background

The *AEO2013* Reference case is best described as a current laws and regulations case because it generally assumes that existing laws and regulations remain unchanged throughout the projection period, unless the legislation establishing them sets a sunset date or specifies how they will change. The Reference case often serves as a starting point for analysis of proposed changes in legislation or regulations. While the definition of the Reference case is relatively straightforward, there may be considerable interest in a variety of alternative cases that reflect updates or extensions of current laws and regulations. Areas of particular interest 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.

### Table 4. Key analyses from "Issues in focus" in recent *AEO*s

| *AEO2012* | *AEO2011* | *AEO2010* |
|---|---|---|
| Potential efficiency improvements and their impacts on end-use energy demand | Increasing light-duty vehicle greenhouse gas and fuel economy standards for model years 2017 to 2025 | Energy intensity trends in *AEO2010* |
| Energy impacts of proposed CAFE standards for light-duty vehicles, model years 2017 to 2025 | Fuel consumption and greenhouse gas emissions standards for heavy-duty vehicles | Natural gas as a fuel for heavy trucks: issues and incentives |
| Impacts of a breakthrough in battery vehicle technology | Potential efficiency improvements in alternative cases for appliance standards and building codes | Factors affecting the relationship between crude oil and natural gas prices |
| Heavy-duty natural gas vehicles | Potential of offshore crude oil and natural gas resources | Importance of low permeability natural gas reservoirs |
| Changing structure of the refining industry | Prospects for shale gas | U.S. nuclear power plants: continued life or replacement after 60? |
| Changing environment for fuel use in electricity generation | Cost uncertainties for new electric power plants | Accounting for carbon dioxide emissions from biomass energy combustion |
| Nuclear power in *AEO2012* | Carbon capture and storage: economics and issues | |
| Potential impact of minimum pipeline throughput constraints on Alaska North Slope oil production | Power sector environmental regulations on the horizon | |
| U.S. crude oil and natural gas resource uncertainty | | |
| Evolving Marcellus Shale gas resource estimates | | |

- Laws or regulations that call for periodic updating of initial specifications. Examples include appliance efficiency standards issued by the U.S. Department of Energy (DOE) and CAFE and greenhouse gas (GHG) emissions standards for vehicles issued by the National Highway Traffic Safety Administration (NHTSA) and the U.S. Environmental Protection Agency (EPA).
- Laws or regulations that allow or require the appropriate regulatory agency to issue new or revised regulations under certain conditions. Examples include the numerous provisions of the Clean Air Act that require EPA to issue or revise regulations if it finds that an environmental quality target is not being met.

Two alternative cases are discussed in this section to provide some insight into the sensitivity of results to scenarios in which existing tax credits or other policies do not sunset. 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. The cases examined here look only at federal laws or regulations and do not examine state laws or regulations.

## Analysis cases

The two cases prepared—the No Sunset case and the Extended Policies case—incorporate all the assumptions from the *AEO2013* Reference case, except as identified below. Changes from the Reference case assumptions include the following.

### No Sunset case

Tax credits for renewable energy sources in the utility, industrial, and buildings sectors, or for energy-efficient equipment in the buildings sector, are assumed to be extended, including the following:

- The PTC of 2.2 cents per kilowatthour and the 30-percent investment tax credit (ITC) available for wind, geothermal, biomass, hydroelectric, and landfill gas resources, assumed in the Reference case to expire at the end of 2012 for wind and 2013 for the other eligible resources, are extended indefinitely. On January 1, 2013, Congress passed a one-year extension of the PTC for wind and modified the qualification rules for all eligible technologies; these changes are not included in the *AEO2013* Reference case, which was completed in December 2012, but they are discussed in a box on page 22.
- For solar power investments, 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, personal tax credits for the purchase of renewable equipment, including photovoltaics (PV), are assumed to be extended indefinitely, as opposed to ending in 2016 as prescribed by current law. The business ITCs 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. On January 1, 2013, legislation was enacted to reinstate tax credits for energy-efficient homes and selected residential appliances. The tax credits that had expired on December 31, 2011, are now extended through December 31, 2013. This change is not included in the Reference case.
- In the industrial sector, the 10-percent ITC for combined heat and power (CHP) that ends in 2016 in the *AEO2013* Reference case [65] is assumed to be preserved through 2040, the end of the projection period.

### Extended Policies case

The Extended Policies case includes additional updates to federal equipment efficiency standards that were not considered in the Reference case or No Sunset case. Residential and commercial end-use technologies eligible for incentives in the No Sunset case are not subject to new standards. Other than those exceptions, the Extended Policies case adopts the same assumptions as the No Sunset case, plus the following:

- Federal equipment efficiency standards are assumed to be updated at periodic intervals, consistent with the provisions in existing law, at levels based on ENERGY STAR specifications or on the Federal Energy Management Program purchasing guidelines for federal agencies, as applicable. Standards are also introduced for products that currently are not subject to federal efficiency standards.
- Updated federal energy codes for residential and commercial buildings increase by 30 percent in 2020 compared to the 2006 International Energy Conservation Code in the residential sector and the American Society of Heating, Refrigerating and Air-Conditioning Engineers Building Energy Code 90.1-2004 in the commercial sector. Two subsequent rounds in 2023 and 2026 each add an assumed 5-percent incremental improvement to building energy codes. The equipment standards and building codes assumed for the Extended Policies case are meant to illustrate the potential effects of those policies on energy consumption for buildings. No cost-benefit analysis or evaluation of impacts on consumer welfare was completed in developing the assumptions. Likewise, no technical feasibility analysis was conducted, although standards were not allowed to exceed the “maximum technologically feasible” levels described in DOE’s technical support documents.
- The *AEO2013* Reference, No Sunset, and Extended Policies cases include both the attribute-based CAFE standards for light-duty vehicles (LDVs) in model year (MY) 2011 and the joint attribute-based CAFE and vehicle GHG emissions standards for MY 2012 to MY 2025. The Reference and No Sunset cases assume that the CAFE standards are then held constant at MY 2025 levels in subsequent model years, although the fuel economy of new LDVs continues to rise modestly over time. The

Extended Policies case modifies the assumption in the Reference and No Sunset cases, assuming continued increases in CAFE standards after MY 2025. CAFE standards for new LDVs are assumed to increase by an annual average rate of 1.4 percent.

- In the industrial sector, the ITC for CHP is extended to cover all properties with CHP, no matter what the system size (instead of being limited to properties with systems smaller than 50 megawatts as in the Reference case [66]), which may include multiple units. Also, the ITC is modified to increase the eligible CHP unit cap to 25 megawatts from 15 megawatts. These extensions are consistent with previously proposed legislation.

## Analysis results

The changes made to the Reference case assumptions in the No Sunset and Extended Policies cases generally lead to lower estimates for overall energy consumption, increased use of renewable fuels particularly for electricity generation and reduced energy-related carbon dioxide ($CO_2$) emissions. Because the Extended Policies case includes most of the assumptions in the No Sunset case but adds others, the effects of the Extended Policies case tend to be greater than those in the No Sunset case—but not in all cases, as discussed below. Although these cases show lower energy prices, because the tax credits and end-use efficiency standards lead to lower energy demand and reduce the costs of renewable technologies, appliance purchase costs are also affected. In addition, the government receives lower tax revenues as consumers and businesses take advantage of the tax credits.

### Energy consumption

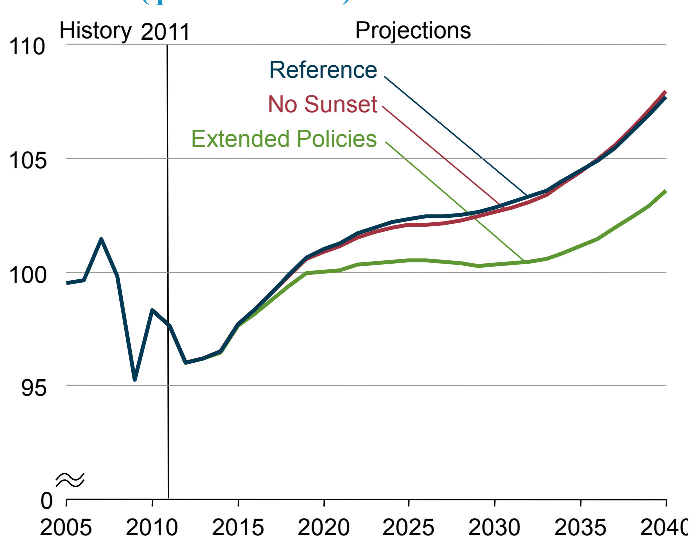
Total energy consumption in the No Sunset case is close to the level in the Reference case (Figure 13). Improvements in energy efficiency lead to reduced consumption in this case, but somewhat lower energy prices lead to relatively higher levels of consumption, partially offsetting the impact of improved efficiency. In 2040, total energy consumption in the Extended Policies case is 3.8 percent below the Reference case projection.

### Buildings energy consumption

Renewable distributed generation (DG) technologies (PV systems and small wind turbines) provide much of the buildings-related energy savings in the No Sunset case. Extended tax credits in the No Sunset case spur increased adoption of renewable DG, leading to 61 billion kilowatthours of onsite electricity generation from DG systems in 2025, compared with 28 billion kilowatthours in the Reference case. Continued availability of the tax credits results in 137 billion kilowatthours of onsite electricity generation in 2040 in the No Sunset case—more than three times the amount of onsite electricity generated in 2040 in the Reference case. Similar adoption of renewable DG occurs in the Extended Policies case. With the additional efficiency gains from assumed future standards and more stringent building codes, delivered energy consumption for buildings is 3.9 percent (0.8 quadrillion British thermal units [Btu]) lower in 2025 and 8.0 percent (1.7 quadrillion Btu) lower in 2040 in the Extended Policies case than in the Reference case. The reduction in 2040 is more than seven times as large as the 1.1-percent (0.2 quadrillion Btu) reduction in the No Sunset case.

Electricity use shows the largest reduction in the two alternative cases compared to the Reference case. Building electricity consumption is 1.3 percent and 5.8 percent lower, respectively, in the No Sunset and Extended Policies cases in 2025 and 2.1 percent and 8.7 percent lower, respectively, in 2040 than in the Reference case, as onsite generation continues to increase and updated standards affect a greater share of the equipment stock in the Extended Policies case. Space heating and cooling are affected by the assumed standards and building codes, leading to significant savings in energy consumption for heating and cooling in the Extended Policies case. In 2040, delivered energy use for space heating in buildings is 9.6 percent lower, and energy use for space cooling is 20.3 percent lower, in the Extended Policies case than in the Reference case. In addition to improved standards and codes, extended tax credits for PV prompt increased adoption, offsetting some of the costs for purchased electricity for cooling. New standards for televisions and for personal computers and related equipment in the Extended Policies case lead to savings of 28.3 percent and 31.8 percent, respectively, in residential electricity use for this equipment in 2040 relative to the Reference case. Residential and commercial natural gas use declines from 8.1 quadrillion Btu in 2011 to 7.8 quadrillion Btu in 2025 and 7.2 quadrillion Btu in 2040 in the Extended Policies case, representing a 2.2-percent reduction in 2025 and a 8.5-percent reduction in 2040 relative to the Reference case.

**Figure 13. Total energy consumption in three cases, 2005-2040 (quadrillion Btu)**




### Industrial energy consumption

The No Sunset case modifies the Reference case assumptions by extending the existing ITC for industrial CHP through 2040. The Extended Policies case starts from the No Sunset case and expands the credit to include industrial CHP systems of all sizes and raises the maximum credit that can be claimed from 15 megawatts of installed capacity to 25 megawatts. The changes result in 1.6 gigawatts of additional industrial CHP capacity in the No Sunset case compared with the Reference case in 2025 and 3.5 gigawatts of additional capacity in 2040. From 2025 through 2040, more CHP capacity is installed in the No Sunset case than in the Extended Policy case. CHP capacity is 0.3 gigawatts higher in the No Sunset Case than in the Extended Policies Case in 2025 and 1.2 gigawatts higher in 2040. Although the Extended Policies case includes a higher tax benefit for CHP than the No Sunset case, which by itself provides greater incentive to build CHP capacity, electricity prices are lower in the Extended Policies case than in the No Sunset case starting around 2020, and the difference increases over time. Lower electricity prices, all else equal, reduce the economic attractiveness of CHP. Also, the median size of industrial CHP units size is 10 megawatts [*67*], and many CHP systems are well within the 50-megawatt total system size, which means that relaxing the size constraint is not as strong an incentive for investment as is allowing the current tax credit for new CHP investments to continue after 2016.

Natural gas consumption averages 9.7 quadrillion Btu per year in the industrial sector from 2011 to 2040 in the No Sunset case—about 0.1 quadrillion Btu, or 0.9 percent, above the level in the Reference case. Over the course of the projection, the difference in natural gas consumption between the No Sunset case and the Reference case is small but increases steadily. In 2025, natural gas consumption in the No Sunset case is approximately 0.1 quadrillion Btu higher than in the Reference Case, and in 2040 it is 0.2 quadrillion Btu higher. Natural gas consumption in the Extended Policies case is virtually the same as in the No Sunset case through 2030. After 2030, refinery use of natural gas stabilizes in the Extended Policies case as continued increases in CAFE standards reduce demand for petroleum products.

**Transportation energy consumption**

The Extended Policies case differs from the Reference and No Sunset cases in assuming that the CAFE standards recently finalized by EPA and NHTSA for MY 2017 through 2025 (which call for a 4.1-percent annual average increase in fuel economy for new LDVs) are extended through 2040 with an assumed average annual increase of 1.4 percent. Sales of vehicles that do not rely solely on a gasoline internal combustion engines for both motive and accessory power (including those that use diesel, alternative fuels, or hybrid electric systems) play a substantial role in meeting the higher fuel economy standards after 2025, growing to almost 72 percent of new LDV sales in 2040, compared with about 49 percent in the Reference case.

LDV energy consumption declines in the Reference case from 16.1 quadrillion Btu (8.7 million barrels per day) in 2011 to 14.0 quadrillion Btu (7.7 million barrels per day) in 2025 as a result of the increase in CAFE standards. Extension of the increases in CAFE standards in the Extended Policies case further reduces LDV energy consumption to 11.9 quadrillion Btu (6.5 million barrels per day) in 2040, or about 8 percent lower than in the Reference case. Petroleum and other liquid fuels consumption in the transportation sector is virtually identical through 2025 in the Reference and Extended Policies cases but declines in the Extended Policies case from 13.3 million barrels per day in 2025 to 12.3 million barrels per day in 2040, as compared with 13.0 million barrels per day in 2040 in the Reference case (Figure 14).

**Renewable electricity generation**

The extension of tax credits for renewables through 2040 would, over the long run, lead to more rapid growth in renewable generation than in the Reference case. When the renewable tax credits are extended without extending energy efficiency standards, as assumed in the No Sunset case, there is a significant increase in renewable generation in 2040 compared to the Reference case (Figure 15). Extending both renewable tax credits and energy efficiency standards in the Extended Policies case results in more modest growth

**Figure 14. Consumption of petroleum and other liquids for transportation in three cases, 2005-2040 (million barrels per day)**

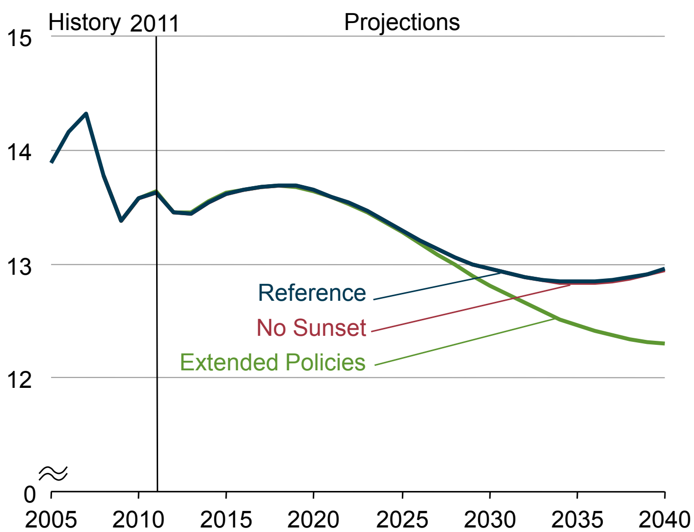
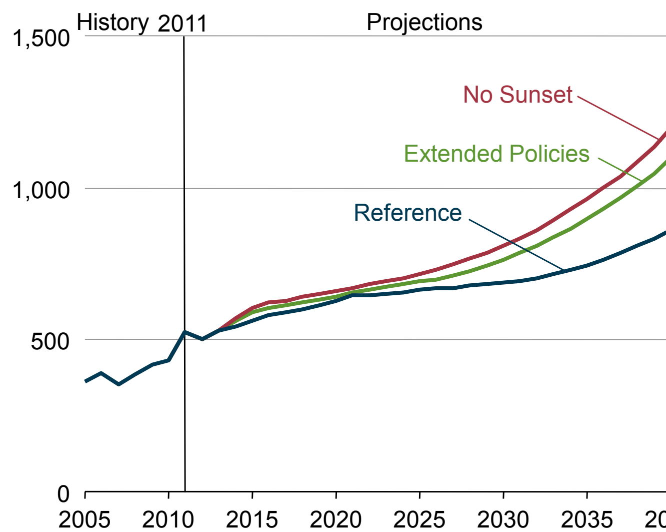



**Figure 15. Renewable electricity generation in three cases, 2005-2040 (billion kilowatthours)**



in renewable generation, because renewable generation is a significant 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.

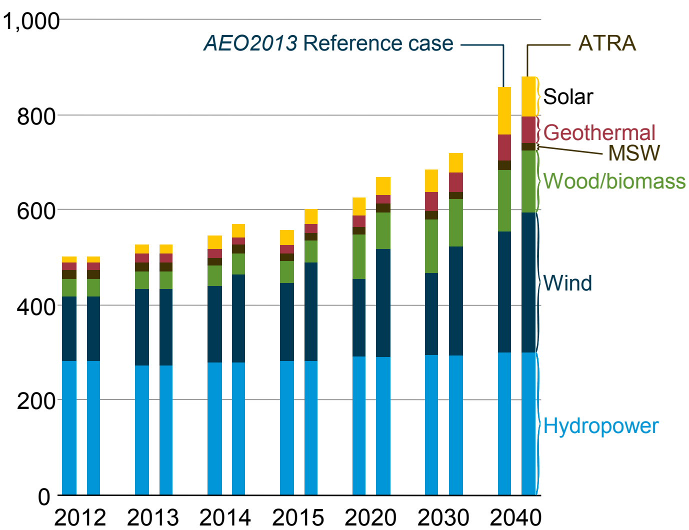
The *AEO2013* Reference case does not reflect the provisions of the American Taxpayer Relief Act of 2012 (P.L. 112-240) passed on January 1, 2013 [*68*], which extends the PTCs for renewable generation beyond what is included in the *AEO2013* Reference case. While this legislation was completed too late for inclusion in the Reference case, EIA did complete an alternative case that examined key energy-related provisions of that legislation, the most important of which is the extension of the PTC for renewable generation. A brief summary of those results is presented in the box, "Effects of energy provisions in the American Taxpayer Relief Act of 2012."

**Effects of energy provisions in the American Taxpayer Relief Act of 2012**

On January 1, 2013, Congress passed the American Taxpayer Relief Act of 2012 (ATRA). The law, among other things, extended several provisions for tax credits to the energy sector. Although the law was passed too late to be incorporated in the *Annual Energy Outlook 2013 (AEO2013)* Reference case, a special case was prepared to analyze some of its key provisions, including the extension of tax credits for utility-scale renewables, residential energy efficiency improvements, and biofuels [*69*]. The analysis found that the most significant impact on energy markets came from extending the production tax credits (PTCs) for utility-scale wind, and from changing the PTC qualification criteria from being in service on December 31, 2013, to being under construction by December 31, 2013, for all eligible utility-scale technologies. Although there is some uncertainty about what criteria will be used to define "under construction," this analysis assumes that the effective length of the extension is equal to the typical project development time for a qualifying project. For wind, the effective extension is 3 years.

Compared with the *AEO2013* Reference case, ATRA increases renewable generation, primarily from wind (Figure 16). Renewable generation in 2040 is about 2 percent higher in the ATRA case than in the Reference case, with the greatest growth occurring in the near term. In 2016, renewable generation in the ATRA case exceeds that in the Reference case by nearly 9 percent. Almost all the increase comes from wind generation, which in 2016 is about 34 percent higher in the ATRA case than in the Reference case. In 2040, however, wind generation is only 17 percent higher than projected in the Reference case. These results indicate that, while the short-term extension does result in additional wind generation capacity, some builds that otherwise would occur later in the projection period are moved up in time to take advantage of the extended tax credit. The increase in wind generation partially displaces other forms of generation in the Reference case, both renewable and nonrenewable—particularly solar, biomass, coal, and natural gas.

**Figure 16. Renewable electricity generation in two cases, 2012-2040 (billion kilowatthours)**




ATRA does not have significant effects on electricity or delivered natural gas prices and generally does not result in a difference of more than 1 percent either above or below Reference case prices. In the longer term (beyond 2020), electricity and natural gas prices generally both are slightly lower in the ATRA case, as increased wind capacity reduces variable fuel costs in the power sector and reduces the demand for natural gas.

Other ATRA provisions analyzed had minimal impact on all energy measures, primarily limited to short-term reductions in renewable fuel prices and a one-year window for residential customers to get tax credits for certain efficiency expenditures. Provisions of the act not addressed in this analysis are likely to have only modest impacts because of their limited scale, scope, and timing.

In the No Sunset and Extended Policies cases, renewable generation more than doubles from 2011 to 2040, as compared with a 64-percent increase in the Reference case. In 2040, the share of total electricity generation accounted for by renewables is between 22 and 23 percent in both the No Sunset and Extended Policies cases, as compared with 16 percent in the Reference case.

Construction of wind-generation units slows considerably in the Reference case from recent construction rates, following the assumed expiration of the tax credit for wind power in 2012. The combination of slow growth in electricity demand, little impact from state-level renewable generation requirements, and low prices for competing fuels like natural gas keeps growth relatively low until around 2025, when load growth finally catches up with installed capacity, and natural gas prices increase to a level at which wind is a cost-competitive option in some regions. Extending the PTC for wind spurs a brief surge in near-term development by 2014, but the factors that limit development through 2025 in the Reference case still largely apply, and growth from 2015 to about 2025 is slow, in spite of the availability of tax credits during the 10-year period. When the market picks up again after 2025, availability of the tax credits spurs additional wind development over Reference case levels. Wind generation in the No Sunset case is about 27 percent higher than in the Reference case in 2025 and 86 percent higher in 2040.

In the near term, the continuation of tax credits for solar generation results in a continuation of recent growth trends for this resource. The solar tax credits are assumed to expire in 2016 in the Reference case, after which the growth of solar generation slows significantly. Eventually, economic conditions become favorable for utility-scale solar without the federal tax credits, and the growth rate picks up substantially after 2025. With the extension of the ITC, growth continues throughout the projection period. Solar generation in the No Sunset case in 2040 is more than 30 times the 2011 level and more than twice the level in 2040 in the Reference case.

The impacts of the tax credit extensions on geothermal and biomass generation are mixed. Although the tax credits do apply to both geothermal and biomass resources, the structure of the tax credits, along with other market dynamics, makes wind and solar projects relatively more attractive. Over most of the projection period, geothermal and biomass generation are lower with the tax credits available than in the Reference case. In 2040, generation from both resources in the No Sunset and Extended Policies cases is less than 10 percent below the Reference case levels. However, generation growth lags significantly through 2020 with the tax credit extensions, and generation in 2020 from both resources is about 20 percent lower in the No Sunset and Extended Policy cases than in the Reference case.

After 2025, renewable generation in the No Sunset and Extended Policies cases starts to increase more rapidly than in the Reference case. As a result, generation from nuclear and fossil fuels is below Reference case levels. Natural gas represents the largest source of displaced generation. In 2040, electricity generation from natural gas is 13 percent lower in the No Sunset case and 16 percent lower in the Extended Policies case than in the Reference case (Figure 17).

**Energy-related $CO_2$ emissions**

In the No Sunset and Extended Policies cases, lower overall fossil energy use leads to lower levels of energy-related $CO_2$ emissions than in the Reference case. In the Extended Policies case, the emissions reduction is larger than in the No Sunset case. From 2011 to 2040, energy-related $CO_2$ emissions are reduced by a cumulative total of 4.6 billion metric tons (a 2.8-percent reduction over the period) in the Extended Policies case relative to the Reference case projection, as compared with 1.7 billion metric tons (a 1.0-percent reduction over the period) in the No Sunset case (Figure 18). The increase in fuel economy standards assumed for new LDVs in the Extended Policies case is responsible for 11.4 percent of the total cumulative reduction in $CO_2$ emissions from 2011 to 2040 in comparison with the Reference case. The balance of the reduction in $CO_2$ emissions is a result of greater improvement in appliance efficiencies and increased penetration of renewable electricity generation.

Most of the emissions reductions in the No Sunset case result from increases in renewable electricity generation. Consistent with current EIA conventions and EPA practice, emissions associated with the combustion of biomass for electricity generation are not counted, because they are assumed to be balanced by carbon absorption when the plant feedstock is grown. Relatively small incremental reductions in emissions are attributable to renewables in the Extended Policies case, mainly because electricity demand is lower than in the Reference case, reducing the consumption of all fuels used for generation, including biomass.

In both the No Sunset and Extended Policies cases, water heating, space cooling, and space heating together account for most of the emissions reductions from Reference case levels in the buildings sector. In the industrial sector, the Extended Policies case projects reduced emissions as a result of decreases in electricity purchases and petroleum use.

**Figure 17. Electricity generation from natural gas in three cases, 2005-2040 (billion kilowatthours)**

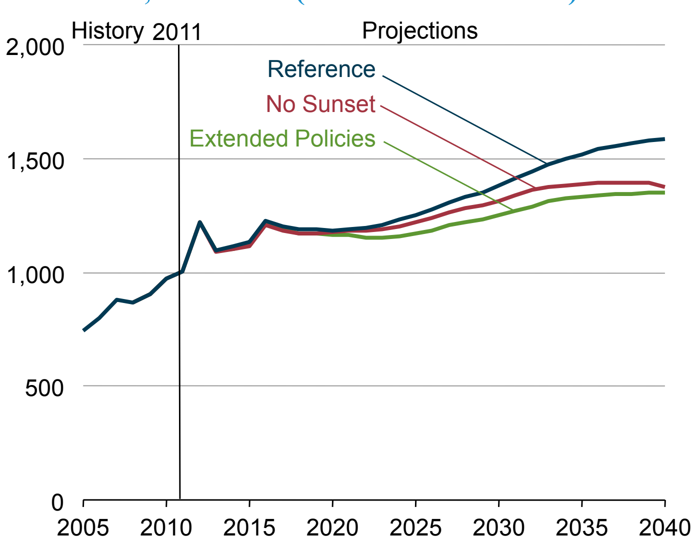
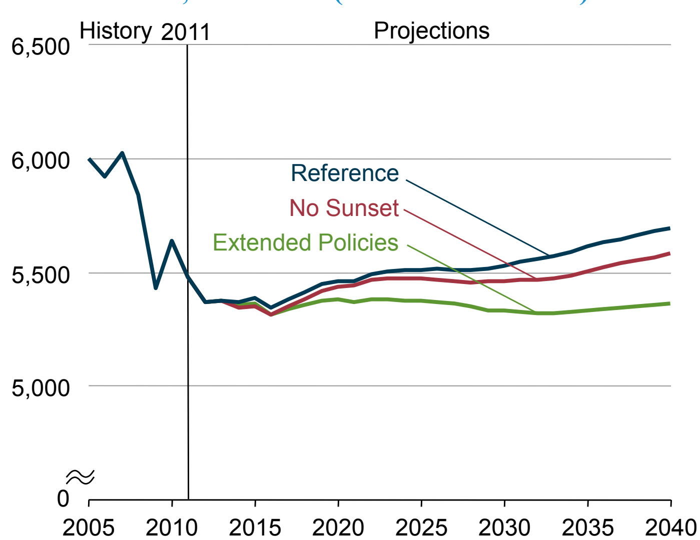



**Figure 18. Energy-related carbon dioxide emissions in three cases, 2005-2040 (million metric tons)**



**Energy prices and tax credit payments**

With lower levels of fossil energy use and more consumption of renewable fuels stimulated by tax credits in the No Sunset and Extended Policies cases, energy prices are lower than in the Reference case. In 2040, average delivered natural gas prices (2011 dollars) are $0.29 per million Btu (2.7 percent) and $0.59 per million Btu (5.4 percent) lower in the No Sunset and Extended Policies cases, respectively, than in the Reference case (Figure 19), and electricity prices are 3.9 percent and 6.3 percent lower than in the Reference case (Figure 20).

The reductions in energy consumption and $CO_2$ emissions in the Extended Policies case are accompanied by higher equipment costs for consumers and revenue reductions for the U.S. government. From 2013 to 2040, residential and commercial consumers spend, on average, an additional $20 billion per year (2011 dollars) for newly purchased end-use equipment, DG systems, and residential building shell improvements in the Extended Policies case as compared with the Reference case. On the other hand, residential and commercial customers save an average of $30 billion per year on energy purchases.

Tax credits paid to consumers in the buildings sector (or, from the government's perspective, reduced revenue) in the No Sunset case average $4 billion (2011 dollars) more per year than in the Reference case, which assumes that existing tax credits expire as currently scheduled, mostly by 2016.

The largest response to federal tax incentives for new renewable generation is seen in the No Sunset case, with extension of the PTC and the 30-percent ITC resulting in annual average reductions in government tax revenues of approximately $2.3 billion from 2011 to 2040, as compared with $650 million per year in the Reference case.

## 2. Oil price and production trends in *AEO2013*

The benchmark oil price in *AEO2013* is based on spot prices for Brent crude oil (commonly cited as Dated Brent in trade publications), an international benchmark for light sweet crude oil. The West Texas Intermediate (WTI) price has diverged from Brent and other benchmark prices over the past few years as a result of rapid growth in U.S. midcontinent and Canadian oil production, which has overwhelmed the transportation infrastructure needed to move crude oil from Cushing, Oklahoma, where WTI is quoted, to the Gulf Coast. EIA expects the WTI discount to the Brent price level to decrease over time as additional pipeline projects come on line, and will continue to report WTI prices (a critical reference point for the value of growing production in the U.S. midcontinent), as well as imported refiner acquisition costs (IRAC).

*AEO2013* projections of future oil supply include two broad categories: petroleum liquids and other liquid fuels. The term petroleum liquids refers to crude oil and lease condensate—which includes tight oil, shale oil, extra-heavy crude oil, and bitumen (i.e., oil sands, either diluted or upgraded), plant condensate, natural gas plant liquids (NGPL), and refinery gain. The term other liquids refers to oil shale (i.e., kerogen-to-liquids), gas-to-liquids (GTL), coal-to-liquids (CTL), and biofuels (including biomass-to-liquids).

The key factors determining long-term supply, demand, and prices for petroleum and other liquids can be summarized in four broad categories: the economics of non-Organization of the Petroleum-Exporting Countries (OPEC) petroleum liquids supply; OPEC investment and production decisions; the economics of other liquids supply; and world demand for petroleum and other liquids.

To reflect the significant uncertainty associated with future oil prices, EIA develops three price cases that examine the potential impacts of different oil price paths on U.S. energy markets (Figure 21). The three price cases are developed by adjusting the four key factors described above. The following sections discuss the adjustments made in *AEO2013*. Each price case represents one of

**Figure 19. Average delivered prices for natural gas in three cases, 2005-2040 (2011 dollars per million Btu)**

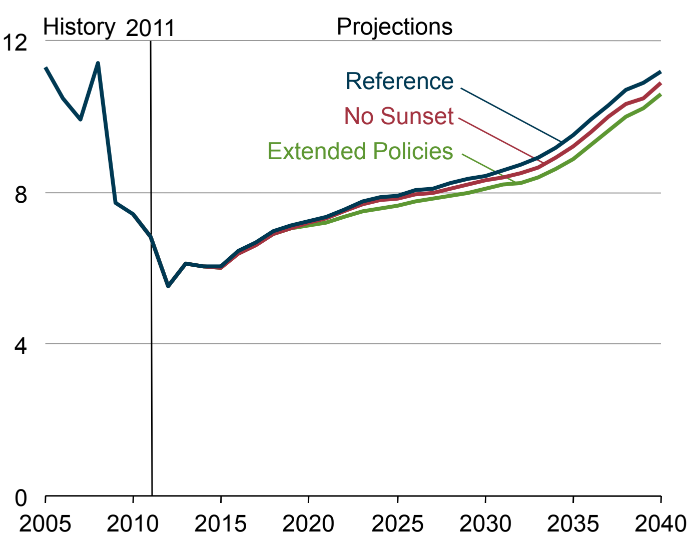
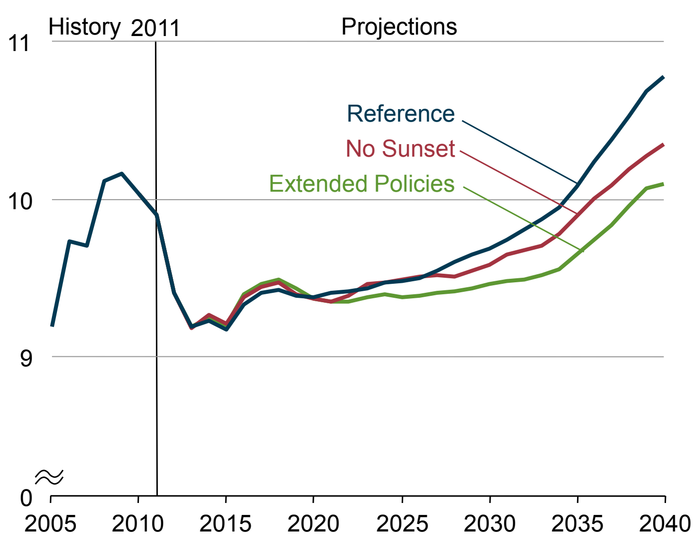



**Figure 20. Average electricity prices in three cases, 2005-2040 (2011 cents per kilowatthour)**



potentially many combinations of supply and demand that would result in the same price path. EIA does not assign probabilities to any of the oil price cases.

Because EIA's oil price paths represent market equilibrium between supply and demand in terms of annual average prices, they do not show the price volatility that occurs over days, months, or years. As a frame of reference, over the past two decades, volatility within a single year has averaged about 30 percent [*70*]. Although that level of volatility could continue, the alternative oil price cases in *AEO2013* assume smaller near-term price variation than in previous *AEO*s, because larger near-term price swings are expected to lead to market changes in supply or demand that would dampen the price.

The *AEO2013* oil price cases represent internally consistent scenarios of world energy production, consumption, and economics. One interesting outcome of the three oil price cases is that, although the price paths diverge, interactions among the four key factors lead to nearly equal total volumes of world liquids supply in the three cases in the 2030 timeframe (Figure 22).

### Reference case

Among the key factors defining the Reference case are the Organization for Economic Cooperation and Development (OECD) and non-OECD gross domestic product (GDP) growth rates and liquid fuels consumption per dollar of GDP. Both the OECD and non-OECD growth rates and liquids fuels consumption per dollar of GDP decline over the projection period in the Reference case. OPEC continues restricting production in a manner that keeps its market share of total liquid fuels production between 39 percent and 43 percent for most of the projection, rising to 43 percent in the final years. Most other liquid fuels production technologies are economical at Reference case prices. In the Reference case, the Brent price declines to $96 per barrel in 2015 and then increases over the remainder of the period, to $163 per barrel in 2040, as a result of demand increases and supply pressures.

OPEC production in the Reference case grows from 35 million barrels per day in 2011 to 48 million barrels per day in 2040 (Figure 23). Although the OPEC resource base is sufficient to support much higher production levels, the OPEC countries have an incentive to restrict production in order to support higher prices and sustain revenues in the long term. The Reference case assumes that OPEC will maintain a cohesive policy of limiting supply growth, rather than maximizing total annual revenues. The Reference case also assumes that no geopolitical events will cause prolonged supply shocks in the OPEC countries that could further limit production growth.

Non-OPEC petroleum production grows significantly in the early years of the Reference case projection, to 55 million barrels per day in 2020 from 50 million barrels per day in 2011, primarily as a result of increased production from tight oil

**Figure 21. Annual average spot price for Brent crude oil in three cases, 1990-2040 (2011 dollars per barrel)**

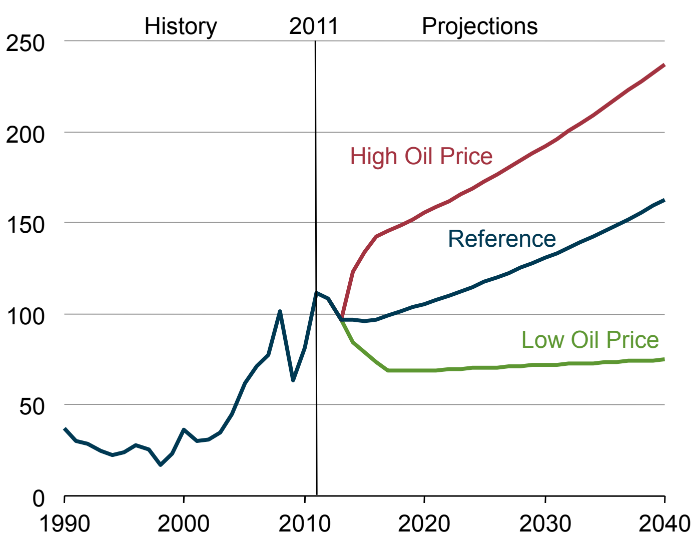



**Figure 22. World petroleum and other liquids supply in three cases, 1990-2040 (million barrels per day)**

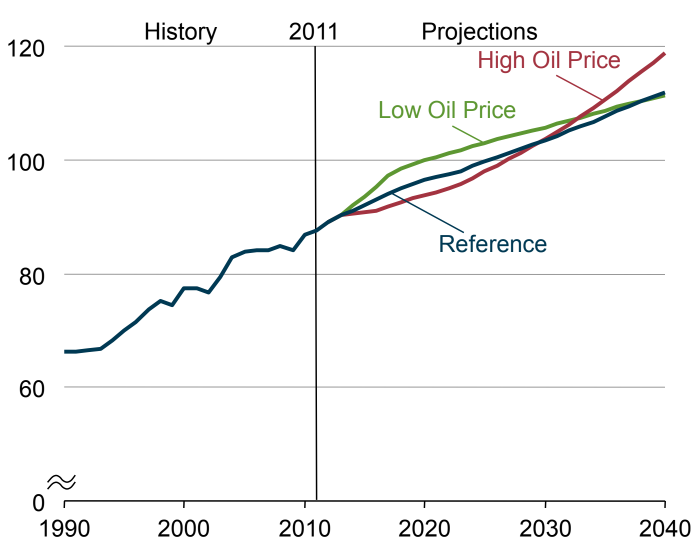
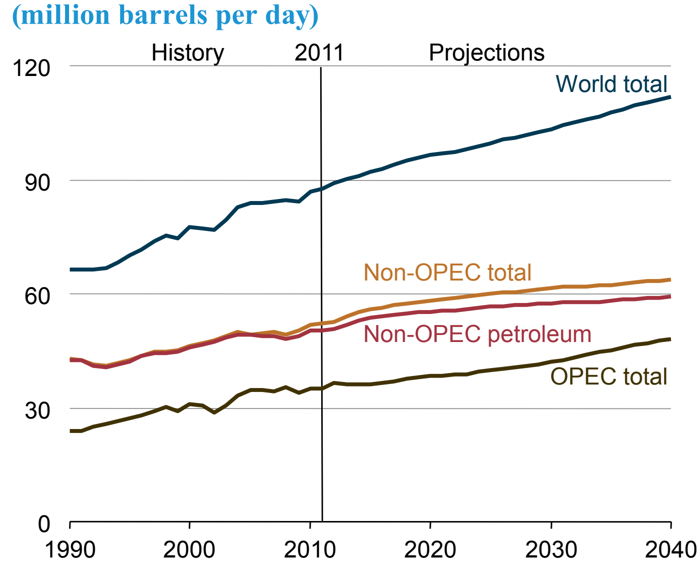



**Figure 23. World petroleum and other liquids supply by source in the Reference case, 1990-2040 (million barrels per day)**



formations. After 2020, production growth continues at a slower pace, adding another 4 million barrels per day to net production in 2040, with production from new wells increasing slightly faster than the decline in production from existing wells. The growth in non-OPEC production results primarily from the development of new fields and the application of new technologies, such as enhanced oil recovery (EOR), horizontal drilling, and hydraulic fracturing, which increase recovery rates from existing fields. The average cost per barrel of non-OPEC oil production rises as production volumes increase, and the rising costs dampen further production growth.

Non-OPEC production of other liquids grows from 1.8 million barrels per day in 2011 to 4.6 million barrels per day in 2040, as Brent crude oil prices remain sufficiently high to make other liquids production technologies economically feasible. Non-OPEC liquids production in the Reference case totals 58 million barrels per day in 2020, 61 million barrels per day in 2030, and 64 million barrels per day in 2040.

### Low Oil Price case

The *AEO2013* Low Oil Price case assumes slower GDP growth for the non-OECD countries than in the Reference case. OPEC is less successful in restricting production in the Low Oil Price case, and as a result its share of total world liquids production increases to 49 percent in 2040. Despite lower Brent prices than in the Reference case, non-OPEC petroleum production levels are maintained at roughly 54 million barrels per day through 2030. After 2030, total non-OPEC production declines as existing fields are depleted and not fully replaced by production from new fields and more costly EOR technologies. With higher average costs for resource development in the non-OPEC countries, the Brent crude oil price in the Low Oil Price case is not sufficient to make all undeveloped fields economically viable. Non-OPEC petroleum production rises slightly in the projection, to 54 million barrels per day, before returning to roughly current levels of 51 million barrels per day in 2040. Non-OPEC production of other liquids grows more rapidly than in the Reference case, and in 2040 it is 25 percent higher than projected in the Reference case.

Brent crude oil prices fall below $80 per barrel in 2015 in the Low Oil Price case and decline further to just below $70 per barrel in 2017, followed by a slow increase to $75 per barrel in 2040. In the near term, extra supply enters the market, and lower economic growth in the non-OECD countries leads to falling prices. The higher levels of OPEC petroleum production assumed in the Low Oil Price case keep prices from increasing appreciably in the long term.

OPEC's ability to support higher oil prices is weakened by its inability to limit production as much as in the Reference case. Lower prices squeeze the revenues of OPEC members, increasing their incentive to produce beyond their quotas. As a result, OPEC liquids production increases to 54 million barrels per day in 2040. The lower prices in the Low Oil Price case cause a decline in OPEC revenue to the lowest level among the three cases, illustrating the relatively strong incentive for OPEC members to restrict supply.

### High Oil Price case

In the High Oil Price case, non-OECD GDP growth is more rapid than projected in the Reference case, and liquid fuels consumption per unit of GDP in the non-OECD countries declines more slowly than in the Reference case. Continuing restrictions on oil production keep the OPEC market share of total liquid fuels production between 37 and 40 percent, with total oil production about 1.0 million barrels per day lower than in the Reference case. Despite higher Brent oil prices, non-OPEC petroleum production initially expands at about the same rate as in the Reference case because of limited access to existing resources and lower discovery rates. Non-OPEC production of other liquids grows strongly in response to higher prices, rising to 8 million barrels per day in 2040.

Brent crude oil prices in the High Oil Price case increase to $155 per barrel in 2020 and $237 per barrel in 2040 in reaction to very high demand for liquid fuels in the non-OECD countries. The robust price increase keeps total world demand within the range of expected production capabilities.

## 3. U.S. reliance on imported liquid fuels in alternative scenarios

Liquid fuels [*71*] play a vital role in the U.S. energy system and economy, and access to affordable liquid fuels has contributed to the nation's economic prosperity. However, the extent of U.S. reliance on imported oil has often been raised as a matter of concern over the past 40 years. U.S. net imports of petroleum and other liquid fuels as a share of consumption have been one of the most-watched indicators in national and global energy analyses. After rising steadily from 1950 to 1977, when it reached 47 percent by the most comprehensive measure, U.S. net import dependence declined to 27 percent in 1985. Between 1985 and 2005, net imports of liquid fuels as a share of consumption again rose, reaching 60 percent in 2005. Since that time, however, the trend toward growing U.S. dependence on liquid fuels imports has again reversed, with the net import share falling to an estimated 41 percent in 2012, and with EIA projecting further significant declines in 2013 and 2014. The decline in net import dependence since 2005 has resulted from several disparate factors, and continued changes in those and other factors will determine how this indicator evolves in the future. Key questions include:

- What are the key determinants of U.S. liquid fuels supply and demand?
- Will the supply and demand trends that have reduced dependence on net imports since 2005 intensify or abate?
- What supply and demand developments could yield an outcome in which the United States is no longer a net importer of liquid fuels?

This discussion considers potential changes to the U.S. energy system that are inherently speculative and should be viewed as what-if cases. The four cases that are discussed include two cases (Low Oil and Gas Resources and High Oil and Gas Resources) in which only the supply assumptions are varied, and two cases (Low/No Net Imports and High Net Imports) in which both supply and demand assumptions change. The changes in these cases generate wide variation from the liquid fuels import dependence values seen in the *AEO2013* Reference case, but they should not be viewed as spanning the range of possible outcomes. Cases in which both supply and demand assumptions are modified show the greatest changes. In the Low/No Net Imports case, the United States ceases to be a net liquid fuels importer in the mid-2030s, and by 2040 U.S. net exports are 8 percent of total U.S. liquid fuel production. In contrast, in the High Net Imports case, net petroleum import dependence is above 44 percent in 2040, higher than the Reference case level of 37 percent but still well below the 60-percent level seen in 2005. Cases in which only supply assumptions are varied show intermediate levels of change in liquid fuels import dependence.

As the case names suggest, the Low Oil and Gas Resource case incorporates less-optimistic oil and natural gas resource assumptions than those in the Reference case, while the High Oil and Gas Resource case does the opposite. The other two cases combine different oil and natural gas resource assumptions with changes in assumptions that influence the demands for liquid fuels. The Low/No Net Imports case simulates an environment in which U.S. energy production grows rapidly while domestic consumption of liquid fuels declines. Conversely, the High Net Imports case combines the Low Oil and Gas Resource case assumptions with demand-related assumptions including slower improvements in vehicle efficiency, higher levels of vehicle miles traveled (VMT) relative to the Reference case, and reduced use of alternative transportation fuels.

## Resource assumptions

A key contributing factor to the recent decline in net import dependence has been the rapid growth of U.S. oil production from tight onshore formations, which has followed closely after the rapid growth of natural gas production from similar types of resources. Projections of future production trends inevitably reflect many uncertainties regarding the actual level of resources available, the difficulty in extracting them, and the evolution of the technologies (and associated costs) used to recover them. To represent these uncertainties, the assumptions used in the High and Low Oil and Gas Resource cases represent significant deviations from the Reference case.

Estimates of technically recoverable resources from the rapidly developing tight oil formations are particularly uncertain and change over time as new information is gained through drilling, production, and technology experimentation. Over the past decade, as more tight and shale formations have gone into commercial production, estimates of technically and economically recoverable resources have generally increased. Technically recoverable resource estimates, however, embody many assumptions that might not prove to be true over the long term, over the entire range of tight or shale formations, or even within particular formations. For example, the tight oil resource estimates in the Reference case assume that production rates achieved in a limited portion of a given formation are representative of the entire formation, even though neighboring tight oil well production rates can vary widely. Any specific tight or shale formation can vary significantly across the formation with respect to relevant characteristics [*72*], resulting in widely varying rates of well production. The application of refinements to current technologies, as well as new technological advancements, can also have a significant but highly uncertain impact on the recoverability of tight and shale crude oil.

As shown in Table 5, the High and Low Oil and Gas Resource cases were developed with alternative crude oil and natural gas resource assumptions giving higher and lower technically recoverable resources than assumed in the Reference case. While these cases do not represent upper and lower bounds on future domestic oil and natural gas supply, they allow for an examination of the potential effects of higher and lower domestic supply on energy demand, imports, and prices.

The Low Oil and Gas Resource case only reflects the uncertainty around tight oil and shale gas resources. The resource estimates in the Reference case are based on crude oil and natural gas production rates achieved in a limited portion of the tight or shale formation and are assumed to be representative of the entire formation. However, the variability in formation characteristics described earlier can also affect the estimated ultimate recovery (EUR) of wells. For the Low Oil and Gas Resource case, the EUR per tight and shale well is assumed to be 50 percent lower than in the *AEO2013* Reference case. All other resource assumptions are unchanged from the Reference case.

The High Oil and Gas Resource case reflects a broad-based increase in crude oil and natural gas resources. Optimism regarding increased supply has been buoyed by recent advances in crude oil and natural gas production that resulted in an unprecedented annual increase in U.S. crude oil production in 2012. The *AEO2013* Reference case shows continued near-term production growth followed by a decline in U.S. production after 2020. The High Oil and Gas Resource case presents a scenario in which U.S. crude oil production continues to expand after about 2020 due to assumed higher technically recoverable tight oil resources, as well as undiscovered resources in Alaska and the offshore Lower 48 states. In addition, the maximum annual penetration rate for GTL technology is doubled compared to the Reference case.

The tight and shale resources are increased by changing both the EUR per well and the well spacing. A doubling in tight and shale well EUR, when assumed to occur through raising the production type curves [73] across the board, is responsible for the significantly faster increases in production and is also a contributing factor in avoiding the production decline during the projection period. This assumption change is quite optimistic and may alternatively be considered as a proxy for other changes or combinations of changes that have yet to be observed.

Although initial production rates have increased over the past few years, it is too early to conclude that overall EURs have increased and will continue to increase. Instead, producers may just be recovering the resource more quickly, resulting in a more dramatic decline in production later, with little impact on the well's overall EUR. The decreased well spacing reflects less the capability to drill wells closer together (i.e., avoid interference) and instead more the discovery of and production from other shale plays that are not yet in commercial development. These may either be stacked in the same formation or reflect future technological innovations that would bring into production plays that are otherwise not amenable to current hydraulic fracturing technology.

Other resources also are assumed to contribute to supply, as technological or other unforeseen changes improve their prospects. The resource assumptions for the offshore Lower 48 states in the High Oil and Gas Resource case reflect the possibility that resources may be substantially higher than assumed in the Reference case. Resource estimates for most of the U.S. Outer Continental Shelf are uncertain, particularly for resources in undeveloped regions where there has been little or no exploration and development activity, and where modern seismic survey data are lacking [74]. The increase in crude oil resources in Alaska reflects the possibility that there may be more crude oil on the North Slope, including tight oil. It does not, however, reflect an opening of the Arctic National Wildlife Refuge to exploration or production activity. Finally, modest production from kerogen (oil shale) resources, which remains below 140,000 barrels per day through the 2040 projection horizon, is included in the High Oil and Gas Resource case.

### Table 5. Differences in crude oil and natural gas assumptions across three cases

| | Reference | | | |
|---|---|---|---|---|
| Resource | Average | Range | Low Oil and Gas Resource | High Oil and Gas Resource |
| Shale gas, tight gas, and tight oil | | | | |
| Estimated Ultimate Recovery | | | | |
| Shale gas (billion cubic feet per well) | 1.04 | 0.01-11.32 | 50% lower | 100% higher |
| Tight gas (billion cubic feet per well) | 0.5 | 0.01-11.02 | 50% lower | 100% higher |
| Tight oil (thousand barrels per well) | 135 | 1-778 | 50% lower | 100% higher |
| Incremental technically recoverable resource | | | | |
| Natural gas (trillion cubic feet) | -- | -- | (522) | 1,044 |
| Crude oil (billion barrels) | -- | -- | (29) | 58 |
| Well spacing (acres) | 100 | 20-406 | No change | 20-40 |
| Incremental technically recoverable resource | | | | |
| Natural gas (trillion cubic feet) | -- | -- | No change | 3,601 |
| Crude oil (billion barrels) | -- | -- | No change | 269 |
| Alaska | | | | |
| North Slope onshore & offshore | | | | |
| Offshore production start year | 2029 | | No change | 2025 |
| Undiscovered crude oil (billion barrels) | 22 | | No change | 50% higher |
| Incremental technically recoverable resource (billion barrels) | -- | | No change | 11 |
| Tight oil technically recoverable resource (billion barrels) | None | | No change | 1.9 |
| Lower 48 states | | | | |
| Offshore undiscovered resources | | | | |
| Crude oil (billion barrels) | 40 | | No change | 50% higher |
| Natural gas (trillion cubic feet) | 208 | | No change | 50% higher |
| Incremental technically recoverable resource | | | | |
| Natural gas (trillion cubic feet) | -- | | No change | 104 |
| Crude oil (billion barrels) | -- | | No change | 20 |
| Kerogen (oil shale) | | | | |
| Technically recoverable resource | -- | | No change | No change |
| 2040 production (thousand barrels per day) | None | | None | 135 |

## Demand assumptions

Reductions in demand for liquid fuels in some uses, such as personal transportation and home heating, coupled with slow growth in other applications, have been another key contributing factor in the decline of the nation's net dependence on imported liquid fuels since 2005. As with supply assumptions, the key analytic assumptions that drive future trends in liquid fuels demand in EIA's projections are subject to considerable uncertainty. The most important assumptions affecting future demand for liquids fuels include:

- The future level of activities that use liquid fuels, such as VMT
- The future efficiency of equipment that uses liquid fuels, such as automobiles, trucks, and aircraft
- The future extent of fuel switching that replaces liquid fuels with other fuel types, such as liquefied natural gas (LNG), biofuels, or electricity.

Two alternative sets of demand assumptions that lead to higher or lower demand for liquid fuels than in the *AEO2013* Reference case are outlined below. The two alternative scenarios are then applied in conjunction with the High and Low Oil and Gas Resource cases to develop the Low/No Net Import and High Net Import cases.

### Vehicle miles traveled

Projected fuel use by LDVs is directly proportional to light-duty VMT, which can be influenced by policy, but it is driven primarily by market factors, demography, and consumer preferences. All else being equal, VMT is more likely to grow when the driving-age population is growing, economic activity is robust, and fuel prices are moderate. For example, there is a strong linkage between economic activity, employment, and commuting. In addition, there is a correlation between income and discretionary travel that reinforces the economy-VMT link. Turning to demography, factors such as the population level, age distribution, and household composition are perhaps most important for VMT. For example, lower immigration would lead to a smaller U.S. population over time, lowering VMT. The aging of the U.S. population continues and will also have long-term effects on VMT trends, as older drivers do not behave in the same ways as younger or middle-aged drivers. At times, the factors that influence VMT intertwine in ways that change long-term trends in U.S. driving and fuel consumption. For example, the increase in two-income families that occurred beginning in the 1970s created a surge in VMT that involved both economic activity and demographics.

Alternative modes of travel affect VMT to the degree that the population substitutes other travel services for personal LDVs. The level of change is related to the cost, convenience, and geographic extent of mass transit, rail, biking, and pedestrian travel service options. Car-sharing services, which have grown in popularity in recent years, could discourage personal vehicle VMT by putting more of the cost of incremental vehicle use on the margin when compared with traditional vehicle ownership or leasing, where many of the major costs of vehicle use are incurred at the time a vehicle is acquired, registered, and insured. Improvements in the fuel efficiency of vehicles, however, could increase VMT by lowering the marginal costs of driving. In recent analyses supporting the promulgation of new final fuel economy and GHG standards for LDVs in MY 2017 through 2025, NHTSA and EPA applied a 10-percent rebound in travel to reflect the lower fueling costs of more efficient vehicles [*75*]. Both higher and lower values for the rebound have been advanced by various analysts [*76*].

Other types of technological change also can affect projected VMT growth. E-commerce, telework, and social media can supplant (or complement) personal vehicle use. Some analysts have suggested an association between rising interest in social media and a decline in the rates at which driving-age youth secure driver licenses; however, that decline also could be related to recent weakness in the economy.

Many of the factors reviewed above were also addressed in the August 2012 National Petroleum Council Future Transportation Fuels study [*77*]. That study considered numerous specific research efforts, as well as available summaries of the literature on VMT, and concluded that the economic and demographic factors remain dominant. The VMT scenario adopted for most of the analysis in that study reflected declining compound annual growth rates of VMT over time, with the growth rate in VMT, which was 3.1 percent in the 1971-1995 and 2.0 percent in the 1996-2007 periods, falling to under 1 percent after 2035.

In the *AEO2013* Reference case, the compound annual rate of growth in light-duty VMT over the period from 2011 to 2040 is 1.2 percent—well below the historical record through 2005 but significantly higher than the average annual light-duty VMT growth rate of 0.7 percent from 2005 through 2011. The 2005-2011 period was marked by generally poor economic performance, high unemployment, and high liquid fuel prices, all of which likely contributed to lower VMT growth. While VMT growth rates are expected to rise as the economy and employment levels improve, it remains to be seen to what extent such effects might be counteracted or reinforced by some of the other market factors identified above.

The low demand scenario used in the Low/No Net Imports case holds the growth rate of light-duty VMT over the 2011-2040 period at 0.2 percent per year, lower than its 2005-2011 growth rate. The application of a lower growth rate over a 29-year projection period results in total light-duty VMT 26 percent below the Reference case level in 2040. With population growth at 0.9 percent per year, this implies a decline of 0.7 percent per year in VMT per capita. VMT per licensed driver, which increases by 0.3 percent per year in the *AEO2013* Reference case, declines at a rate of 0.8 percent per year in the Low/No Net Imports case. In the High Net Imports case, which assumes more robust demand than in the Reference case, the VMT projection remains close to that in the Reference case, with higher demand resulting from other factors.

**Vehicle efficiencies**

Turning to vehicle efficiency, the rising fuel economy of new LDVs already has contributed to recent trends in liquid fuels use. Looking forward, the EPA and NHTSA have established joint CAFE and GHG emissions standards through MY 2025. The new CAFE standards result in a fuel economy, measured as a program compliance value, of 47.3 mpg for new LDVs in 2025, based on the distribution of production of passenger cars and light trucks by footprint in *AEO2013*. The EPA and NHTSA also have established a fuel efficiency and GHG emissions program for medium- and heavy-duty vehicles for MY 2014-18. The fuel consumption standards for MY 2014-15 set by NHTSA are voluntary, while the standards for MY 2016 and beyond are mandatory, except those for diesel engines, which are mandatory starting in 2017.

The *AEO2013* Reference case does not consider any possible reduction in fuel economy standards resulting from the scheduled midterm review of the CAFE standards for MY 2023-25, or for any increase in fuel economy standards that may be put in place for model years beyond 2025. The low demand scenario in this article adopts the assumption that post-2025 LDV CAFE standards increase at an average annual rate of 1.4 percent, the same assumption made in the *AEO2013* Extended Policies case. In contrast, the high demand scenario assumes some reduction in current CAFE standards following the scheduled midterm review.

**Fuel switching**

In the *AEO2013* Reference case, fuel switching to natural gas in the form of compressed natural gas (CNG) and LNG already is projected to achieve significant penetration of natural gas as a fuel for heavy-duty trucks. In the Reference case, natural gas use in heavy-duty vehicles increases to 1 trillion cubic feet per year in 2040, displacing 0.5 million barrels per day of diesel use. The use of natural gas in the Reference case is economically driven. Even after the substantial costs of liquefaction or compression, fuel costs for LNG or CNG are expected to be well below the projected cost of diesel fuel on an energy-equivalent basis. The fuel cost advantage is expected to be large enough in the view of a significant number of operators to offset the considerably higher acquisition costs of vehicles equipped to use these fuels, in addition to offsetting other disadvantages, such as reduced maximum range without refueling, a lower number of refueling locations, reduced volume capacity in certain applications, and an uncertain resale market for vehicles using alternative fuels. For purposes of the low demand scenario for liquid fuels, factors limiting the use of natural gas in heavy-duty vehicles are assumed to be less significant, allowing for higher rates of market penetration.

Natural gas could also prove to be an attractive fuel in other transportation applications. The use of LNG as a fuel for rail transport, which had earlier been considered for environmental reasons, is now under active consideration by major U.S. railroads for economic reasons, motivated by the same gap between the cost of diesel fuel and LNG now and over the projection period. Because all modern railroad locomotives use electric motors to drive their wheels, a switch from diesel to LNG would entail the use of a different fuel to drive the onboard electric generation system. Retrofits have been demonstrated, but new locomotives with generating units specifically optimized for LNG could prove to be more attractive. Because railroads already maintain their own on-system refueling infrastructure, they may be less subject to the concern that truckers considering a switch to alternative fuel vehicles might have regarding the risks that natural gas refueling systems they require would not actually be built. The high concentration of ownership in the U.S. railroad industry could also facilitate a rapid switch toward LNG refueling, with the associated transition to new equipment, under the right circumstances because there are only a few owners making the decisions.

Marine operators have traditionally relied on oil-based fuels, with large oceangoing vessels almost exclusively fueled with heavy high-sulfur fuel oil that typically sells at a discount relative to other petroleum products. Under the International Maritime Organization's International Convention on the Prevention of Pollution from Ships agreement (MARPOL Annex VI) [*78*], the use of heavy high-sulfur fuel oil in international shipping started being phased out for environmental reasons in 2010. Although LNG is one possible option, there are many cost and logistical challenges, including the high cost of retrofits, the long lifetime of existing vessels, and relatively low utilization rates for many routes that will have adverse impacts on the economics of marine LNG refueling infrastructure. Unlike the heavy-duty truck market, there has not yet been an LNG-fueled product offered for general use by manufacturers of marine or rail equipment, making cost and performance comparisons inherently speculative.

In addition to the demand assumptions discussed above, other assumption changes were made to capture potential shifts in vehicle cost and consumer preference for LDVs powered by alternative fuels. In the Low/No Net Imports case, the costs of efficiency technologies and battery technologies were lowered, and the market penetration of E85 fuel was increased, relative to the Reference case levels. With regard to E85, assumptions about consumer preference for flex-fuel vehicles were altered to allow for increases in vehicle sales and E85 demand, leading to greater use of domestically-produced biofuel than projected in the Reference case.

Table 6 summarizes the demand-side assumptions in the alternative demand scenarios for liquid fuels. As with the supply assumptions, the assumptions used in the higher and lower demand cases represent substantial deviations from the *AEO2013* Reference case, and they might instead be realized in terms of other, as-yet-unforeseen developments in technology, economics, or policy.

## Results

The cases considered show how the future share of net imports in total U.S. liquid fuel use varies with changes in assumptions about the key factors that drive domestic supply and demand for liquid fuels (Figure 24). Some of the assumptions in the Low/No Net imports case, such as assumed increases in LDV fuel economy after 2025 and access to offshore resources, could be influenced by future energy policies. However, other assumptions in this case, such as the greater availability of onshore technically recoverable oil and natural gas resources, depend on geological outcomes that cannot be influenced by policy measures; and economic, consumer, or technological factors may likewise be unaffected or only slightly affected by policy measures.

### Net imports and prices

In the Low/No Net Imports case, U.S. net imports of liquid fuels are eliminated in the mid-2030s, and the United States becomes a modest net exporter of those fuels by 2040. As discussed above, this case combines optimistic assumptions about the availability of domestic oil and natural gas resources with assumptions that lower demand for liquid fuels, including a decline in VMT per capita, increased switching to natural gas fuels for transportation (including heavy-duty trucks, rail, boats, and ships), continued significant improvements in the fuel efficiency of new vehicles beyond 2025, wider availability and lower costs of electric battery technologies, and greater market penetration of biofuels and other nonpetroleum liquids. Although other combinations of assumptions, or unforeseen technology breakthroughs, might produce a comparable outcome, the assumptions in the Low/No Net Imports case illustrate the magnitude and type of changes that would be required for the United States to end its reliance on net imports of liquid fuels, which began in 1946 and has continued to the present day. Moreover, regardless of how much the United States is able to reduce its reliance on imported liquids, it will not be entirely insulated from price shocks that affect the global oil market [79].

As shown in Figure 24, the supply assumptions of the High Oil and Gas Resource case alone result in a decline in net import dependence to 7 percent in 2040, compared to 37 percent in the Reference case, with U.S. crude oil production rising to 10.2 million barrels per day in 2040, or 4.1 million barrels per day above the Reference case level. Tight oil production accounts for more than 77 percent (or 3 million barrels per day) of the difference in production between the two cases. Production of NGL in the United States also exceeds the Reference case level.

**Figure 24. Net import share of liquid fuels in five cases, 2005-2040 (percent)**

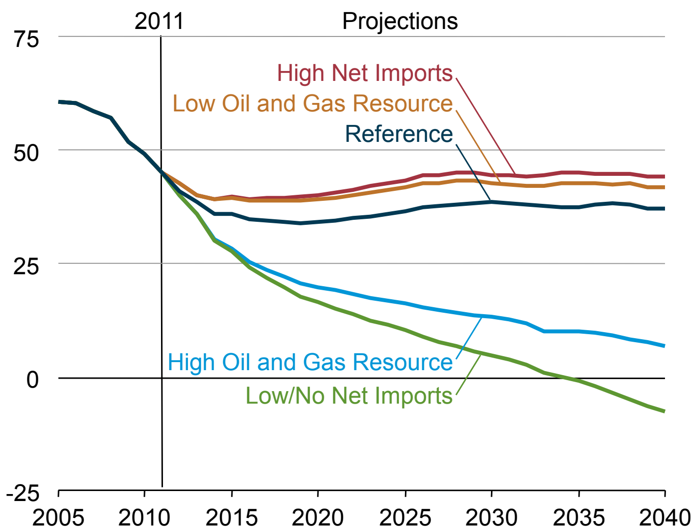



**Table 6. Differences in transportation demand assumptions across three cases**

| Transportation mode | Reference | Low/No Net Imports | High Net Imports |
|---|---|---|---|
| Light-duty vehicles | | | |
| Vehicle miles traveled (compound annual growth rate, 2011-2040) | 1.2% | 0.2% | 1.1% |
| Vehicle technology efficiency in 2040 | Baseline | Baseline + 10% | Baseline - 10% |
| Vehicle technology cost in 2040 | Baseline | Baseline - 10% | Baseline + 10% |
| CAFE standard compliance value in 2040 (miles per gallon) | 49.0 | 57.7 | 39.9 |
| Flex-fuel vehicle stock in 2040 (millions) | 20.9 | 44.3 | 20.0 |
| Battery-electric vehicle costs | Baseline | Baseline - 14% | Baseline |
| Heavy-duty vehicles | | | |
| Vehicle technology efficiency in 2040 | Baseline | Baseline + 10% | Baseline - 10% |
| Vehicle technology cost in 2040 | Baseline | Baseline - 10% | Baseline + 10% |
| Potential market share for natural gas fuel | 27% | 41% | 27% |
| Marine | | | |
| Efficiency (ton-miles per thousand Btu) | 2.55 | 2.66 | 2.41 |
| Potential market share for natural gas fuel | 0% | 8% | 0% |
| Rail | | | |
| Efficiency (ton-miles per thousand Btu) | 3.54 | 3.70 | 3.44 |
| Potential market share for natural gas fuel | 0% | 100% | 0% |

As a result of higher U.S. liquid fuels production, Brent crude oil prices in the High Oil and Gas Resource case are lower than in the Reference case, which also lowers motor gasoline and diesel prices to the transportation sector, encouraging greater consumption and partially dampening the projected decline in net dependence on liquid fuel imports. In the High Oil and Gas Resource case, the reduction in motor fuels prices increases fuel consumption in 2040 by 350 thousand barrels per day in the transportation sector and 230 thousand barrels per day in the industrial sector, which accounts for nearly all of the increase in total U.S. liquid fuels consumption (600 thousand barrels per day) relative to the Reference case total in 2040.

**Global market, the economy, and refining**

The addition of assumptions that slow the growth of demand for liquid fuels in the Low/No Net Imports case more than offsets the increase in demand that results from lower liquid fuel prices, so that total liquid fuels consumption in 2040 is 2.1 million barrels per day lower than projected in the Reference case. The combination of high crude oil and natural gas resources and lower demand for liquid fuels pushes Brent crude oil prices to $29 per barrel below the Reference case level in 2040. However, given the cumulative impact of factors that tend to raise world oil prices in real terms over the projection period, inflation-adjusted crude oil prices in the Low/No Net Imports case are still above today's price level.

One of the most uncertain aspects of the analysis concerns the effect on the global market for liquid fuels, which is highly integrated. Although the analysis reflects price effects that are based on the relative scale of the changes in U.S. domestic supply and net U.S. imports of liquid fuels within the overall international crude oil market, strategic choices made by the leading oil-exporting countries could result in price and quantity effects that differ significantly from those presented here. Moreover, regardless of how much the United States reduces its reliance on imported liquids, consumer prices will not be insulated from global oil prices if current policies and regulations remain in effect and world markets for crude oil streams of sulfur quality remain closely aligned absent transportation bottlenecks [*80*].

Although the focus is mainly on liquid fuels markets, the more optimistic resource assumptions in the High Oil and Gas Resource case also lead to more natural gas production. The higher productivity of shale and tight gas wells puts downward pressure on natural gas prices and thus encourages increased domestic consumption of natural gas (38 trillion cubic feet in the High Oil and Gas Resource case, compared to 30 trillion cubic feet in the Reference case in 2040) and higher net exports (both pipeline and LNG) of natural gas. As a result, projected domestic natural gas production in 2040 is considerably higher in the High Oil and Gas Resource case (45 trillion cubic feet) than in the Reference case (33 trillion cubic feet).

The Low Oil and Gas Resource case illustrates the implications of an outcome in which U.S. oil and gas resources turn out to be smaller than expected in the Reference case. In this case, domestic crude oil production peaks in 2016 at 6.9 million barrels per day, declines to 5.9 million barrels per day in 2028, and remains relatively flat (between 5.8 and 6.0 million barrels per day) through 2040. The lower well productivity in this case puts upward pressure on natural gas prices, resulting in lower natural gas consumption and production. In 2040, U.S. natural gas production is 27 trillion cubic feet in the Low Oil and Gas Resource case, compared with 33 trillion cubic feet in the Reference case.

These alternative cases may also have significant implications for the broader economy. Liquid fuels provide power and raw materials (feedstocks) for a substantial portion of the U.S. economy, and the macroeconomic impacts of both the High Oil and Gas Resource case and the Low/No Net Imports case suggest that significant economic benefits would accrue if some version of those futures were realized (see discussion of NGL later in "Issues in focus"). This is in spite of the fact that petroleum remains a global market in each of the scenarios, which limits the price impacts for gasoline, diesel, and other petroleum-derived fuels. In the High Oil and Gas Resource case, increasing energy production has immediate benefits for the economy. U.S. industries produce more goods with 12 percent lower energy costs in 2025 and 15 percent lower energy costs in 2040. Consumers see roughly 10 percent lower energy prices in 2025, and 13 percent lower energy prices in 2040, as compared with the Reference case. Cheaper energy allows the economy to expand further, with real GDP attaining levels that are on average about 1 percent above those in the Reference case from 2025 through 2040, including growth in both aggregate consumption and investment.

The alternative cases also imply substantial changes in the future operations of U.S. petroleum refineries, as is particularly evident in the Low/No Net Imports case. Drastically reduced product consumption and increased nonpetroleum sources of transportation fuels, taken in isolation, would tend to reduce utilization of U.S. refineries. The combination of higher domestic crude supply and reduced crude runs in the refining sector would sharply reduce or eliminate crude oil imports and could potentially create market pressure for crude oil exports to balance crude supply with refinery runs. However, under current laws and regulations, crude exports require licenses that have not been issued except in circumstances involving exports to Canada or exports of limited quantities of specific crude streams, such as California heavy oil [*81*].

Rather than assuming a change in current policies toward crude oil exports, and recognizing the high efficiency and low operating costs of U.S. refineries relative to global competitors in the refining sector, exports of petroleum products, which are not subject to export licensing requirements, rise significantly to avoid the uneconomical unloading of efficient U.S. refinery capacity, continuing a trend that has already become evident over the past several years. Product exports rise until the incremental refining value of crude oil processed is equivalent to the cost of crude imports. To balance the rest of the world as a result of increased U.S. product exports, it is assumed that the increased volumes of U.S. liquid fuel product exports would result in a decrease in the volume of the rest of the world's crude runs, and that world consumption, net of U.S. exports, would also be reduced by an amount necessary to keep demand and supply volumes in balance.

**Projected carbon dioxide emissions**

Total U.S. $CO_2$ emissions show the impacts of changing fuel prices through all the sectors of the economy. In the High Oil and Gas Resource case, the availability of more natural gas at lower prices encourages the electric power sector to increase its reliance on natural gas for electricity generation. Coal is the most affected, with coal displaced over the first part of the projection, and new renewable generation sources also affected after 2030 or so, resulting in projected $CO_2$ emissions in the High Oil and Gas Resource case that exceed those in the Reference case after 2035 (Figure 25). With less-plentiful and more-expensive natural gas in the Low Oil and Gas Resource and High Net Imports cases, the reverse is true, with fewer coal retirements leading to higher $CO_2$ emissions than in the Reference case early in the projection period. Later in the projection, however, the electric power sector turns first to renewable technologies earlier in the Low Oil and Gas Resource and High Net Imports cases, and after 2030 invests in more nuclear plants, reducing $CO_2$ emissions from the levels projected in the Reference case. In the Low Oil and Gas Resource case, $CO_2$ emissions are lower than in the Reference case starting in 2026. In the Low/No Net Imports case, annual $CO_2$ emissions from the transportation sector continue to decline as a result of reduced travel demand; these emissions are conversely higher in the High Net Imports case. Figure 25 summarizes the $CO_2$ emissions projections in the cases completed for this analysis.

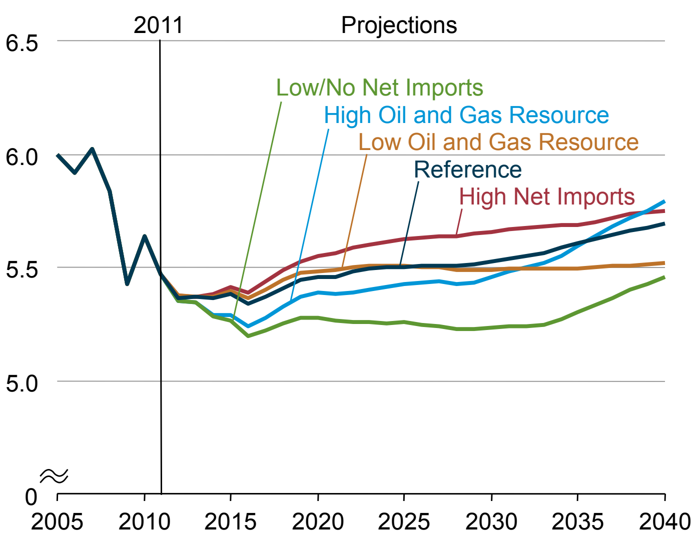
## 4. Competition between coal and natural gas in the electric power sector

Over the past 20 years, natural gas has been the go-to fuel for new electricity generation capacity. From 1990 to 2011, natural gas-fired plants accounted for 77 percent of all generating capacity additions, and many of the plants added were very efficient combined-cycle plants. However, with slow growth in electricity demand and spikes in natural gas prices between 2005 and 2008, much of the added capacity was used infrequently. Since 2009 natural gas prices have been relatively low, making efficient natural gas-fired combined-cycle plants increasingly competitive to operate in comparison with existing coal-fired plants, particularly in the Southeast and other regions where they have been used to meet demand formerly served by coal-fired plants. In 2012, as natural gas prices reached historic lows, there were many months when natural gas displacement of coal-fired generation was widespread nationally.

In the *AEO2013* Reference case, the competition between coal and natural gas in electricity generation is expected to continue in the near term, particularly in certain regions. However, because natural gas prices are projected to increase more rapidly than coal prices, existing coal plants gradually recapture some of the market lost in recent years. Natural gas-fired plants continue to be the favored source for new generating capacity over much of the projection period because of their relatively low costs and high efficiencies. The natural gas share of total electricity generation increases in the Reference case from 24 percent in 2011 to 30 percent in 2040. Coal remains the largest source of electricity generation, but its share of total electricity generation, which was 51 percent in 2003, declines from 42 percent in 2011 to 35 percent in 2040.

At any point, short-term competition between existing coal- and gas-fired generators—i.e., the decisions determining which generators will be dispatched to generate electricity—depends largely on the relative operating costs for each type of generation, of which fuel costs are a major portion. A second aspect of competition occurs over the longer term, as developers choose which fuels and technologies to use for new capacity builds and whether or not to make mandated or optional upgrades to existing plants. The natural gas or coal share of total generation depends both on the available capacity of each fuel type (affected by the latter type of competition) and on how intensively the capacity is operated.

**Figure 25. U.S. carbon dioxide emissions in five cases, 2005-2040 (billion metric tons)**




There is significant uncertainty about future coal and natural gas prices, as well as about future growth in electricity demand, which determines the need for new generating capacity. In *AEO2013*, alternative cases with higher and lower coal and natural gas prices and variations in the rate of electricity demand growth are used to examine the potential impacts of those uncertainties. The alternative cases illustrate the influence of fuel prices and demand on dispatch and capacity planning decisions.

### Recent history of price-based competition

In recent years, natural gas has come into dispatch-level competition with coal as the cost of operating natural gas-fired generators has neared the cost of operating coal-fired generators. A number of factors led to the growing competition, including:

- A build-out of efficient combined-cycle capacity during the early 2000s, which in general was used infrequently until recently

- Expansion of the natural gas pipeline network, reducing uncertainty about the availability of natural gas
- Gains in natural gas production from domestic shale formations that have contributed to falling natural gas prices
- Rising coal prices.

Until mid-2008, coal-fired generators were cheaper to operate than natural gas-fired generators in most applications and regions. Competition between available natural gas combined-cycle generators (NGCC) and generators burning eastern (Appalachian) and imported coal began in southeastern electric markets in 2009. Rough parity between NGCC and more expensive coal-fired plants continued until late 2011, when increased natural gas production led to a decline in the fuel price and, in the spring of 2012, a dramatic increase in competition between natural gas and even less expensive types of coal. With natural gas-fired generation increasing steadily, the natural gas share of U.S. electric power sector electricity generation was almost equal to the coal share for the first time in April 2012.

The following discussion focuses on the electric power sector, excluding other generation sources in the residential, commercial, and industrial end-use sectors. The industrial sector in particular may also respond to changes in coal and natural gas fuel prices by varying their level of development, but industrial users typically do not have the option to choose between the fuels as in the power sector, and there are fewer opportunities for direct competition between coal and natural gas for electricity generation.

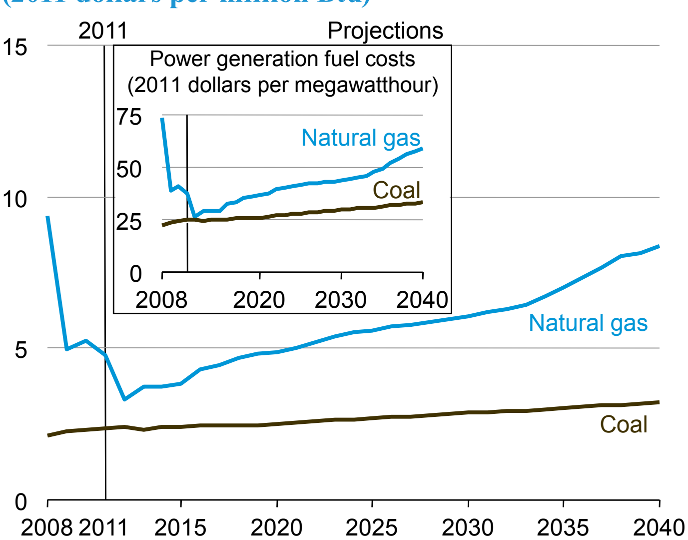
### Outlook for fuel competition in power generation

The difference between average annual prices per million Btu for natural gas and coal delivered to U.S. electric power plants narrowed substantially in 2012, so that the fuel costs of generating power from NGCC units and coal steam turbines per megawatthour were essentially equal on a national average basis (Figure 26), given that combined-cycle plants are much more efficient than coal-fired plants. When the ratio of natural gas prices to coal prices is approximately 1.5 or lower, a typical natural gas-fired combined-cycle plant has lower generating costs than a typical coal-fired plant. In the Reference case projection, natural gas plants begin to lose competitive advantage over time, as natural gas prices increase relative to coal prices. Because fuel prices vary by region, and because there is also considerable variation in efficiencies across the existing fleet of both coal-fired and combined-cycle plants, dispatch-level competition between coal and natural gas continues.

In the Reference case, coal-fired generation increases from 2012 levels and recaptures some of the power generation market lost to natural gas in recent years. The extent of that recovery varies significantly, however, depending on assumptions about the relative prices of the two fuels. The following alternative cases, which assume higher or lower availability or prices for natural gas and coal than in the Reference case are used to examine the likely effects of different market conditions:

- The Low Oil and Gas Resource case assumes that the EUR per shale gas, tight gas, or tight oil well is 50 percent lower than in the Reference Case. In 2040, delivered natural gas prices to the electric power sector are 26 percent higher than in the Reference case.
- The High Oil and Gas Resource case assumes that the EUR per shale gas, tight gas, or tight oil well is 100 percent higher than in the Reference case, and the maximum well spacing for shale gas, tight gas, and tight oil plays is assumed to be 40 acres. This case also assumes that the EUR for wells in the Alaska offshore and the Federal Gulf of Mexico is 50 percent higher than in the Reference case, that there is development of kerogen resources in the lower 48 states, and that the schedule for development of Alaskan resources is accelerated. In 2040, delivered natural gas prices are 39 percent lower than projected in the Reference case.

**Figure 26. Average delivered fuel prices to electric power plants in the Reference case, 2008-2040 (2011 dollars per million Btu)**




- The High Coal Cost case assumes lower mine productivity and higher costs for labor, mine equipment, and coal transportation, which ultimately result in higher coal prices for electric power plants. In 2040, the delivered coal price is 77 percent higher than in the Reference case.
- The Low Coal Cost case assumes higher mining productivity and lower costs for labor, mine equipment, and coal transportation, leading to lower coal prices for electric power plants. In 2040, the delivered coal price is 41 percent lower than in the Reference case.

Figure 27 compares the ratio of average per-megawatthour fuel costs for NGCC plants and coal steam turbines at the national level across the cases. It illustrates the relative competitiveness of dispatching coal-fired steam turbines versus NGCC plants, including the differences in efficiency (heat rates) of the two types of generators. The ratio of natural gas to coal would be about 1.5 without considering the difference in efficiency. Higher coal prices or lower natural gas prices move the ratio closer to the line of competitive parity, where NGCC plants have more opportunities to displace coal-fired generators. In contrast, when coal prices are much lower than in the Reference case, or natural gas prices are much higher, the ratio is higher, indicating less likelihood of dispatch-level competition between coal and natural gas. In both the High Oil and Gas Resource case and the High Coal Cost case, the average NGCC plant is close to parity with, or more economical than, the average coal-fired steam turbine.

**Capacity by plant type**

In all five cases, coal-fired generating capacity in 2025 (Figure 28) is below the 2011 total and remains lower through 2040 (Figure 29), as retirements outpace new additions of coal-fired capacity. Coal and natural gas prices are key factors in the decision to retire a power plant, along with environmental regulations and the demand for electricity. In the Low Oil and Gas Resource case and Low Coal Cost case, there are slightly fewer retirements than in the Reference case, as a higher fuel cost ratio for power generation is more favorable to coal-fired power plants. In the High Oil and Gas Resource case and High Coal Cost case, coal-fired plants are used less, and more coal-fired capacity is retired than in the Reference case. In the Reference case, 49 gigawatts of coal-fired capacity is retired from 2011 to 2040, compared with a range from 38 gigawatts to 73 gigawatts in the alternative cases. The interaction of fuel prices and environmental rules is a key factor in coal plant retirements. *AEO2013* assumes that all coal-fired plants have flue gas desulfurization equipment (scrubbers) or dry sorbent injection systems installed by 2016 to comply with the Mercury and Air Toxics Standards. Higher coal prices, lower wholesale electricity prices (often tied to natural gas prices), and reduced use may make investment in such equipment uneconomical in some cases, resulting in plant retirements.

In all the cases examined, new additions of coal-fired capacity from 2012 to 2040 total less than 15 gigawatts. For new builds, natural gas and renewables generally are more competitive than coal, and concerns surrounding potential future GHG legislation also dampen interest in new coal-fired capacity [*82*]. New capacity additions are not the most important factor in the competition between coal and natural gas for electricity generation. There is also significant dispatch-level competition in determining how intensively to operate existing coal-fired power plants versus new and existing natural gas-fired plants.

New natural gas-fired capacity, including combined-cycle units and combustion turbines, comprises the majority of new additions in the Reference case. The total capacity of all U.S. natural gas-fired power plants grows in each of the cases, but the levels vary depending on the relative fuel prices projected. Across the resource cases, NGCC capacity in 2025 ranges between 227 and 243 gigawatts, and in 2040 it ranges between 262 and 344 gigawatts, reflecting the impacts of fuel prices on the operating costs of new capacity.

**Figure 27. Ratio of average per megawatthour fuel costs for natural gas combined-cycle plants to coal-fired steam turbines in five cases, 2008-2040**

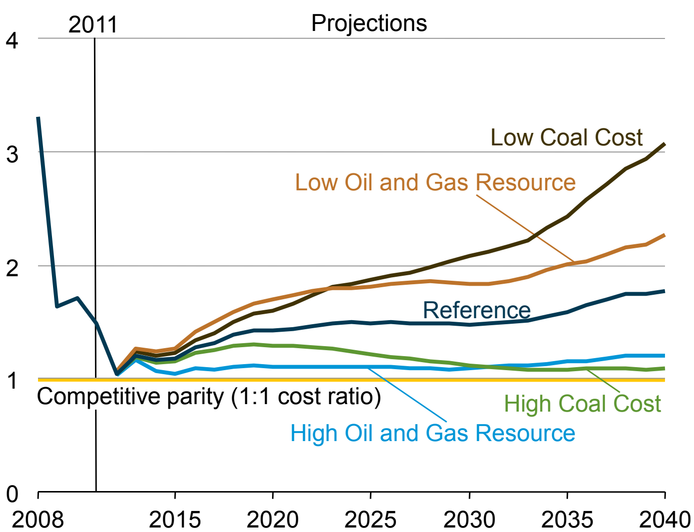



**Figure 28. Power sector electricity generation capacity by fuel in five cases, 2011 and 2025 (gigawatts)**

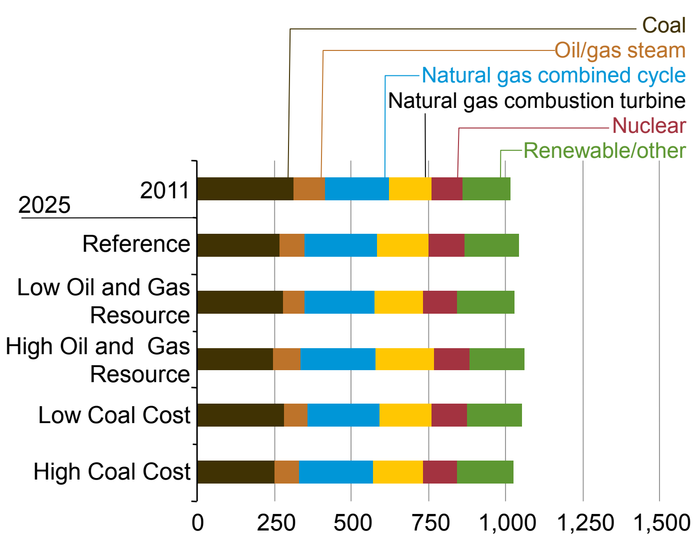
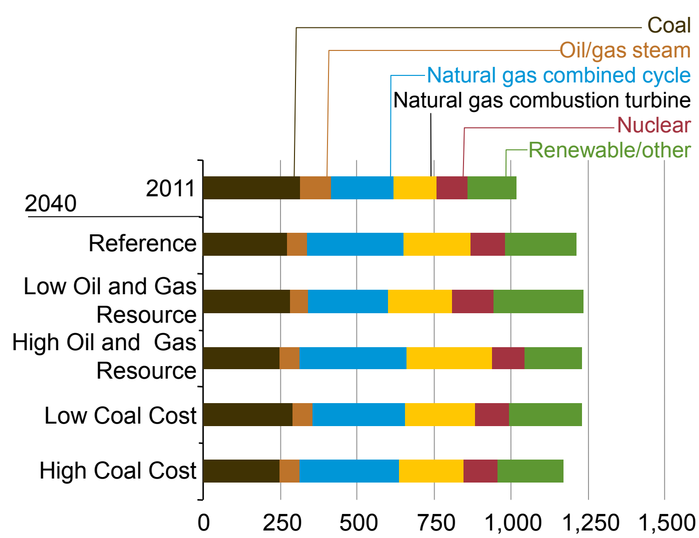



**Figure 29. Power sector electricity generation capacity by fuel in five cases, 2011 and 2040 (gigawatts)**



New nuclear capacity and renewable capacity are affected primarily by changes in natural gas prices, with substantial growth in both technologies occurring in the Low Oil and Gas Resource case. Most of the increase occurs after 2025, when delivered natural gas prices in that case exceed $7 per million Btu, and the costs of the nuclear and renewable technologies have fallen from current levels. In this case, higher natural gas prices reduce the competitiveness of natural gas as a fuel for new capacity builds, leading to higher prices and lower demand for electricity. Total generating capacity is similar in the Reference case and the Low Oil and Gas Resource case, but the large amount of renewable capacity built in the Low Oil and Gas Resource case—particularly wind and solar—does not contribute as much generation as NGCC capacity toward meeting either electricity demand or reserve margin requirements.

**Generation by fuel**

In the Reference case, coal-fired generation increases by an average of 0.2 percent per year from 2011 through 2040. Even though less capacity is available in 2040 than in 2011, the average capacity utilization of coal-fired generators increases over time. In recent years, as natural gas prices have fallen and natural gas-fired generators have displaced coal in the dispatch order, the average capacity factor for coal-fired plants has declined substantially. The coal fleet maintained an average annual capacity factor above 70 percent from 2002 through 2008, but the capacity factor has declined since then, falling to about 57 percent in 2012. As natural gas prices increase in the *AEO2013* Reference case, the utilization rate of coal-fired generators returns to previous historical levels and continues to rise, to an average of around 74 percent in 2025 and 78 percent in 2040. Across the alternative cases, coal-fired generation varies slightly in 2025 (Figure 30) and 2040 (Figure 31) as a result of differences in plant retirements and slight differences in utilization rates. The capacity factor for coal-fired power plants in 2040 ranges from 69 percent in the High Oil and Gas Resource case to 81 percent in the Low Oil and Gas Resource case.

Natural gas-fired generation varies more widely across the alternative cases, as a result of changes in the utilization of NGCC capacity, as well as the overall amount of combined-cycle capacity available. In recent years, the utilization rate for NGCC plants has increased, while the utilization rate for coal-fired steam turbines has declined. Capacity factors for the two technologies were about equal at approximately 57 percent in 2012. As natural gas prices rise in the Reference case, the average capacity factor for combined-cycle plants drops below 50 percent in the near term and remains between 48 percent and 54 percent over the remainder of projection period. In the High Oil and Gas Resource case, where combined-cycle generation is more competitive with existing coal-fired generation and the largest amount of new combined-cycle capacity is added, the average capacity factor for combined-cycle plants rises to 70 percent in the middle years of the projection period and remains about 63 percent through the remainder of the projection period. In the Low Oil and Gas Resource case, generation from combined-cycle plants is 37 percent lower in 2040 than in the Reference case, and the capacity factor for NGCC plants declines from around 45 percent in the mid term to 36 percent in 2040. Natural gas-fired generation in the Low Oil and Gas Resource case is replaced primarily with generation from new nuclear and renewable power plants. Similar fluctuations in natural gas-fired generation, but smaller in magnitude, are also seen across the coal cost cases.

The coal and natural gas shares of total electricity generation vary widely across the alternative cases. The coal share of total generation varies from 30 percent to 43 percent in 2025 and from 28 percent to 40 percent in 2040. The natural gas share varies from 22 percent to 36 percent in 2025 and from 18 percent to 42 percent in 2040. In the High Oil and Gas Resource case, natural gas becomes the dominant generation fuel after 2015, and its share of total generation is 42 percent in 2040 (Figure 32).

**Figure 30. Power sector electricity generation by fuel in five cases, 2011 and 2025 (billion kilowatthours)**

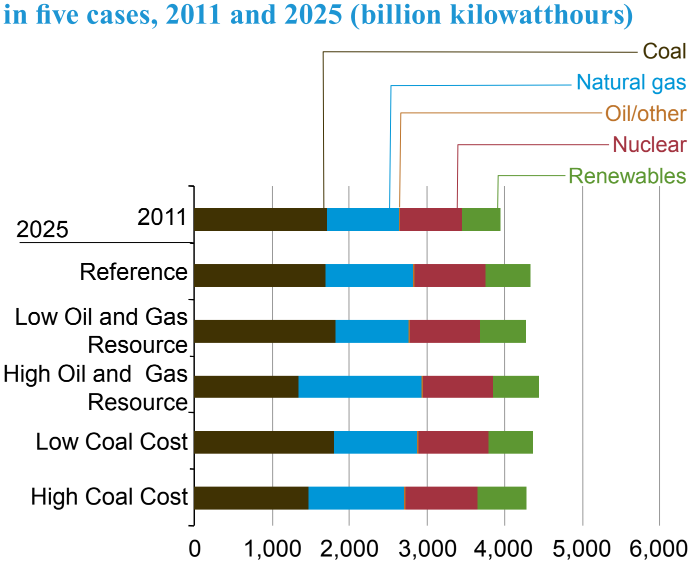
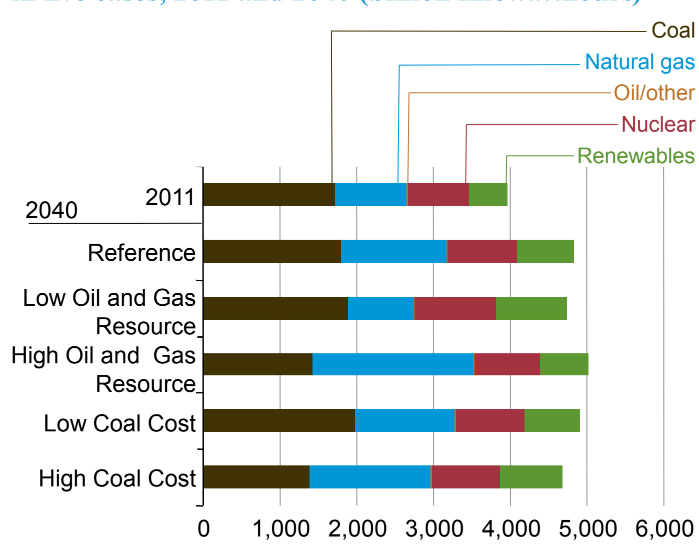



**Figure 31. Power sector electricity generation by fuel in five cases, 2011 and 2040 (billion kilowatthours)**



## Regional impacts

### Competition in the southeastern United States

While examining the national-level results is useful, the competition between coal and natural gas is best examined in a region that has significant amounts of both coal-fired and natural gas-fired capacity, such as the southeastern United States. In the southeastern subregion of the SERC Reliability Corporation (EMM Region 14), the ratio of average fuel costs for NGCC plants to average fuel costs for coal-fired steam turbines in both the High Coal Cost case and the High Oil and Gas Resource case is below that in the Reference case (Figure 33). In this region, which has a particularly efficient fleet of NGCC plants, the fuel cost ratios in both the High Coal Cost case and the High Oil and Gas Resource case remain near or below competitive parity for the majority of the projection period, indicating continued strong competition in the region. While average coal steam turbine heat rates remain largely static over the projection period, the average NGCC heat rates in this region drop appreciably by 2040, and are among the lowest in the nation.

The delivered cost of coal in the region is somewhat higher than in many other regions. Central Appalachian and Illinois Basin coals must be transported by rail or barge to the Southeast, and coal from the Powder River Basin must travel great distances by rail. The region also uses some imported coal, typically along the Gulf Coast, which tends to be more expensive.

In the High Oil and Gas Resource case, retirements of coal-fired generators in this region total 8 gigawatts in 2016 (5 gigawatts higher than in the Reference case) and remain at that level through 2040. Lower fuel prices for new natural gas-fired capacity, along with requirements to install environmental control equipment on existing coal-fired capacity, leads to additional retirements of coal-fired plants. As a result, the coal share of total capacity in the region drops from 39 percent in 2011 to 23 percent in 2040 in the High Oil and Gas Resource case, and the NGCC share rises from 24 percent in 2011 to 40 percent in 2040, when it accounts for the largest share of total generating capacity.

The capacity factors of coal-fired and NGCC power plants also vary across the cases, resulting in a significant shift in the shares of generation by fuel. The natural gas share of total electric power generation in the SERC southeast subregion grows from 31 percent in 2011 to 36 percent in 2040 in the Reference case, as compared with 56 percent in 2040 in the High Oil and Gas Resource case. Conversely, the coal share drops from 47 percent in 2011 to 40 percent in 2040 in the Reference case, compared with 20 percent in 2040 in the High Oil and Gas Resource case.

### Competition in the Midwest

In the western portion of the Reliability*First* Corporation (RFC) region (EMM Region 11), which covers Ohio, Indiana, and West Virginia as well as portions of neighboring states, the ratio of the average fuel cost for natural gas-fired combined-cycle plants to the average fuel cost for coal-fired steam turbines approaches parity in the High Coal Cost case and the High Oil and Gas Resource case (Figure 34). The RFC west subregion is more heavily dependent on coal, with coal-fired capacity accounting for 58 percent of the total in 2011. The coal share of total capacity falls to 48 percent in 2040 in the Reference case with the retirement of nearly 15 gigawatts of coal-fired capacity from 2011 to 2017. NGCC capacity, which represented only 7 percent of the region's total generating capacity in 2011, accounts for 11 percent of the total in 2040 in the Reference case.

**Figure 32. Power sector electricity generation from coal and natural gas in two cases, 2008-2040 (billion kilowatthours)**

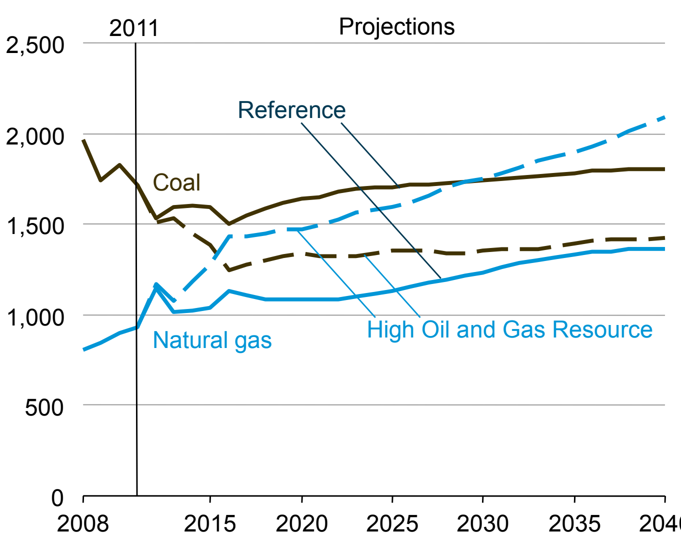
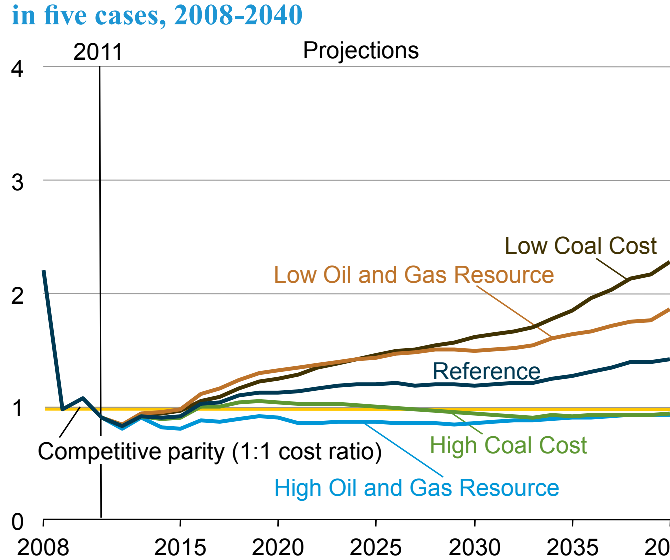



**Figure 33. Ratio of average per megawatthour fuel costs for natural gas combined-cycle plants to coal-fired steam turbines in the SERC southeast subregion in five cases, 2008-2040**



In the High Coal Cost case, only a limited amount of shifting from coal to natural gas occurs in this region, which has a large amount of existing coal-fired capacity and access to multiple sources of coal, including western basins as well as the Illinois and Appalachian basins. Higher transportation rates in this case deter the use of Western coal in favor of more locally sourced Interior and Appalachian coal. The ability to switch coal sources to moderate fuel expenditures reduces the economic incentive to build new NGCC plants, even with coal prices that are higher than those in the Reference case. The NGCC share of the region's total capacity does increase in the High Oil and Gas Resource case relative to the Reference case, to 16 percent in 2040. In all the cases, however, coal-fired generating capacity makes up more than 42 percent of the total in 2040.

The different capacity factors of coal-fired steam turbines and NGCC capacity contribute to a shift in the generation fuel shares, but the lower levels of natural gas-fired capacity in the region limit the impacts relative to those seen in the Southeast. The natural gas share of total generation in the region grows from 6 percent in 2011 to 8 percent in 2040 in the Reference case, 10 percent in 2040 in the High Coal Cost case, and 18 percent in 2040 the High Oil and Gas Resource case. Coal's share of the region's electric power sector generation declines from 66 percent in 2011 to 64 percent in 2040 in the Reference case, and to 54 percent in both the High Coal Cost case and the High Oil and Gas Resource case. In the High Coal Cost case, much of the coal-fired generation is replaced with biomass co-firing rather than natural gas, because without the lower natural gas prices in the High Oil and Gas Resource case, it is more economical to use biomass in existing coal-fired units than to build and operate new natural gas-fired generators.

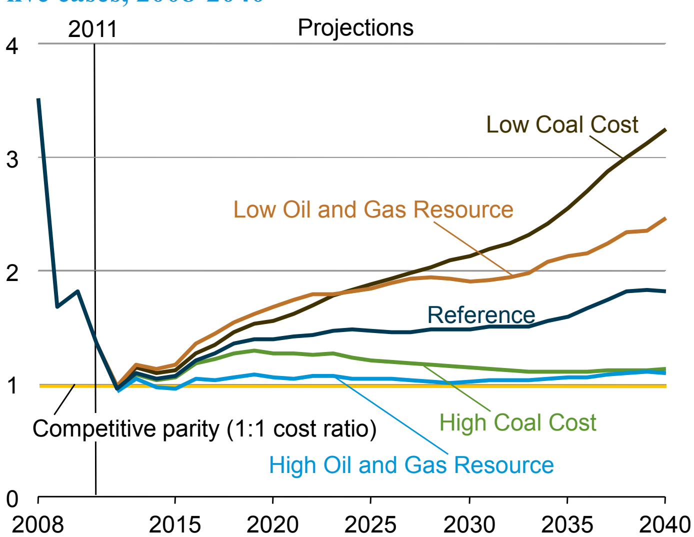
### Other factors affecting competition

In addition to relative fuel prices, a number of factors influence the competition between coal-fired steam turbines and natural gas-fired combined-cycle units. One factor in the dispatch-level competition is the availability of capacity of each type. In New England, for example, competition between coal and natural gas is not discussed, because very little coal-fired capacity exists or is projected to be built in that region, even in the *AEO2013* alternative fuel price cases. New England is located far from coal sources, and a regional cap on GHG emissions is in place, which makes investment in new coal-fired capacity unlikely. In the southeastern United States, however, there is more balance between natural gas-fired and coal-fired generating resources.

Further limitations not discussed above include:

- **Start-up and shutdown costs.** In general, combined-cycle units are considered to be more flexible than steam turbines. They can ramp their output up and down more easily, and their start-up and shutdown procedures involve less time and expense. However, plants that are operated more flexibly (i.e., ramping up and down and cycling on and off) often have higher maintenance requirements and higher maintenance costs.
- **Emission rates and allowance costs.** Another component of operating costs not mentioned above is the cost of buying emissions allowances for plants covered by the Acid Rain Program and Clean Air Interstate Rule. In recent years, allowance prices have dropped to levels that make them essentially negligible, although for many years they were a significant component of operating costs.
- **Transmission constraints on the electricity grid and other reliability requirements.** Certain plants, often referred to as reliability must-run plants, are located in geographic areas where they are required to operate whenever they are available. In other cases, transmission limitations on the grid at any given time may determine maximum output levels for some plants.

**Figure 34. Ratio of average per megawatthour fuel costs for natural gas combined-cycle plants to coal-fired steam turbines in the RFC west subregion in five cases, 2008-2040**




### 5. Nuclear power in *AEO2013*

In 2011, approximately 19 percent of the nation's electricity was generated by 104 operating commercial nuclear reactors, totaling 101 gigawatts of capacity. In the *AEO2013* Reference case, annual generation from nuclear power grows by 14.3 percent from the 2011 total to 903 gigawatthours in 2040. However, the nuclear share of the overall generation mix declines to 17 percent as growth in nuclear generation is outpaced by the increases in generation from natural gas and renewables. The Reference case projects the addition of 19 gigawatts of nuclear capacity from 2011 to 2040, in comparison with the addition of 215 gigawatts of natural gas capacity and 104 gigawatts of renewable capacity.

Nuclear capacity is added both through power uprates at existing nuclear power plants and through new builds. Uprates at existing plants account for 8.0 gigawatts of nuclear capacity additions in the Reference case and new construction adds 11.0 gigawatts of capacity over the projection period. About 5.5 gigawatts of new capacity results from Watts Bar Unit 2, Summer Units 2 and 3, and Vogtle Units 3 and 4, all of which are projected to be online by 2020. The *AEO2013* Reference case includes the retirement of 0.6 gigawatts at Oyster Creek in 2019, as well as retirements of an additional 6.5 gigawatts of capacity toward the end of the projection. *AEO2013* also includes several alternative cases that examine the impacts of different assumptions about the long-term operation of existing nuclear power plants, new builds, deployment of new technologies, and the impacts on electricity markets of different assumptions about future nuclear capacity.

### Uprates

Power uprates increase the licensed capacity of existing nuclear power plants and enable those plants to generate more electricity [*83*]. The U.S. Nuclear Regulatory Commission (NRC) must approve all uprate projects before they are undertaken and verify that the reactors will still be able to operate safely at the proposed higher levels of output. Power uprates can increase plant capacity by up to 20 percent of the original licensed capacity, depending on the magnitude and type of uprate project. Capital expenditures may be small (e.g., installing a more accurate sensor) or significant (e.g., replacing key plant components, such as turbines).

EIA relied on both reported data and estimates to define the uprates included in *AEO2013*. Reported data comes from the Form EIA-860 [*84*], which requires all nuclear power plant owners to report plans to build new plants or make modifications (such as an uprate) to existing plants within the next 10 years. In 2011, nuclear power plants reported plans to complete a total of 1.5 gigawatts of uprate projects over the next 10 years.

In addition to the reported uprates, EIA included an additional 6.5 gigawatts of uprates over the projection period. The inclusion of potential uprate capacity is based on interactions with EIA stakeholders who have significant experience in implementing power plant uprates.

### New Builds

Building a new nuclear power plant is a complex operation that can take more than a decade to complete. Projects generally require specialized high-wage workers, expensive materials and components, and engineering construction expertise, which can be provided by only a select group of firms worldwide. In the current economic environment of low natural gas prices and flat demand for electricity, the overall market conditions for new nuclear plants are challenging.

Nuclear power plants are among the most expensive options for new electric generating capacity [*85*]. The *AEO2013* Reference case assumes that the overnight capital costs (the cost before interest) associated with building a nuclear power plant in 2012 were $5,429 (2011 dollars) per kilowatt, which translates to almost $12 billion for a dual-unit 2,200-megawatt power plant. The estimate does not include such additional costs as financing, interest carried forward, and peripheral infrastructure updates [*86*]. Despite its cost, deployment of new nuclear capacity supports the long-term resource plans of many utilities by allowing fuel diversification and by providing a hedge against potential future GHG regulations or higher natural gas prices.

Incentive programs encourage the construction of new reactors in the United States. At the federal level, the Energy Policy Act of 2005 (EPACT2005) established a Loan Guarantee Program for new nuclear plants that are completed and operational by 2020 [*87*]. A total of $18.5 billion is available, of which $8.3 billion has been conditionally committed to the construction of Southern Company's Vogtle Units 3 and 4 [*88*]. EPACT2005 also provided a PTC of $18 per megawatt hour for electricity produced during the first 8 years of plant operation [*89*]. To be eligible for this credit, new nuclear plants must be operational by 2021, and the credit is limited to the first 6 gigawatts of new nuclear capacity. In addition to federal incentives, several states provide a favorable regulatory environment for new nuclear plants by allowing plant owners to recover their investments through retail electricity rates.

In addition to reported plans to build new nuclear power plants, another 5.5 gigawatts of unplanned capacity is built in the later years of the Reference case projection. Higher natural gas prices, growth in electricity demand, and the need to displace retired nuclear and coal-fired capacity all play a role in the growth at the end of the projection period in the Reference case.

### Retirements

NRC has the authority to issue initial operating licenses for commercial nuclear power plants for a period of 40 years. Decisions to apply for operating license renewals are made entirely by nuclear power plant owners, and typically they are based on economics and the ability to meet NRC requirements.

In April 2012, Oyster Creek Unit 1 became the first commercial nuclear reactor to have operated for 40 years, followed by Nine Mile Point Unit 1 in August, R. E. Ginna in September, and Dresden Unit 2 in December 2012. Two additional plants, H.B. Robinson Unit 2 and Point Beach Unit 1, will complete 40 years of operation in 2013. As of December 2012, the NRC had granted license renewals to 72 of the 104 operating U.S. reactors, allowing them to operate for a total of 60 years. Currently, the NRC is reviewing license renewal applications for 13 reactors, and 15 more applications for license renewals are expected between 2013 and 2019.

NRC regulations do not limit the number of license renewals a nuclear power plant may be granted. The nuclear power industry is preparing applications for license renewals that would allow continued operation beyond 60 years. The first such application, for permission to operate a commercial reactor for a total of 80 years is tentatively scheduled to be submitted in 2015. Aging plants may face a variety of issues that could lead to a decision not to apply for a second license renewal, including both economic and regulatory issues—such as increased operation and maintenance (O&M) costs and capital expenditures to meet NRC requirements. Industry research is focused on identifying challenges that aging facilities might encounter and formulating potential approaches to meet those challenges [*90*, *91*]. Typical challenges involve degradation of structural materials, maintaining safety margins, and assessing the structural integrity of concrete [*92*].

The outcome of pending research and market developments will be important to future decisions regarding life extensions beyond 60 years. The *AEO2013* Reference case assumes that the operating lives of most of the existing U.S. nuclear power plants will be extended at least through 2040. The only planned retirement included in the Reference case is the announced early retirement of the Oyster Creek nuclear power station in 2019, as reported on Form EIA-860. The Reference case also assumes an additional 7.1 gigawatts of nuclear power capacity retirements by 2040, representing about 7 percent of the current fleet. These generic retirements reflect uncertainty related to issues associated with long-term operations and age management.

In March 2012, the NRC issued three orders [*93*] that require nuclear power plants to implement requirements related to lessons learned from the accident at Japan's Fukushima Daiichi nuclear power plant in March 2011. Compliance assessments are underway currently at U.S. nuclear power plants. The requirements of the orders must be implemented by December 2016 and will remain in place until they are superseded by rulemaking. Given the evolving nature of NRC's regulatory response to the accident at Fukushima Daiichi, the Reference case does not include any retirements that could result from new NRC requirements that may involve plant modifications to meet such requirements.

### Small Modular Reactors

Small Modular Reactor (SMR) technology differs from traditional, large-scale light-water reactor technology in both reactor size and plant scalability. SMRs are typically smaller than 300 megawatts and can be built in modular arrangements. Traditional reactors are generally 1,000 megawatts or larger. The initial estimates for scalable SMRs range from 45 to 225 megawatts. SMRs are small enough to be fabricated in factories and can be shipped to sites via barge, rail, or truck. Those factors may reduce both capital costs and construction times. Smaller SMRs offer utilities the flexibility to scale nuclear power production as demand changes.

The actual construction of a large nuclear power plant can take up to a decade. During construction, the plant owner may incur significant interest costs and risk further cost increases because of delays and cost overruns. SMRs have the potential to mitigate some of the risks, based on their projected construction period of 3 years. Moody's credit rating agency has described large nuclear power plants as bet-the-farm endeavors for most companies, given the size of the investment and length of time needed to build a nuclear power facility [*94*], as highlighted by comparisons of the costs of building nuclear power plants with the overall sizes of the companies building them. *AEO2013* assumes that the overnight cost of a 2,200-megawatt nuclear power plant is approximately $12 billion, which is a significant share of the market capitalization of some of the nation's largest electric power companies. For example, the largest publicly traded company that owns nuclear power plants in the United States has a market capitalization of about $50 billion [*95*].

Although SMRs may offer several potential advantages, there are key issues that remain to be resolved. SMRs are not yet licensed by the NRC. While there are many similarities between SMRs and traditional large reactors, there are several key differences identified by the NRC that will need to be reviewed before a design certification is issued. Until the situation is clarified, there will be substantial uncertainty about the final costs of SMRs. In addition, the NRC must develop a regulatory infrastructure to support licensing review of the SMR designs. The NRC has identified several potential policy and technical issues associated with SMR licensing [*96*]. In August 2012, the NRC provided a report to Congress that addressed the licensing of reactors, including SMRs [*97*, *98*].

Ultimately, the path to commercialization for SMRs is to develop the infrastructure to manufacture the modules in factories and then ship the completed units to plant sites. Performing a majority of the construction in factories could standardize the assembly process and result in cost savings, as has occurred with U.S. Navy shipbuilding, where construction cost savings have been achieved by centralizing much of the production in a controlled factory setting [*99*].

In March 2012, DOE announced its intention to provide $450 million in funding to assist in the initial development of SMR technology [*100*]. Through cost-sharing agreements with private industry, DOE solicited proposals for promising SMR projects that have the potential to be licensed by the NRC and achieve commercial operation by 2022. In November 2012, DOE announced the selection of Babcock & Wilcox [*101*], in partnership with the Tennessee Valley Authority (TVA) and Bechtel International, to share the costs of preparing a license application for up to four SMRs at TVA's Clinch River site in Oak Ridge, Tennessee.

### Alternative nuclear cases

In the *AEO2013* Low Nuclear case, uprates currently under review by, or expected to be submitted to, the NRC are not included unless they have been reported to EIA. No nuclear power plants are assumed to receive second license renewals in the Low Nuclear case; all plants are assumed to retire after roughly 60 years of operation, except for those specifically discussed below. Other than the 5.5 gigawatts of new capacity already planned, no new nuclear power plants are assumed to be built.

In addition to the retirement of Oyster Creek in 2019, the Low Nuclear case includes the retirement of Kewaunee in 2013. Nuclear power plants that are in long-term shutdown also are assumed to be retired, including San Onofre Nuclear Generating Station (SONGS) Unit 3 and Crystal River Unit 3. Both plants have been in extended shutdown for more than a year, and there is substantial uncertainty about the cost and feasibility of operating the facilities in the future. Southern California Edison is assessing the long-term viability of SONGS Unit 3 and has indicated that it will not be operating for some time, in light of ongoing steam generator issues [*102*, *103*, *104*]. Crystal River Unit 3 has been offline since September 2009, as a result of cracks in the containment structure. As of October 2012, replacement power costs and the repairs to Unit 3 were initially estimated to be between $1.3 and $3.5 billion. However, repairs could eventually include replacement of the entire containment structure. Further repairs to Crystal River Unit 3 are being evaluated [*105*, *106*]. In the Reference and High Nuclear cases, SONGS Unit 3 and Crystal River Unit 3 are assumed to return to service when maintenance and repairs have been completed.

The High Nuclear case assumes that all existing nuclear power plants receive their second license renewals and operate through 2040. Uprates in the High Nuclear case are consistent with those in the Reference case (8.0 gigawatts added by 2025). In addition to plants already under construction, the High Nuclear case assumes that nuclear power plants with active license applications at the NRC are constructed, provided that they have a tentatively scheduled Atomic Safety and Licensing Board hearing and will deploy a certified Nuclear Steam Supply System design. This assumption results in the planned addition of 13.3 gigawatts of new nuclear capacity, which is 7.8 gigawatts above what is assumed in the Reference case.

In the High Nuclear case, planned capacity additions are more than double those in the Reference case, but unplanned additions do not change noticeably. The additional planned capacity reduces the need for new unplanned capacity. The importance of natural gas prices for nuclear power plant construction is highlighted in the results of the Low Oil and Gas Resource case, where the average price of natural gas delivered to the electric power sector in 2040 is 26 percent higher than in the Reference case. The higher natural gas prices make nuclear power a more competitive source for new generating capacity, resulting in the addition of 26 gigawatts of unplanned nuclear power capacity from 2011 to 2040. In the High Oil and Gas Resource case, where the average price of natural gas delivered to the electric power sector in 2040 is 39 percent lower than in the Reference case, no unplanned nuclear capacity is built. Similarly, no unplanned nuclear capacity is added in the Low Nuclear case (Figure 35).

The Small Modular Reactor case assumes that SMRs will be the nuclear technology choice available after 2025, rather than traditional gigawatt-scale nuclear power plants. There is uncertainty surrounding SMR design certification and supply chain and infrastructure development, which makes it difficult to develop capital cost assumptions for SMRs. The Small Modular Reactor case assumes that SMRs have the same overnight capital costs per kilowatt as a traditional 1,100-megawatt unit, consistent with cost assumptions in the Reference case. This assumption was made for the purpose of assessing the impact on the amount of new nuclear capacity of a shorter construction period for SMRs than for traditional nuclear power plants.

In the High Nuclear case, nuclear generation in 2040 is 12 percent higher than in the Reference case, and the nuclear share of total generation is 19 percent, compared with 17 percent in the Reference case. The increase in nuclear generation offsets a decline in generation from natural gas (Figure 36) and renewable fuels, which are 5 percent and 2 percent lower in 2040, respectively, than in the Reference case. Coal-fired generation in the High Nuclear case is virtually the same as in the Reference case.

In the Low Nuclear case, generation from nuclear power in 2040 is 44 percent lower than in the Reference case, due to the loss of 45.4 gigawatts of nuclear capacity that is retired after 60 years of operation. As a result, the nuclear share of total generation falls to 10 percent in 2040. The loss of generation is made up primarily by increased generation from natural gas, which is 17 percent higher in the Low Nuclear case than in the Reference case in 2040. Generation from coal and generation from renewables in 2040 both are 2 percent higher than projected in the Reference case.

$CO_2$ emissions from the electric power sector are affected by the share of nuclear power in the generation mix. Unlike coal- and natural gas-fired plants, nuclear power plants do not emit $CO_2$. Consequently, $CO_2$ emissions from the electric power sector in 2040 are 5 percent lower in the Reference case than in the Low Nuclear case, as a result of switching from nuclear generation to

**Figure 35. Nuclear capacity additions in five cases, 2011-2040 (gigawatts)**

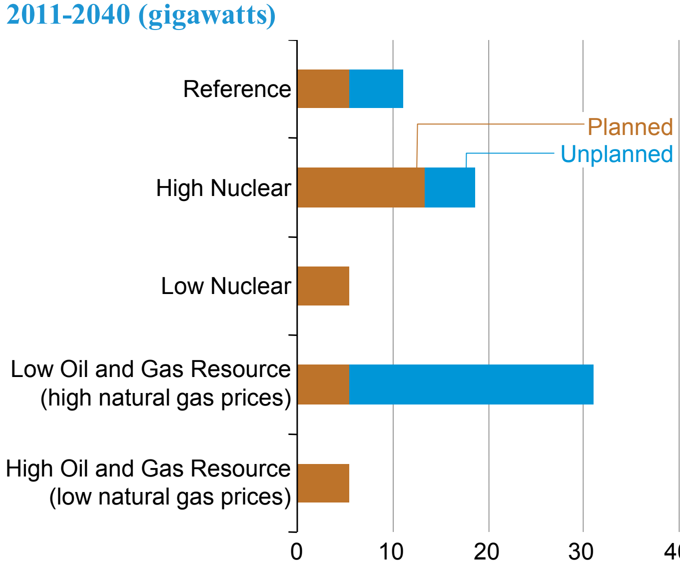
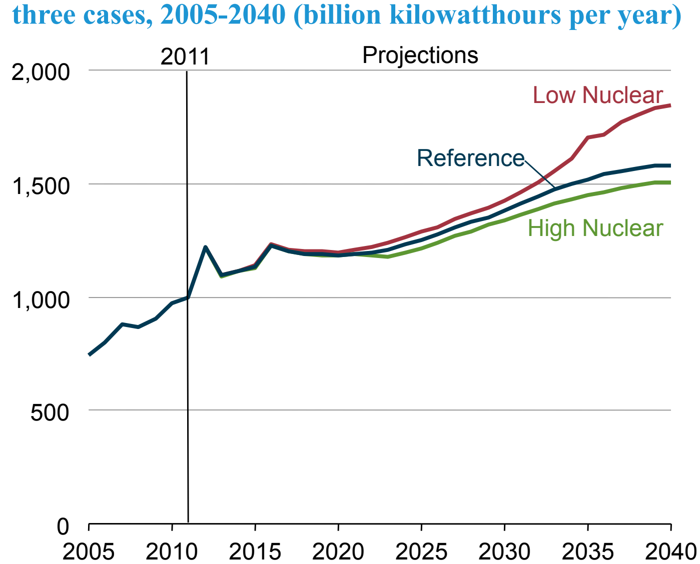



**Figure 36. Electricity generation from natural gas in three cases, 2005-2040 (billion kilowatthours per year)**



mostly natural gas and some coal [107]. In the High Nuclear case, $CO_2$ emissions from the power sector are 1 percent lower than projected in the Reference case, because the High Nuclear case results in slightly more generation from nuclear units than from fossil-fueled units (Figure 37).

Real average electricity prices in 2040 are 1 percent lower in the High Nuclear case than in the Reference case, as slightly less natural gas capacity is dispatched, reducing natural gas prices, which lowers the marginal price of electricity. In the Low Nuclear case, average electricity prices in 2040 are 5 percent higher than in the Reference case as a result of the retirement of a significant amount of nuclear capacity, which has relatively low operating costs, and its replacement with natural gas capacity, which has higher fuel costs that are passed through to consumers in retail electricity prices.

The impacts of nuclear plant retirements on retail electricity prices in the Low Nuclear case are more apparent in regions with relatively large amounts of nuclear capacity. For example, electricity prices in the Low Nuclear case are 9 percent higher in 2040 than in the Reference case for the SERC (Southeast) region, 8 percent higher for the MRO (Midwest) region, and 6 percent higher in the Northeast, Mid-Atlantic, and Ohio River Valley regions [*108*]. Even in regions where no nuclear capacity is retired, there are small increases in electricity prices compared to the Reference case, because higher demand for natural gas in regions where nuclear plants are retired increases the price of natural gas in all regions.

In the Small Modular Reactor case, shorter construction periods result in lower interest costs, which help to reduce the overall cost of nuclear construction projects. Figure 38 compares the resulting levelized costs for traditional large reactors and for SMRs in the Reference case. For SMRs, there is a savings of approximately $6 per megawatthour in the capital portion of the levelized cost. However, estimates of the fixed O&M costs for SMRs, derived from a University of Chicago study [*109*], are 40 percent higher than those assumed in *AEO2013* for a new large-scale plant on a dollar per megawatt basis. The higher O&M cost could offset, in part, the capital cost benefit of a shorter construction period. Therefore, the SMR case shows only a 1.4-percent reduction in overall levelized cost relative to the Reference case. The small difference results in about 2.3 gigawatts more new nuclear power capacity in the Small Modular Reactor case than projected in the Reference case. The sensitivity to small changes in cost is notable, given the high degree of uncertainty associated with SMR costs based on the maturity of the technology.

## 6. Effect of natural gas liquids growth

### Background

NGL include a wide range of components produced during natural gas processing and petroleum refining. As natural gas production in recent years has grown dramatically, there has been a concurrent rapid increase in NGL production. NGL include ethane, propane, normal butane (n-butane), isobutane, and pentanes plus. The rising supply of some NGL components (particularly ethane and propane) has led to challenges, in finding markets and building the infrastructure necessary to move NGL to the new domestic demand and export markets. This discussion examines recent changes in U.S. NGL markets and how they might evolve under several scenarios. The future disposition of U.S. NGL supplies, particularly in international markets, is also discussed.

Recent growth in NGL production (Figure 39) has resulted largely from strong growth in shale gas production. The lightest NGL components, ethane and propane, account for most of the growth in NGL supply between 2008 and 2012. With the exception of propane, the main source of NGL is natural gas processing associated with growing natural gas production. That growth has led to

**Figure 37. Carbon dioxide emissions from electricity generation in three cases, 2005-2040 (million metric tons carbon dioxide equivalent per year)**

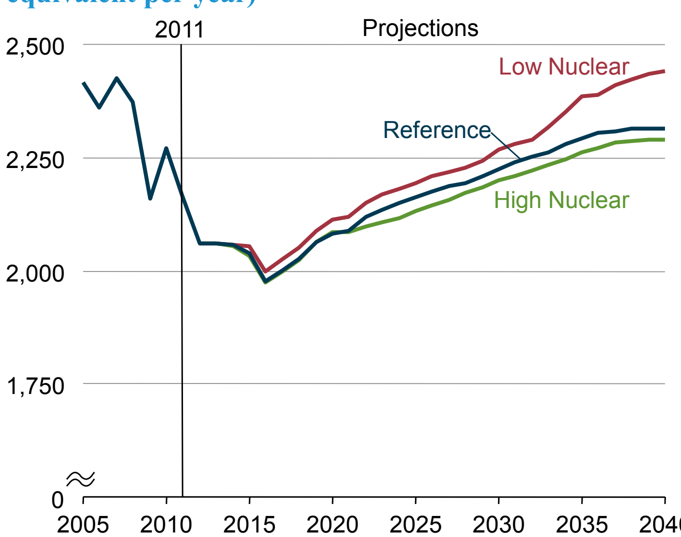
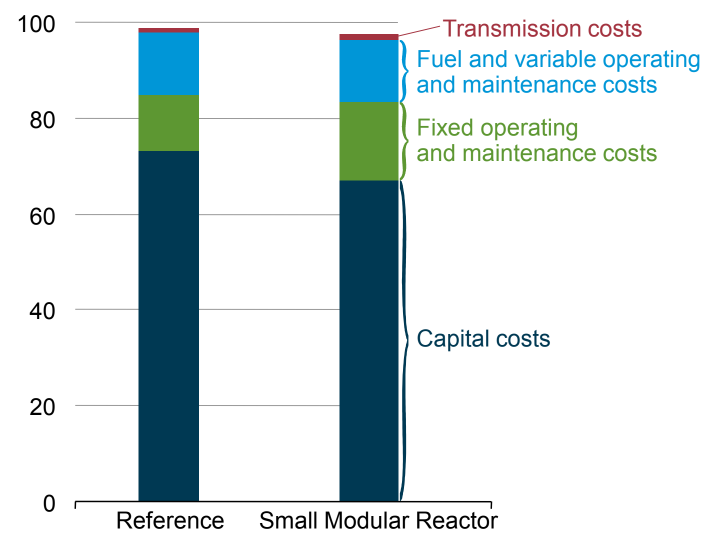



**Figure 38. Levelized costs of nuclear electricity generation in two cases, 2025 (2011 dollars per megawatthour)**



logistical problems in some areas. For example, much of the increased ethane supply in the Marcellus region is stranded because of the distance from petrochemical markets in the Gulf Coast area.

The uses of NGL are diverse. The lightest NGL component, ethane, is used almost exclusively as a petrochemical feedstock to produce ethylene, which in turn is a basic building block for plastics, packaging materials, and other consumer products. A limited amount of ethane can be left in the natural gas stream (ethane rejection) if the value of ethane sinks too close to the value of dry natural gas, but the amount of ethane mixed in dry natural gas is small. Propane is the most versatile NGL component, with applications ranging from residential heating, to transportation fuel for forklifts, to petrochemical feedstock for propylene and ethylene production (nearly one-half of all propane use in the United States is as petrochemical feedstock). Butanes are produced in much smaller quantities and are used mostly in refining (for gasoline blending or alkylation) or as chemical feedstock. The heaviest liquids, known as pentanes plus, are used as ethanol denaturant, blendstock for gasoline, chemical feedstock, and, more recently, as diluent for the extraction and pipeline movement of heavy crude oils from Canada.

Unlike the other NGL components, a large proportion of propane is produced in refineries (which is mixed with refinery-marketed propylene). Given that refinery production of propane and propylene has been largely unchanged since 2005 at about 540 thousand barrels per day, the growth of propane/propylene supply shown in Figure 39 is solely a result of increased propane yields from natural gas processing plants.

International demand for NGL has provided an outlet for growing domestic production, and after years of being a net importer, the United States became a net exporter of propane in 2012 (Figure 40). Although the quantities shown in Figure 40, based on EIA data, represent an aggregated mixture of propane and propylene, other sources indicate that U.S. propylene exports have been on the decline since 2007 [*110*], implying that the recent change to net exporter status is the result of increased supplies of propane from natural gas processing plants.

## Current developments in NGL markets

The market currently is reacting to the growing supply of ethane and propane by expanding both domestic use of NGL and export capacity. On the domestic side, much of the U.S. petrochemical industry can absorb ethane and propane by switching from heavier petroleum-based naphtha feedstock in ethylene crackers to lighter feedstock, and recent record low NGL prices have motivated petrochemical companies to maximize the amount of ethane and propane in their feedstock slate. To take advantage of the expected growth in supplies of light NGL components resulting from shale gas production, multiple projects and expansions of petrochemical crackers have been announced (Table 7).

Although the proposed projects shown in Table 7 will largely take advantage of the growing ethane supply, a few petrochemical projects that will use propane directly as a propylene feedstock through propane dehydrogenation also have been announced [*111*]. Although expanded feedstock use is expected to be by far the largest source of expanded demand for NGL, increased use of NGL as a fuel, especially propane, also is expected—including the marketing of propane as an alternative vehicle fuel [*112*] and for agricultural use, with propane suppliers currently offering incentives for farmers to use propane as a fuel to power irrigation systems [*113*].

Notwithstanding the efforts to encourage the use of propane as a fuel in the United States, and despite current low prices, opportunities to expand the market for propane in uses other than as feedstock are limited. Therefore, producers, gas processors, and fractionators are looking for a growing export outlet for both ethane and liquefied petroleum gases (LPG—a mixture of

**Figure 39. U.S. production of natural gas liquids by type, 2005-2012 (million barrels per day)**

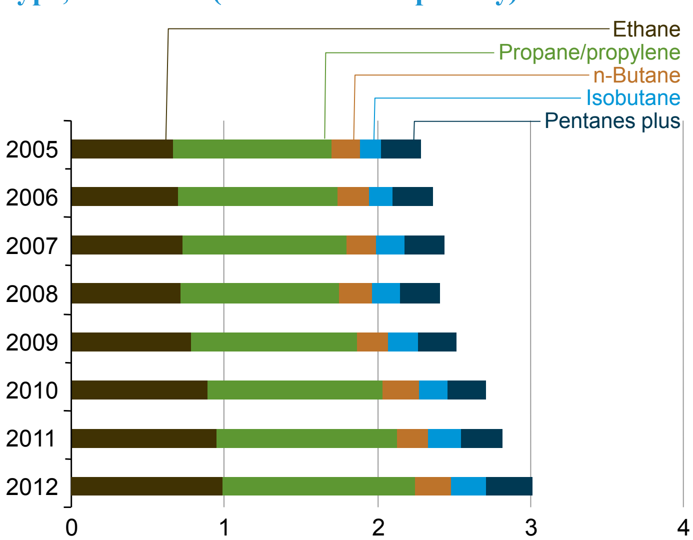
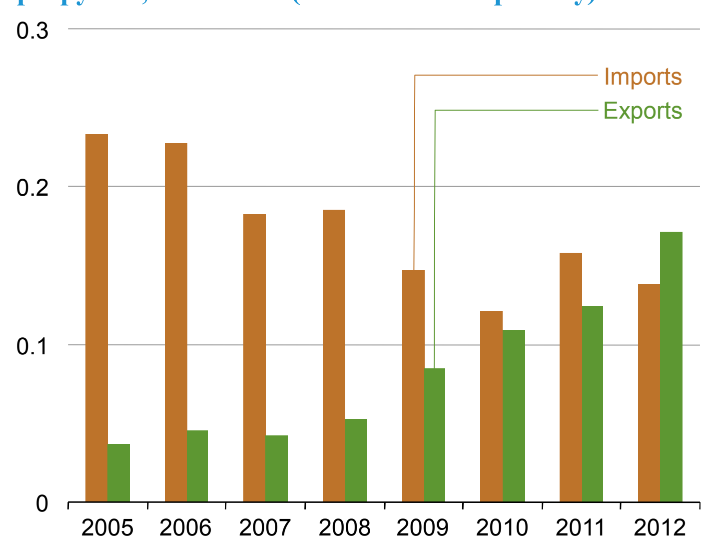



**Figure 40. U.S. imports and exports of propane/ propylene, 2005-2012 (million barrels per day)**



propane and butane). Export capacity is being expanded, both on the U.S. Gulf Coast (Targa's expansion of both its gas processing and fractionation capability at Mont Belvieu and its export facility at Galena Park [*114*]) and on the U.S. East Coast (Sunoco Logistics' Mariner East project to supply propane and ethane to Philadelphia's Marcus Hook terminal [*115, 116*]). Exports of ethane from the Marcellus shale to chemical facilities in Sarnia, Ontario, via the Mariner West pipeline system, and from the Bakken formation to a NOVA Chemical plant near Joffre, Alberta, via the Vantage pipeline [*117*], are expected by the end of 2013. In addition to planned exports to Canada, a pipeline is being developed to transport ethane from the Marcellus to the Gulf Coast to relieve oversupply. The midstream sector's rapid buildup and expansion of natural gas processing, pipeline, and storage capacity have accommodated increasing volumes of NGL resulting from the sharp growth in shale gas production.

### *AEO2013* projections

*AEO2013* projects continued growth in both natural gas production and NGL supplies, with NGL prices determined in large part by Brent crude oil prices and Henry Hub spot prices for natural gas (Figure 41). In the *AEO2013* Reference, Low Oil and Gas Resource, and High Oil and Gas Resource cases, industrial propane prices in 2040 range from $22.13 per million Btu (2011 dollars) in the High Oil and Gas Resource case to $27.48 per million Btu in the Low Oil and Gas Resource case, a difference of approximately 24 percent. The difference between the propane prices in the High and Low Oil and Gas Resource cases increases from $3.49 per million Btu in 2015 to $7.00 per million Btu in 2025 as natural gas prices and NGL production diverge in the two cases. Over time, however, as the divergence in NGL production narrows between the cases, the influence of oil prices on propane prices increases, and the difference in the propane prices narrows in the cases.

Production of NGPL, which are extracted from wet natural gas by gas processors, rises more steeply than natural gas production in the first half of the projection period as a result of increased natural gas and oil production from shale wells, which have relatively high liquids contents. As shale gas plays mature, NGPL production levels off or declines even as dry natural gas production increases (Figure 42).

Variations in NGL supplies and prices contribute to variations in demand for NGL. In the High Oil and Gas Resource case, propane demand in all sectors is higher than projected in the Reference case, and in the Low Oil and Gas Resource case propane demand is lower than in the Reference case. Some of the difference results from changes in the expected energy efficiency of space heating equipment in the residential sector, and possibly some fuel switching, in response to

**Table 7. Proposed additions of U.S. ethylene production capacity, 2013-2020 (million metric tons per year)**

| Company | Location | Proposed capacity |
|---|---|---|
| Chevron Phillips | Baytown, TX | 1.5 |
| Exxon Mobil | Baytown, TX | 1.5 |
| Sasol | Lake Charles, LA | 1.4 |
| Dow | Freeport, TX | 1.4 |
| Shell | Beaver Co, PA | 1.3 |
| Formosa | Point Comfort, TX | 0.8 |
| Occidental/ Mexichem | Ingleside, TX | 0.5 |
| Dow | St. Charles, LA | 0.4 |
| LyondellBasell | Laporte, TX | 0.4 |
| Aither Chemicals | Kanawha, WV | 0.3 |
| Williams/Sabic JV | Geismar, LA | 0.2 |
| Ineos | Alvin, TX | 0.2 |
| Westlake | Lake Charles, LA | 0.2 |
| Williams/Sabic JV | Geismar, LA | 0.1 |
| **Total** | | **10.1** |

**Figure 41. U.S. Brent crude oil and Henry Hub natural gas spot market prices in three cases, 2005-2040**

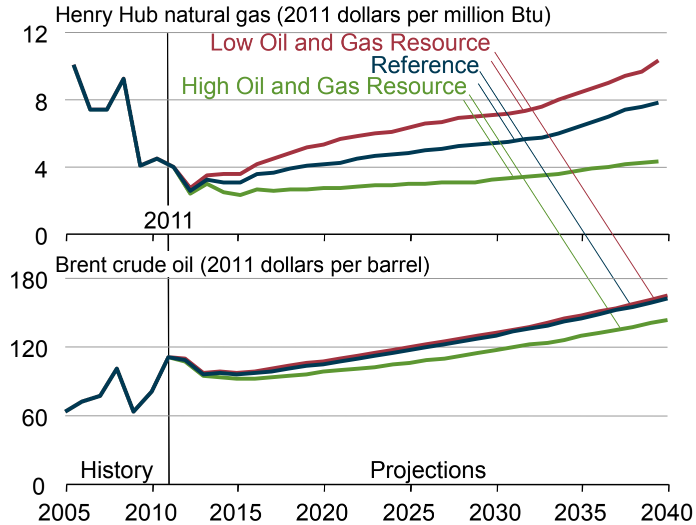
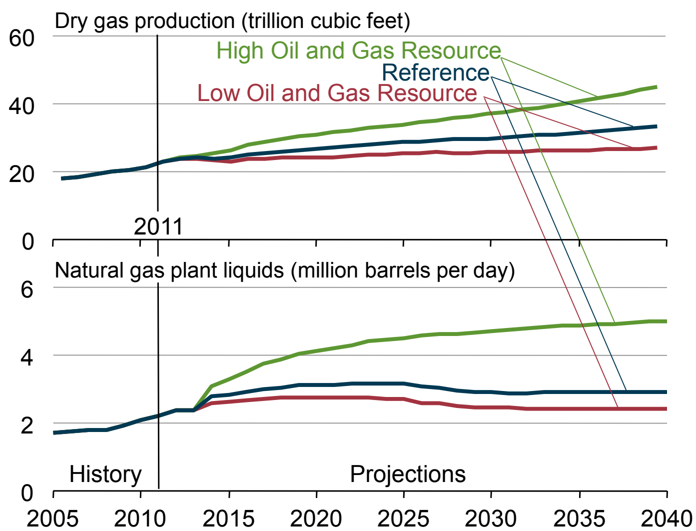



**Figure 42. U.S. production of dry natural gas and natural gas plant liquids in three cases, 2005-2040**



different price levels in the three cases. The remainder is attributed to variations in NGL feedstock consumption in the bulk chemicals sector, where the use of NGL as a fuel and feedstock varies with different price levels. In addition, because NGL feedstock competes with petroleum naphtha in the petrochemical industry, lower NGL prices relative to oil prices lead to more NGL consumption in the petrochemical industry.

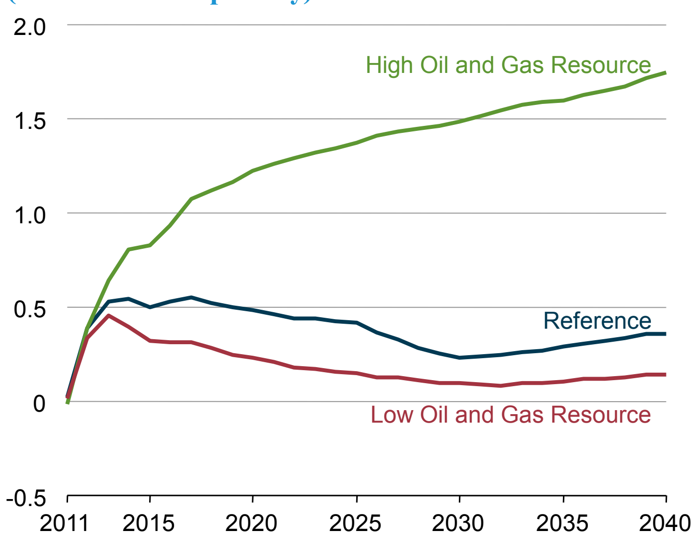
The LPG import-export balance changes rapidly when domestic supply exceeds demand. This trend continues in the near term in all three cases. In the High Oil and Gas Resource case, however, with more LPG production, net exports continue to grow throughout the projection (Figure 43). Propane accounts for most of the higher export volumes, which also include smaller amounts of butane and ethane. Currently, most U.S. exports of LPG go to Latin America, where LPG is used for heating and cooking.

### International implications

The projected growth in NGL demand both for U.S. domestic uses and for export depends heavily on international markets. Current plans for ethane exports are limited to pipelines to Canada, and to date ethane is not shipped by ocean-going vessels. There is room for growth in propane exports, however, because propane is a far more versatile fuel. Propane exports to Latin America are expected to continue, along with some expansion into European markets. In addition, growing markets in Africa [*118*] for propane used in heating and cooking, along with continued demand from Asia (for fuel and feedstock), are expected to support exports of propane from both the United States and the Middle East. It remains to be seen how the market for propane exports will develop in the long term, and how the United States will seek value for its propane—converting it into chemicals for domestic use or for export, or exporting raw propane.

International markets also play a role in increased domestic consumption, particularly for expanded petrochemical feedstock consumption. The declining price of ethane improves the economics of ethylene crackers, as indicated by the planned capacities shown in Table 7. The new capacity suggests that companies are planning to gain a greater market share of ethylene demand in Asia, especially in China, which continues to be a growing importer of ethylene [*119*]. However, that economic advantage has to be weighed against the massive growth in chemical manufacturing complexes in the Middle East, as well as expansions in Asia. Feedstock availability will not be a concern in the Middle East, but most petrochemical plants in China and other Asian countries rely heavily on naphtha as a feedstock, and naphtha is produced from crude oil, which China imports. China is making efforts to diversify its feedstock slate and has announced plans to build coal-to-olefins plants [*120*]. In addition, China may develop its own shale gas resources over the next 10 to 15 years, which could provide less expensive supplies of ethane and propane. The advantage in the Middle East is its long-term access to feedstocks. Whether the United States can further capitalize on growth in basic chemical production (ethylene, propylene) to build up its higher-value chemical base, and how the production cost of those higher value chemicals would compete with those from Asia and the Middle East, is an open question.

**Figure 43. U.S. net exports of liquefied petroleum gases in three cases, 2011-2040 (million barrels per day)**




Future plans for U.S. propane disposition will be based on the balance between growth in domestic demand and exports. Rising exports of propane and butane raise issues as well. For example, both propane and butane can be used not only as feedstock in ethylene crackers, but also as feedstock for specific chemical product. For example, dehydrogenation processes can make propylene from propane [*121*] and butadiene from butane [*122*]. The economic value of those chemicals (which would depend on both local and global markets), weighed against the export value of the NGL inputs (propane and butane), will need to be assessed. In addition, the value of derivatives (such as polyethylene and polypropylene) will be considered from the perspective of both their export value and their production costs, which will be tied directly to the price of their precursor inputs, ethylene and propylene. Finally, U.S. refineries produce a significant amount of propylene. There is some degree of flexibility within refineries' fluid catalytic cracker units to produce propylene [*123*], and future refinery production of propylene will depend on the value of propylene itself, the value of its co-products (mostly gasoline and propane), and refining costs.

# Endnotes for Issues in focus

**Links current as of March 2013**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71. Liquid fuels consists of crude oil and condensate to petroleum refineries, refinery gain, NGPL, biofuels, and other liquid fuels produced from non-crude oil feedstocks such as CTL and GTL.
72. Geologic characteristics relevant for hydrocarbon extraction include depth, thickness, porosity, carbon content, pore pressure, clay content, thermal maturity, and water content.
73. A production type curve represents the expected production each year from a well. A well's EUR equals the cumulative production of that well over a 30-year productive life, using current technology without consideration of economic or operating conditions. A description of a production type curve is provided in the *Annual Energy Outlook 2012* "Issues in focus" article, "U.S. crude oil and natural gas resource uncertainty," http://www.eia.gov/forecasts/archive/aeo12/IF_all.cfm#uscrude.
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# Market trends

Projections by the U.S. Energy Information Administration (EIA) are not statements of what will happen but of what might happen, given the assumptions and methodologies used for any particular case. The Reference case projection is a business-as-usual estimate, given known market, demographic, and technological trends. Most cases in the *Annual Energy Outlook 2013 (AEO2013)* generally assume that current laws and regulations are maintained throughout the projections. Such projections provide a baseline starting point that can be used to analyze policy initiatives. EIA explores the impacts of alternative assumptions in other cases with different macroeconomic growth rates, world oil prices, rates of technology progress, and policy changes.

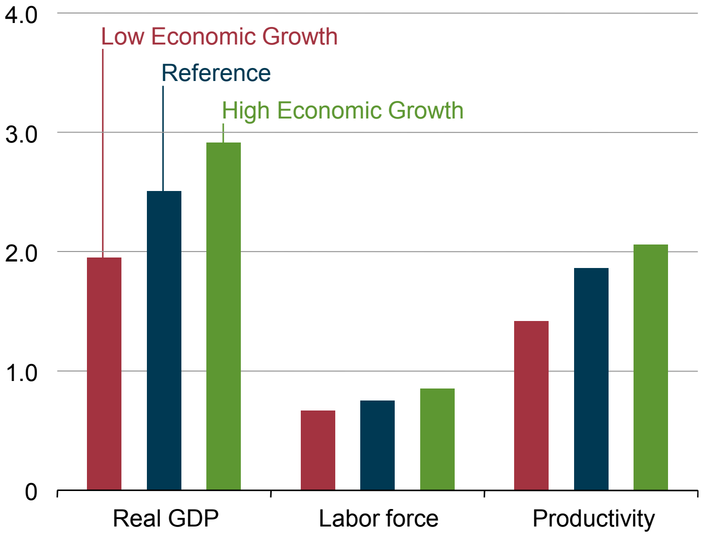
While energy markets are complex, energy models are simplified representations of energy production and consumption, regulations, and producer and consumer behavior. Projections are highly dependent on the data, methodologies, model structures, and assumptions used in their development. Behavioral characteristics are indicative of real-world tendencies rather than representations of specific outcomes.

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 *AEO2013* 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 as a substitute for, a complete and focused analysis of public policy initiatives.

## Productivity and investment offset slow growth in labor force

**Figure 44. Average annual growth rates of real GDP, labor force, and productivity in three cases, 2011-2040 (percent per year)**



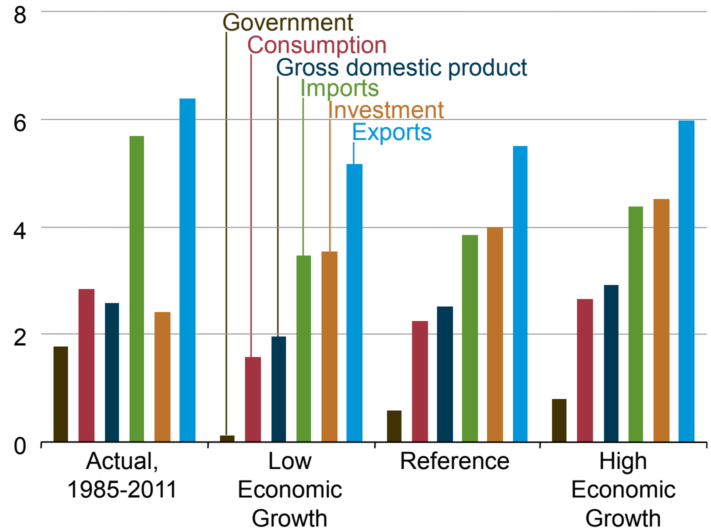

Growth in the output of the U.S. economy depends on increases in the labor force, the growth of capital stock, and improvements in productivity. In the *Annual Energy Outlook 2013 (AEO2013)* Reference case, U.S. labor force growth slows over the projection period as the baby boom generation starts to retire, but projected growth in business fixed investment and spending on research and development offsets the slowdown in labor force growth. Annual real gross domestic product (GDP) growth averages 2.5 percent per year from 2011 to 2040 in the Reference case (Figure 44), which is 0.2 percentage point slower than the growth rate over the past 30 years. Slow long-run increases in the labor force indicate more moderate long-run employment growth, with total civilian employment rising by an average of 1.0 percent per year from 2011 to 2040, from 131 million in 2011 to 174 million in 2040. The manufacturing share of total employment continues to decline over the projection period, falling from 9 percent in 2011 to 6 percent in 2040.

Real consumption growth averages 2.2 percent per year in the Reference case. The share of GDP accounted for by personal consumption expenditures varies between 66 percent and 71 percent of GDP from 2011 to 2040, with the share spent on services rising mainly as a result of increasing expenditures on health care. The share of GDP devoted to business fixed investment ranges from 10 percent to 17 percent of GDP through 2040.

Issues such as financial market reform, fiscal policies, and financial problems in Europe, among others, affect both short-run and long-run growth, adding uncertainty to the projections.

## Slow consumption growth, rapid investment growth, and an increasing trade surplus

**Figure 45. Average annual growth rates for real output and its major components in three cases, 2011-2040 (percent per year)**



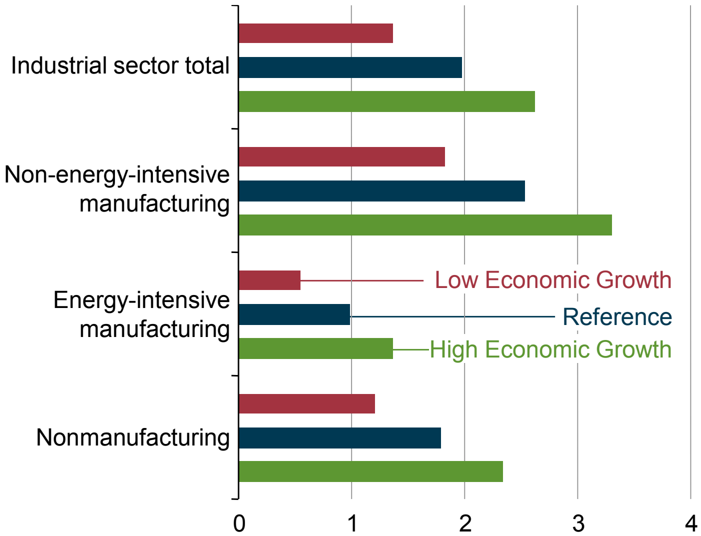

*AEO2013* presents three economic growth cases: Reference, High, and Low. The High Economic Growth case assumes high growth and low inflation. The Low Economic Growth case assumes low growth and high inflation. The short-term outlook (5 years) in each case represents current thinking about economic activity in the United States and the rest of the world, about the impacts of fiscal and monetary policies, and about potential risks to economic activity. The long-term outlook includes smooth economic growth, assuming no shocks to the economy.

Differences among the Reference, High, and Low Economic Growth cases reflect different expectations for growth in population (specifically, net immigration), labor force, capital stock, and productivity, which are above trend in the High Economic Growth case and below trend in the Low Economic Growth case. The average annual growth rate for real GDP from 2011 to 2040 in the Reference case is 2.5 percent, as compared with 2.9 percent in the High Economic Growth case and 2.0 percent in the Low Economic Growth case.

Figure 45 compares the average annual growth rates for output and its major components in each of the three cases. Compared with the 1985-2011 period, investment growth from 2011 to 2040 is faster in all three cases, whereas consumption, government expenditures, imports, and exports grow more slowly in all three cases. Opportunities for trade are assumed to expand in all three cases, resulting in real trade surpluses that continue to grow throughout the projection period.

## Energy-intensive industries show strong early growth in output

**Figure 46. Sectoral composition of industrial shipments, annual growth rates in three cases, 2011-2040 (percent per year)**




In recent decades, industrial sector shipments expanded more slowly than the overall economy, with imports meeting a large share of demand for goods and the service sector growing rapidly [*124*]. In the Reference case, real GDP grows at an average annual rate of 2.5 percent from 2011 to 2040, while the industrial sector increases by 2.0 percent per year (Figure 46).

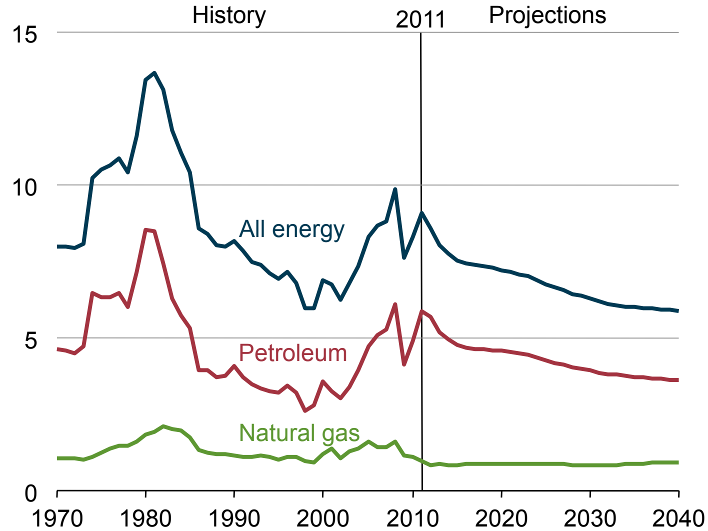
Industrial sector output goes through two distinct growth periods in the *AEO2013* Reference case, with energy-intensive industries displaying the sharpest contrast between the periods. Recovery from the recession in the U.S. industrial sector has been relatively slow, with only mining, aluminum, machinery, and transportation equipment industries recovering to 2008 levels in 2011. However, as the recovery continues and increased oil and natural gas production from shale resources begins to affect U.S. competitiveness, growth in U.S. manufacturing output accelerates through 2022.

After 2020, manufacturing output slows because of increased foreign competition and rising energy prices, which weigh most heavily on the energy-intensive industries. The energy-intensive industries grow at a rate of 1.8 percent per year from 2011 to 2020 and 0.6 percent per year from 2020 to 2040. Growth rates within the sector vary by industry, ranging from an annual average of 0.6 percent for bulk chemicals to 2.8 percent for the cement industry.

Export expansion is an important factor for industrial production growth, along with consumer demand and investment. A decline in U.S. dollar exchange rates, combined with modest escalation in unit labor costs, stimulates U.S. exports in the projection. From 2011 to 2040, real exports of goods and services increase by an average of 5.5 percent per year, while real imports of goods and services grow by an average of 3.8 percent per year.

## Energy expenditures decline relative to gross domestic product and gross output

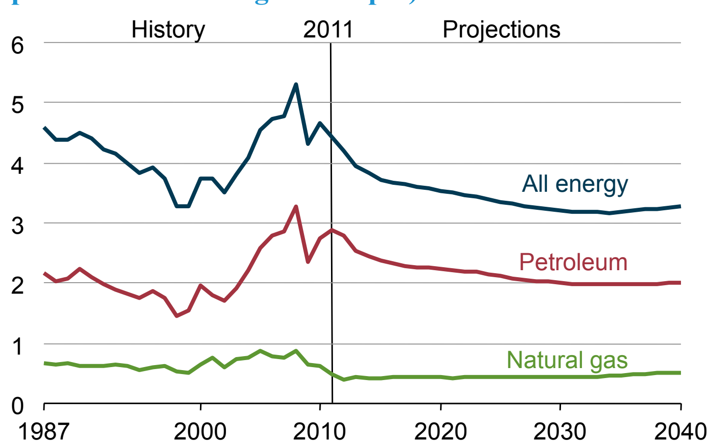
**Figure 47. Energy end-use expenditures as a share of gross domestic product, 1970-2040 (nominal expenditures as percent of nominal GDP)**




Total U.S. energy expenditures decline relative to GDP [*125*] in the *AEO2013* Reference case (Figure 47). The projected ratio of energy expenditures to GDP averages 6.8 percent from 2011 to 2040, which is below the historical average of 8.8 percent from 1970 to 2010.

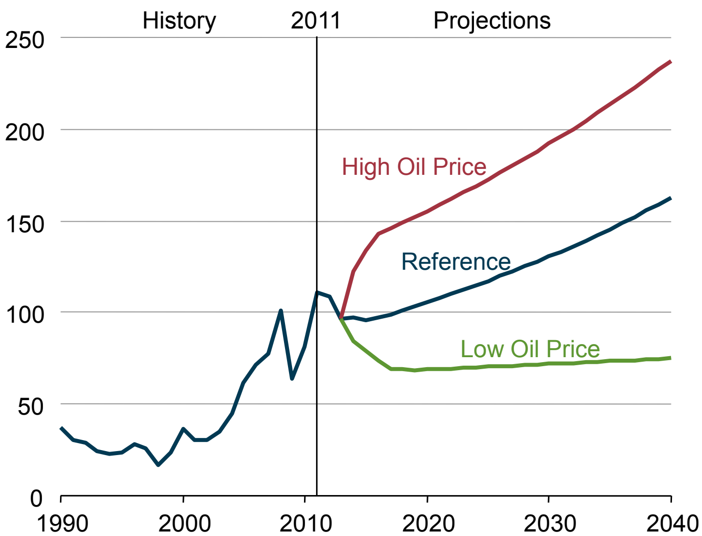
Figure 48 shows nominal energy expenditures relative to U.S. gross output, which roughly correspond to sales in the U.S. economy. Thus, the figure gives an approximation of total energy expenditures relative to total sales. Energy expenditures as a share of gross output show nearly the same pattern as their share of GDP, declining through 2040. The average shares of gross output relative to expenditures for total energy, petroleum, and natural gas, at 3.5 percent, 2.2 percent, and 0.4 percent, are close to their historical averages of 4.2 percent, 2.1 percent, and 0.7 percent, respectively.

**Figure 48. Energy end-use expenditures as a share of gross output, 1987-2040 (nominal expenditures as percent of nominal gross output)**



## Range of oil price cases represents uncertainty in world oil markets

**Figure 49. Brent crude oil spot prices in three cases, 1990-2040 (2011 dollars per barrel)**



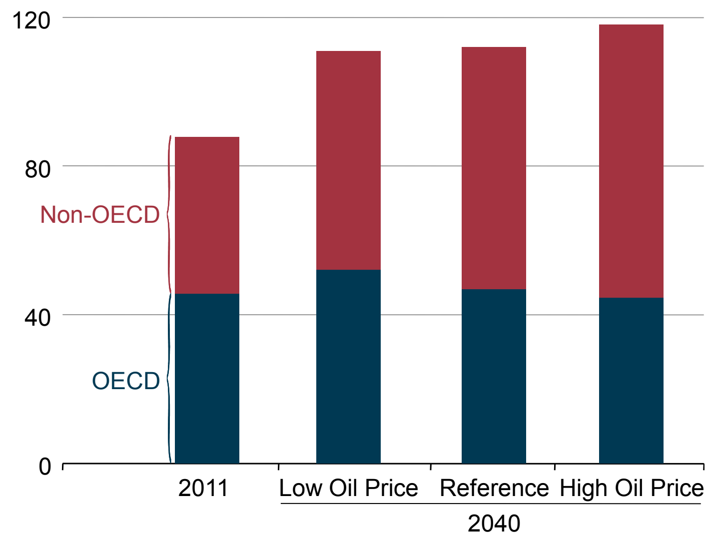

In *AEO2013*, the Brent crude oil price is tracked as the main benchmark for world oil prices. The West Texas Intermediate (WTI) crude oil price has recently been discounted relative to other world benchmark crude prices. The recent growth in U.S. mid-continental oil production has exceeded the capacity of the oil transportation infrastructure out of Cushing, Oklahoma, the market center for WTI prices. The U.S. Energy Information Administration (EIA) expects the WTI price to approach levels near the Brent price as new oil pipeline capacity is added and begins operation.

Future oil prices are uncertain. EIA develops three oil price cases—Reference, High, and Low—to examine how alternative price paths could affect future energy markets (Figure 49). The *AEO2013* price cases were developed by changing assumptions about four key factors: (1) the economics of petroleum liquids supply from countries outside the Organization of the Petroleum Exporting Countries (non-OPEC), (2) OPEC investment and production decisions, (3) the economics of other nonpetroleum liquids supply, and (4) world demand for petroleum and other liquids.

Relative to the Reference case, the Low Oil Price case assumes lower levels of world economic growth and liquid fuels demand, as well as more abundant and less costly non-OPEC liquid fuels supply. In the Low Oil Price case, OPEC supplies 49 percent of the world's liquid fuels in 2040, compared with 43 percent in the Reference case. The High Oil Price case assumes higher levels of world economic growth and liquid fuels demand, along with less abundant and more costly non-OPEC liquid fuels supply. In the High Oil Price case, OPEC supplies 40 percent of the world's liquid fuels in 2040.

## Trends in petroleum and other liquids markets are defined largely by the developing nations

**Figure 50. World petroleum and other liquids consumption by region in three cases, 2011 and 2040 (million barrels per day)**



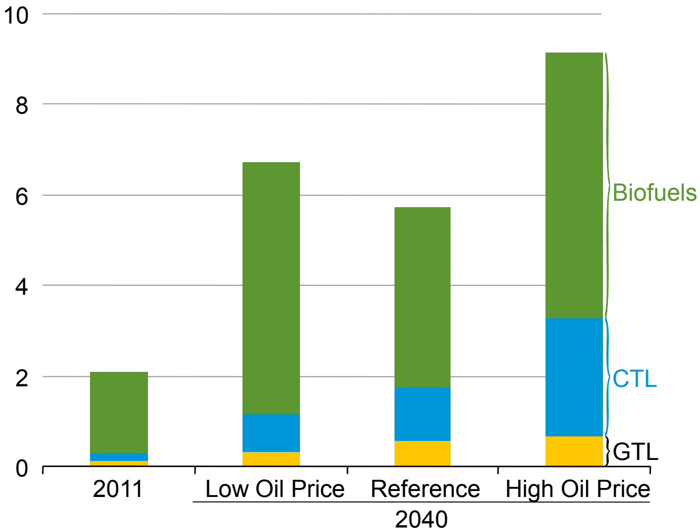

In the *AEO2013* Reference, High Oil Price, and Low Oil Price cases, total world consumption of petroleum and other liquids in 2040 ranges from 111 to 118 million barrels per day (Figure 50). The alternative oil price cases reflect shifts in both supply and demand. Although demand at the margin in the Organization for Economic Cooperation and Development (OECD) countries is influenced primarily by price, demand in non-OECD regions, where future growth in world demand is concentrated, is driven primarily by rates of economic growth that are particularly uncertain. The *AEO2013* Low Oil Price case reflects a scenario where slightly weaker economic growth limits non-OECD oil demand growth.

OECD petroleum and other liquids use grows in the Reference case to 47 million barrels per day in 2040, while non-OECD use grows to 65 million barrels per day. In the Low Oil Price case, OECD petroleum and other liquids use in 2040 is higher than in the Reference case, at 52 million barrels per day, but demand in the slow-growing non-OECD economies rises to only 59 million barrels per day. In the High Oil Price case, OECD consumption grows to 45 million barrels per day in 2040, and fast-growing non-OECD use—driven by higher GDP growth—increases to 73 million barrels per day in 2040.

The supply response also varies across the price cases. In the Low Oil Price case, OPEC's ability to manage its market share is weakened. Low prices have a negative impact on non-OPEC petroleum supply in comparison with the Reference case. In the High Oil Price case, OPEC restricts production, non-OPEC petroleum resources become more economical, and high oil prices make other liquids more economically attractive.

## Production of liquid fuels from biomass, coal, and natural gas increases

**Figure 51. World production of liquids from biomass, coal, and natural gas in three cases, 2011 and 2040 (million barrels per day)**



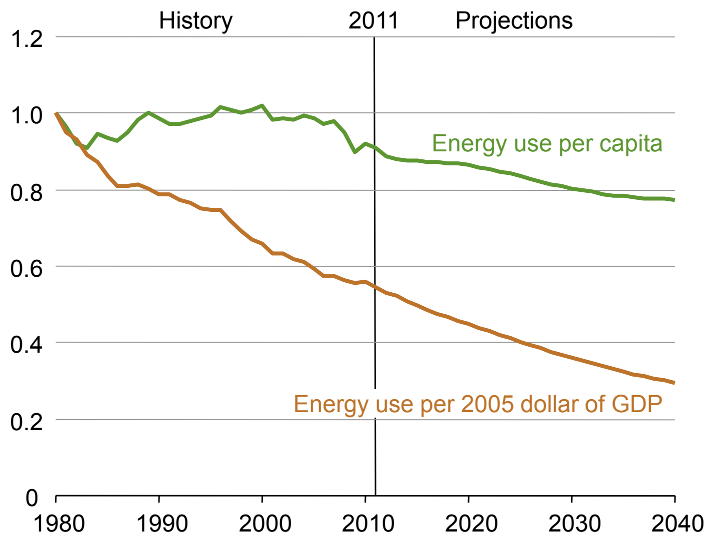

In 2011, world production of liquid fuels from biomass, coal, and natural gas totaled 2.1 million barrels per day, or about 2 percent of the energy supplied by all liquid fuels. In the *AEO2013* Reference case, production from the three sources grows to 5.7 million barrels per day in 2040 (Figure 51), or about 4 percent of the energy supplied by all liquid fuels.

In the Low Oil Price case, production of liquid fuels from these sources grows to 6.7 million barrels per day in 2040, as technology development is faster than projected in the Reference case, making the liquids easier to produce at lower cost, and demand for ethanol for use in existing blend ratios is higher. In the High Oil Price case, production grows to 9.1 million barrels per day in 2040, as higher prices stimulate greater investment in advanced liquid fuels technologies.

Across the three oil price cases, the largest contributions to production of advanced liquid fuels come from U.S. and Brazilian biofuels. In the Reference case, biofuel production totals 4.0 million barrels per day in 2040, and production of gas-to-liquids (GTL) and coal-to-liquids (CTL) fuels accounts for 1.7 million barrels per day of additional production in 2040. Biofuels production in 2040 totals 5.5 million barrels per day in the Low Oil Price case and 5.9 million barrels per day in the High Oil Price case. The projections for CTL and GTL production are more sensitive to world oil prices, varying from 1.2 million barrels per day in the Low Oil Price case to 3.3 million barrels per day in the High Oil Price case in 2040. In the Reference case, the U.S. share of world GTL production in 2040 is 36 percent, as recent developments in domestic shale gas supply have contributed to optimism about the long-term outlook for U.S. GTL plants.

## In the United States, average energy use per person declines from 2011 to 2040

**Figure 52. Energy use per capita and per dollar of gross domestic product, 1980-2040 (index, 1980 = 1)**




Population growth affects energy use through increases in housing, commercial floorspace, transportation, and economic activity. The effects can be mitigated, however, as the structure and efficiency of the U.S. economy change. In the *AEO2013* Reference case, U.S. population increases by 0.9 percent per year from 2011 to 2040; the economy, as measured by GDP, increases at an average annual rate of 2.5 percent; and total energy consumption increases by 0.3 percent per year. As a result, energy intensity, measured both as energy use per person and as energy use per dollar of GDP, declines through the projection period (Figure 52).

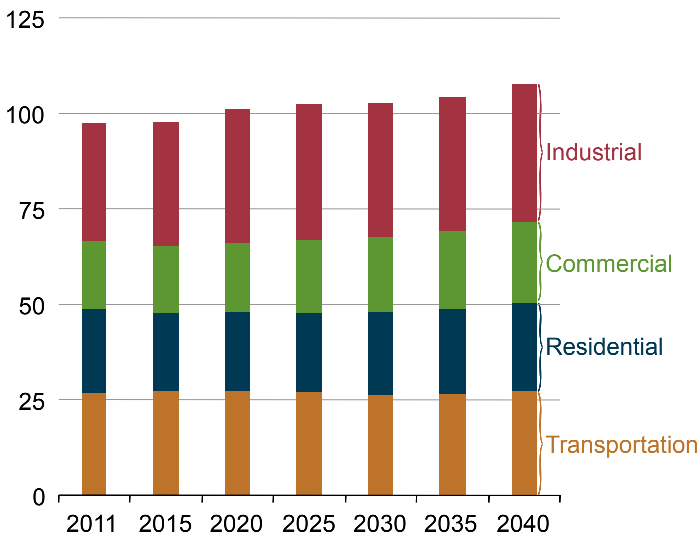
The decline in energy use per capita is brought about largely by gains in appliance efficiency and an increase in vehicle efficiency standards by 2025. From 1970 through 2008, energy use dipped below 320 million Btu per person for only a few years in the early 1980s. In 2011, energy use per capita was about 312 million Btu. In the Reference case, it declines to less than 270 million Btu per person in 2034—a level not seen since 1963.

After some recovery through 2020, the economy continues to shift away from manufacturing (particularly, energy-intensive industries such as iron and steel, aluminum, bulk chemicals, and refineries) toward service industries. The energy-intensive industries, which represented about 5.9 percent of total shipments in 2011, represent 4.4 percent in 2040 in the Reference case. Efficiency gains in the electric power sector also reduce overall energy intensity, as older, less efficient generators are retired as a result of slower growth in electricity demand, changing dispatch economics related to fuel prices and stricter environmental regulations.

# U.S. energy demand

## Industrial and commercial sectors lead U.S. growth in primary energy use

**Figure 53. Primary energy use by end-use sector, 2011-2040 (quadrillion Btu)**




Total primary energy consumption, including fuels used for electricity generation, grows by 0.3 percent per year from 2011 to 2040, to 107.6 quadrillion Btu in 2040 in the *AEO2013* Reference case (Figure 53). The largest growth, 5.1 quadrillion Btu from 2011 to 2040, is in the industrial sector, attributable to increased use of natural gas in some industries (bulk chemicals, for example) as a result of an extended period of relatively low prices coinciding with rising shipments in those industries. The industrial sector was more severely affected than the other end-use sectors by the 2007-2009 economic downturn; the increase in industrial energy consumption from 2008 through 2040 is 3.9 quadrillion Btu.

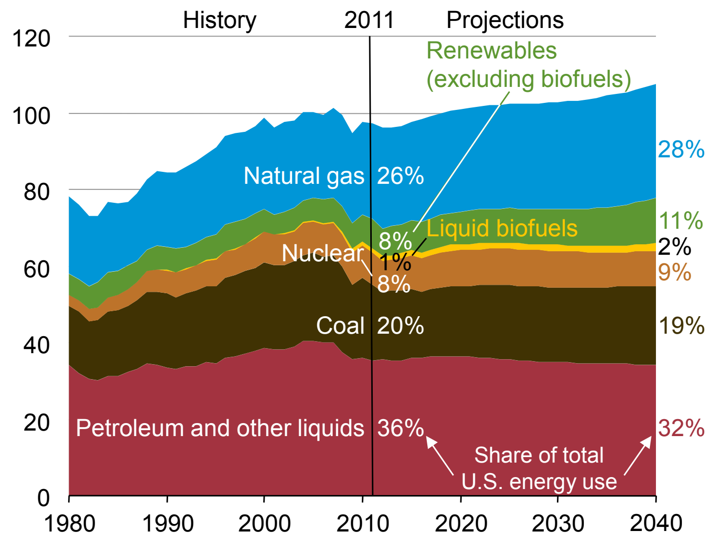
The second-largest increase in total primary energy use, at 3.1 quadrillion Btu from 2011 to 2040, is in the commercial sector, which currently accounts for the smallest share of end-use energy demand. Even as standards for building shells and energy efficiency are being tightened in the commercial sector, the growth rate for commercial energy use, at 0.5 percent per year, is the highest among the end-use sectors, propelled by 1.0-percent average annual growth in commercial floorspace.

Primary energy use in the residential sector grows by 0.2 percent per year, or about 1.6 quadrillion Btu from 2011 to 2040, but it does not increase above the 2011 level until 2029. Increased efficiency reduces energy use for space heating, lighting, and clothes washers.

In the transportation sector, light-duty vehicle (LDV) energy consumption declines as a result of the impact of fuel economy standards through 2025. Total transportation sector energy use is essentially flat from 2011 through 2040, increasing by about 140 trillion Btu.

## Renewables and natural gas lead rise in primary energy consumption

**Figure 54. Primary energy use by fuel, 1980-2040 (quadrillion Btu)**




The aggregate fossil fuel share of total energy use falls from 82 percent in 2011 to 78 percent in 2040 in the Reference case, while renewable use grows rapidly (Figure 54). The renewable share of total energy use (including biofuels) grows from 9 percent in 2011 to 13 percent in 2040 in response to the federal renewable fuels standard; availability of federal tax credits for renewable electricity generation and capacity during the early years of the projection; and state renewable portfolio standard (RPS) programs.

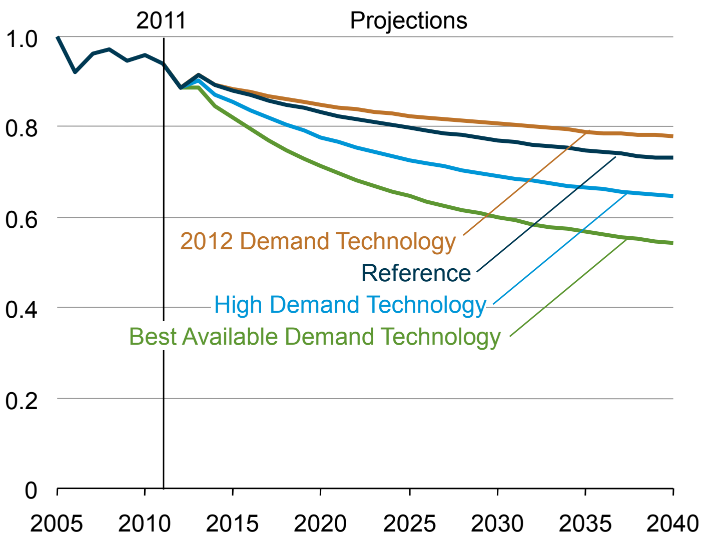
Natural gas consumption grows by about 0.6 percent per year from 2011 to 2040, led by the increased use of natural gas in electricity generation and, at least through 2020, the industrial sector. Growing production from tight shale keeps natural gas prices below their 2005-2008 levels through 2036. In the *AEO2013* Reference case, the amount of liquid fuels made from natural gas (360 trillion Btu) is about three times the amount made from coal.

Increased vehicle fuel economy offsets growth in transportation activity, resulting in a decline in the petroleum and other liquids share of fuel use even as consumption of liquid biofuels increases. Biofuels, including biodiesel blended into diesel, E85, and ethanol blended into motor gasoline (up to 15 percent), account for 6 percent of all petroleum and other liquids consumption by energy content in 2040.

Coal consumption increases at an average rate of 0.1 percent per year from 2011 to 2040, remaining below 2011 levels until 2030. By the end of 2015, a total of 6.1 gigawatts of coal-fired power plant capacity currently under construction comes on line, and another 1.5 gigawatts is added after 2016 in the Reference case, including 0.9 gigawatts with carbon sequestration capability. Additional coal is consumed in the CTL process and to produce heat and power (including electricity generation at CTL plants).

## Residential energy intensity continues to decline across a range of technology assumptions

**Figure 55. Residential delivered energy intensity in four cases, 2005-2040 (index, 2005 = 1)**



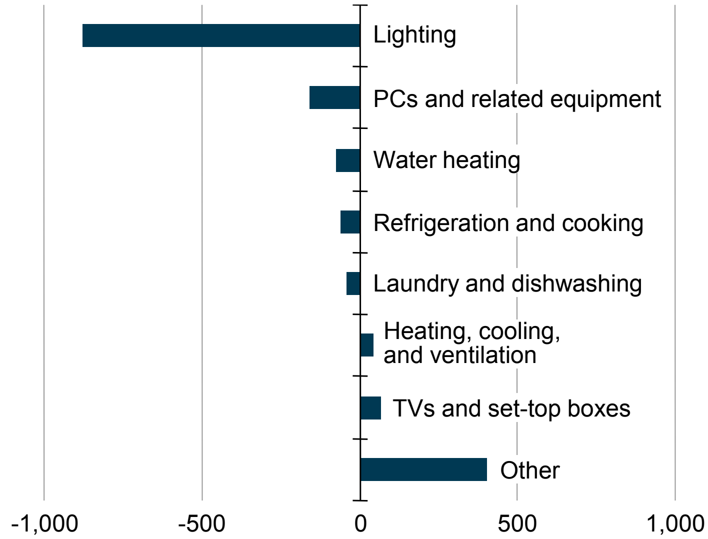

In the *AEO2013* Reference case, the energy intensity of residential demand, defined as annual energy use per household, declines from 97.2 million Btu in 2011 to 75.5 million Btu in 2040 (Figure 55). The projected 22-percent decrease in intensity occurs along with a 32-percent increase in the number of homes. Residential energy intensity is affected by various factors—for example, population shifts to warmer and drier climates, improvements in the efficiency of building construction and equipment stock, and the attitudes and behavior of residents toward energy savings.

Three alternative cases show the effects of different technology assumptions on residential energy intensity. The 2012 Demand Technology case assumes no future improvement in efficiency for equipment or building shells beyond what is available in 2012. The High Demand Technology case assumes higher efficiency, earlier availability, lower cost, and more frequent energy-efficient purchases for some equipment. The Best Available Demand Technology case limits customer purchases of new and replacement equipment to the most efficient models available at the time of purchase—regardless of cost. This case also assumes that new homes are constructed to the most energy-efficient specifications.

From 2011 to 2040, household energy intensity declines by 31 percent in the High Demand Technology case and by 42 percent in the Best Available Demand Technology case. In the 2012 Demand Technology case, energy intensity is slightly higher than in the Reference case but still declines by 17 percent from 2011 to 2040 as a result of the replacement of pre-2012 appliance stocks with 2012 vintage equipment.

## Electricity use per household declines from 2011 to 2040 in the Reference case

**Figure 56. Change in residential electricity consumption for selected end uses in the Reference case, 2011-2040 (kilowatthours per household)**




Average electricity demand per household declines by 6 percent in the Reference case, from 12.3 megawatthours in 2011 to 11.5 megawatthours in 2040. As the number of households grows, however, total delivered electricity consumption in the residential sector increases by about 24 percent. Over the same period, residential use of natural gas falls by 12 percent, and use of petroleum and other liquids falls by 25 percent. Total energy demand for most electric end uses increases, even as it declines on a per-household basis. In 2040, space cooling and "other uses" consume 42 percent and 52 percent more electricity, respectively, than in 2011 and remain the largest residential uses of electricity. Electricity use for personal computers (PCs) and related equipment and for clothes washers declines.

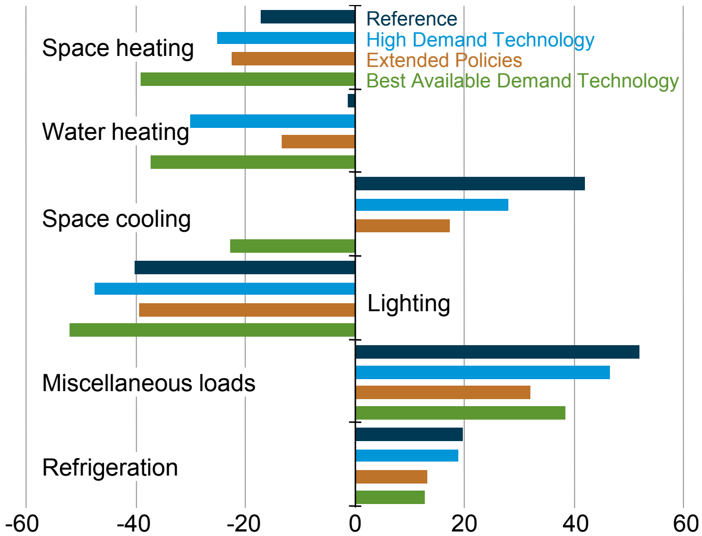
The largest reduction in residential electricity use is for lighting (Figure 56). The Energy Independence and Security Act of 2007 (EISA2007) phases in standards that require a reduction of about 30 percent in energy use for general-service lamps between 2012 and 2014, with specific dates that vary by light level. On January 1, 2013, the requirements went into effect for 75-watt incandescent bulbs; the requirements for 100-watt incandescent bulbs went into effect a year earlier. The EISA2007 standards result in the replacement of incandescent bulbs with more efficient compact fluorescent lighting and light-emitting diode (LED) lamps.

Among electric end-use services in the residential sector, lighting demand declines at the fastest rate (1.8 percent per year) and "other uses" rise at the fastest rate (1.4 percent per year). The growth in other uses stems from the introduction of new electrical devices in households, with little coverage by efficiency standards. Electricity use for water heating also increases, but at a slower rate (0.7 percent per year) than the growth in number of households (1.0 percent per year).

# Residential sector energy demand

## Efficiency can offset increases in residential service demand

**Figure 57. Change in residential delivered energy consumption for selected end uses in four cases, 2011-2040 (percent)**



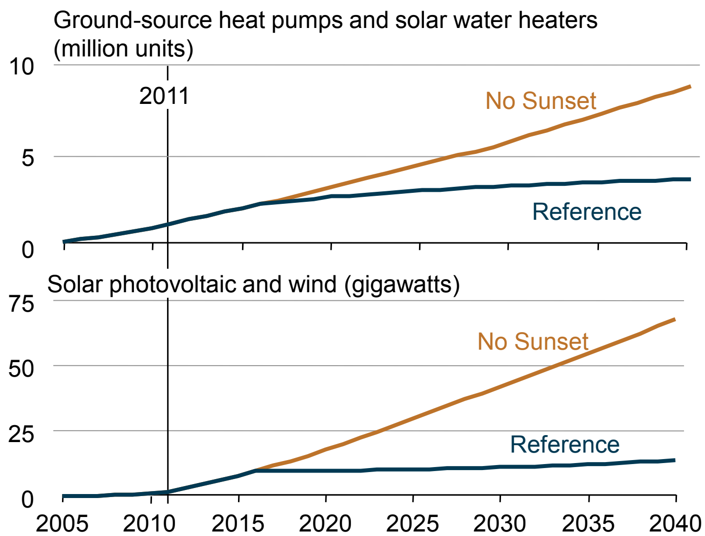

The number of households increases by 32 percent, and total residential square footage increases by 41 percent from 2011 to 2040 in the *AEO2013* Reference case. Without efficiency improvements, energy demand for uses such as heating, cooling, and lighting would increase at similar rates; however, for many end uses, delivered energy consumption increases more slowly or, in some instances, declines in the Reference case. Three alternative cases show how efficiency improvements could affect energy consumption levels (Figure 57). The High Demand Technology and Best Available Demand Technology cases assume different levels of efficiency improvement without anticipating new appliance standards. The Extended Policies case assumes the enactment of new rounds of standards, generally based on improvements seen in current ENERGY STAR equipment.

Energy consumption declines in the Reference case for two major end uses, space heating and water heating. Energy use for space cooling in the Reference case grows by 42 percent from 2011 to 2040—faster than the number of households, reflecting both population shifts and changes in the number of degree days. In the Best Available Demand Technology case, which includes greater adoption of efficient space cooling equipment, energy use for space cooling declines over the same period.

In all four cases, substantial declines in energy use for lighting reflect EISA2007 efficiency standards. For the category of miscellaneous loads—a wide range of small appliances and electronics, most of which are not currently subject to efficiency standards—delivered energy use increases at the same rate as the number of households in the Extended Policies case (32 percent from 2011 to 2040) and more rapidly than the number of households in the Reference, High Demand Technology, and Best Available Demand Technology cases because of more limited efficiency improvement.

## Planned expiration of tax credits affects renewable energy use in the residential sector

**Figure 58. Residential sector adoption of renewable energy technologies in two cases, 2005-2040**



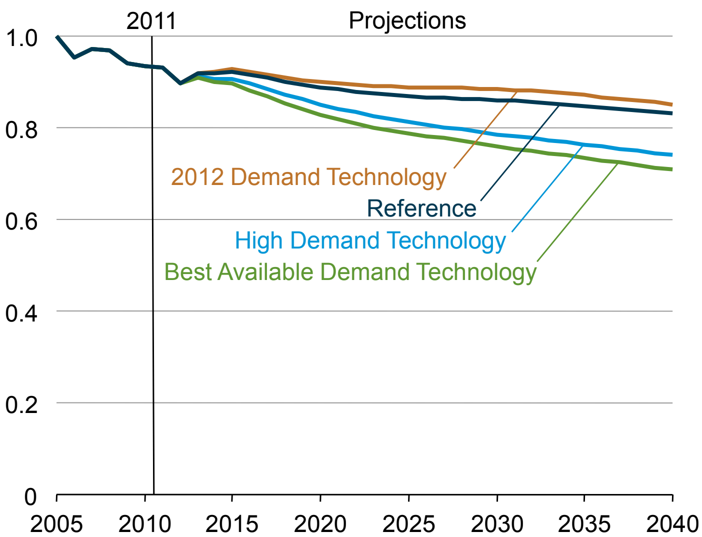

Consistent with current law, existing investment tax credits (ITCs) for residential households installing renewable energy technologies expire at the end of 2016 in the *AEO2013* Reference case. The credits can offset 30 percent of installed costs for a variety of technologies, including solar photovoltaic (PV) and wind generators, ground-source heat pumps, and solar thermal water heaters. In the Reference case, expiration of the ITCs drastically slows adoption of renewable technologies. In the *AEO2013* No Sunset case, the ITCs are extended through 2040, and the adoption of renewable technologies continues to rise (Figure 58).

In the Reference case, combined PV and wind capacity in the residential sector grows from 1.1 gigawatts in 2011 to 9.5 gigawatts in 2016. After 2016, expiration of the ITCs results in slower growth, with an additional 4.1 gigawatts added from 2017 through 2040. In the No Sunset case, more than 58 gigawatts of residential PV and wind capacity is added over the same period. In all cases, the majority of the added capacity is solar PV rather than wind.

Expiration of the ITCs also affects the penetration of renewable space-conditioning and water-heating equipment. With a 30-percent tax credit available, the number of ground-source heat pumps and solar water heaters grows from a combined 1.3 million units in 2011 to 2.4 million units in 2016; but after 2016 only 1.4 million additional units are added through 2040 in the Reference case. Even in the more optimistic No Sunset case, however, the two renewable technologies are adopted in only a small percentage of households—fewer than 6 percent—by 2040. In the No Sunset case, with the ITC extended, 6.4 million additional units are installed after 2016.

## For commercial buildings, pace of decline in energy intensity depends on technology

**Figure 59. Commercial delivered energy intensity in four cases, 2005-2040 (index, 2005 = 1)**



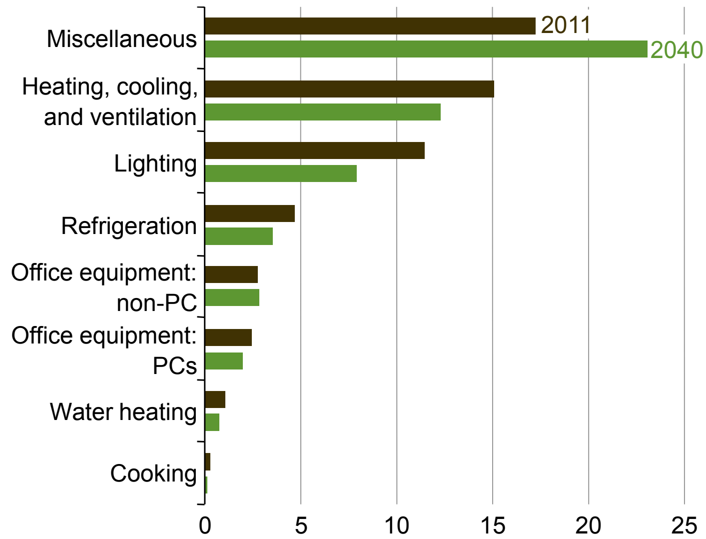

Average delivered energy consumption per square foot of commercial floorspace declines at an annual rate of 0.4 percent from 2011 to 2040 in the *AEO2013* Reference case (Figure 59), while commercial floorspace grows by 1.0 percent per year. Natural gas consumption increases at about one-half the rate of delivered electricity consumption, which grows by 0.8 percent per year in the Reference case. With ongoing improvements in equipment efficiency and building shells, the growth of energy consumption declines more rapidly than commercial floorspace increases, and the average energy intensity of commercial buildings is reduced.

Three alternative technology cases show the effects of efficiency improvements on commercial energy consumption. The 2012 Demand Technology case limits equipment and building shell efficiencies in later years to those available in 2012. The High Demand Technology case assumes earlier availability, lower costs, and higher efficiencies for equipment and building shells, and a 7-percent real discount rate for energy efficiency investments. The Best Available Demand Technology case assumes more efficient building shells for new and existing buildings than in the High Demand Technology case and limits replacement of new equipment to the most efficient models available in any given year.

The intensity of commercial energy use in the Reference case declines by 10.8 percent, from 105.2 thousand Btu per square foot in 2011 to 93.8 thousand Btu per square foot in 2040. By comparison, average commercial energy intensity drops by about 8.6 percent in the 2012 Demand Technology case, to 96.1 thousand Btu per square foot in 2040, by 20.5 percent in the High Demand Technology, and by 23.9 percent in the Best Available Demand Technology case.

## Greatest reduction in energy intensity is in commercial lighting

**Figure 60. Energy intensity of selected commercial electric end uses, 2011 and 2040 (thousand Btu per square foot)**




Commercial energy intensity, defined as the ratio of energy consumption to floorspace, decreases for most electric end uses from 2011 to 2040 in the *AEO2013* Reference case (Figure 60). In 2011, electricity accounted for 52.4 percent of total commercial delivered energy use. Through the projection period, electricity use for lighting declines as a portion of total energy consumption in the Reference case. Advances in solid-state lighting technologies yield lamps with higher efficacy and lower cost, as well as products that can replace, or be retrofitted into, a wide variety of fixture types. As a result, the share of purchased electricity consumption used for lighting declines from 20.8 percent in 2011 to 15.1 percent in 2040 in the Reference case.

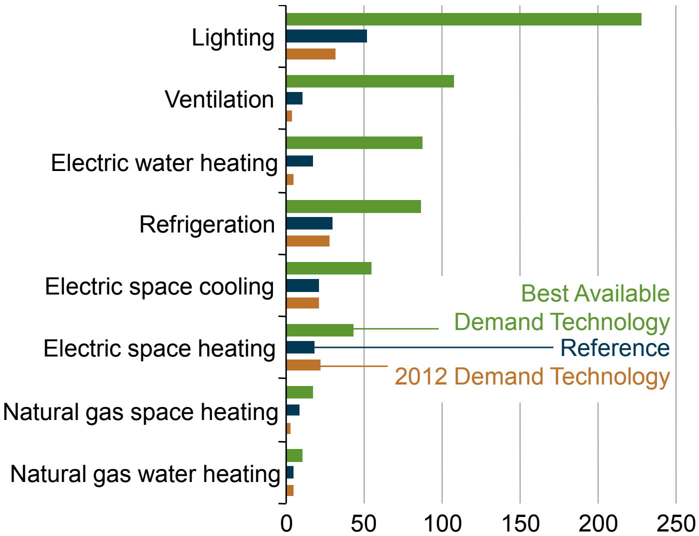
Commercial floorspace grows by an average of 1.0 percent per year from 2011 to 2040. Federal efficiency standards, which help to foster technological improvements in end uses such as space heating and cooling, water heating, refrigeration, and lighting, act to limit growth in energy consumption to less than the growth in commercial floorspace. Increasing energy use for miscellaneous electric loads, many of which currently are not subject to federal standards, leads to a 33.9-percent increase in energy intensity from 2011 to 2040 for "other" end uses in the Reference case. Miscellaneous electric loads in the commercial sector include medical equipment and video displays, among many other devices.

Although the recent recession slowed the rate of installation of new data centers, growing demand for web-based services continues to drive growth in energy use for non-PC office equipment, which increases by an average of 1.1 percent per year from 2011 to 2040. Improvements in data center cooling and ventilation equipment, as well as increased server efficiency, continue to moderate the increase.

# Commercial sector energy demand

## Efficiency gains for advanced technologies reduce commercial energy consumption growth

**Figure 61. Efficiency gains for selected commercial equipment in three cases, 2040 (percent change from 2011 installed stock efficiency)**



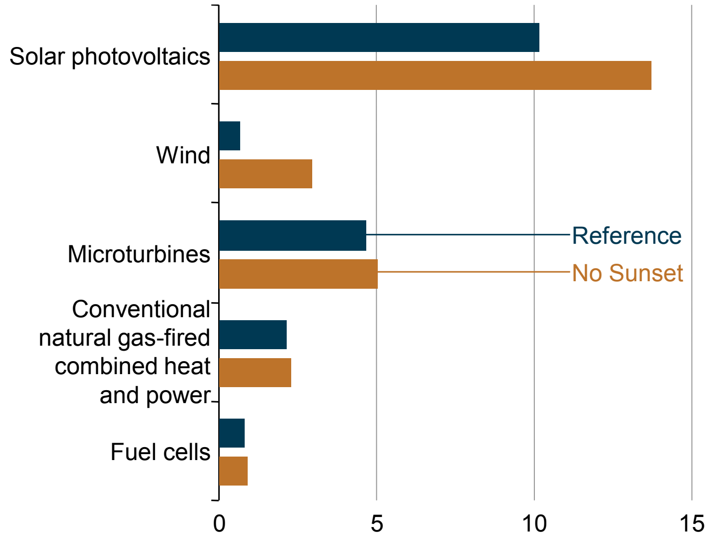

In the *AEO2013* Reference case, delivered energy use for core commercial end uses (space heating, space cooling, ventilation, water heating, lighting, cooking, and refrigeration) falls by an average of 0.1 percent per year from 2011 to 2040, even as commercial floorspace increases by 1 percent annually. The share of commercial delivered energy consumption accounted for by the core end uses, which have been the focus of a number of energy efficiency standards, falls from 60 percent in 2011 to 50 percent in 2040. Energy consumption for the remaining end uses grows by 1.4 percent per year, led by other uses of electricity and by non-PC office equipment, including servers.

The largest efficiency gains in the Reference case are expected for lighting as a result of updated cost projections for advanced LED technologies, especially after 2030. Significant gains also are projected for refrigeration, based on provisions in the Energy Policy Act of 2005 and EISA2007, space cooling, electric space heating, and electric water heating (Figure 61).

The Best Available Demand Technology case demonstrates significant potential for further improvements—especially in electric equipment. In this case, the core end uses account for only 43 percent of total delivered energy use in 2040, when their total delivered energy use is more than 1 quadrillion Btu lower than projected in the Reference case. More than 30 percent of the reduction in demand is attributed to lighting, followed by ventilation and space heating. Additional efficiency gains for commercial lighting arise from earlier and more widespread penetration of LED technologies. Other notable contributions result from high-efficiency versions of variable air volume ventilation systems and chillers for space cooling. Overall, delivered energy consumption in 2040 in the Best Available Demand Technology case is only 0.1 quadrillion Btu higher than in 2011, despite a 33-percent increase in commercial floorspace.

## Renewable energy fuels most additions to commercial distributed generation capacity

**Figure 62. Additions to electricity generation capacity in the commercial sector in two cases, 2011-2040 (gigawatts)**



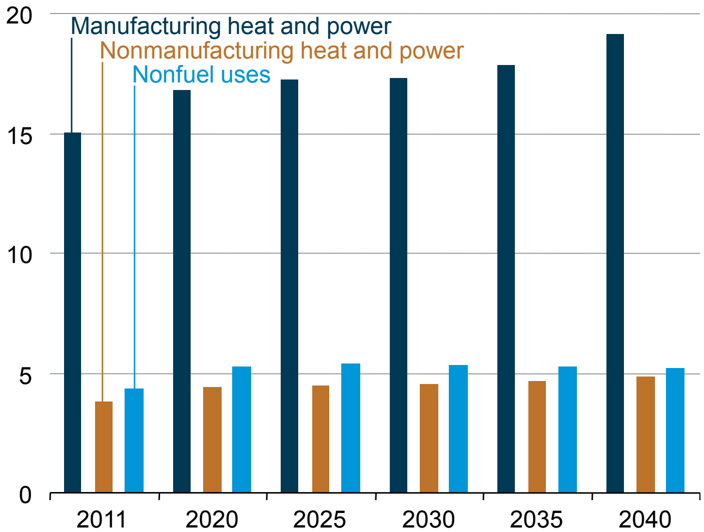

PV and wind account for 58.7 percent of commercial distributed generation capacity in 2040 in the *AEO2013* Reference case. Exponential growth of PV capacity has occurred in both new and existing construction during recent years as a result of utility incentives, new financing options, and the 30-percent federal ITC that reverts to 10 percent in 2017. In the Reference case, commercial PV capacity increases by 6.5 percent annually from 2011 to 2040. In the No Sunset case, with ITCs for all distributed generation technologies extended through 2040, PV capacity increases by an average of 7.4 percent per year.

Small-scale wind capacity increases by 7.4 percent per year from 2011 to 2040 in the Reference case and by an even greater 12.6 percent per year from 2011 to 2040 in the No Sunset case (Figure 62). As with PV, additional federal and local incentives help to drive growth in commercial wind capacity. Wind capacity accounts for 10.7 percent of the 28.4 gigawatts of total distributed generation capacity in 2040 in the No Sunset case, and PV accounts for 55.2 percent.

Rising fuel prices offset the effects of the 10-percent ITC on nonrenewable technologies for distributed generation. In the Reference case, microturbine capacity using natural gas grows by 15.0 percent per year on average, from 83.3 megawatts in 2011 to 4.7 gigawatts in 2040; and the growth rate in the No Sunset case is only slightly higher, at 15.3 percent. The microturbine share of total DG capacity in 2040 is 18.0 percent in the No Sunset case, as compared with 21.6 percent in the Reference case, and fuel cell capacity grows at an annual rate of roughly 10.9 percent in the Reference case and 11.3 percent in the No Sunset case.

## Growth in industrial energy consumption is slower than growth in shipments

**Figure 63. Industrial delivered energy consumption by application, 2011-2040 (quadrillion Btu)**



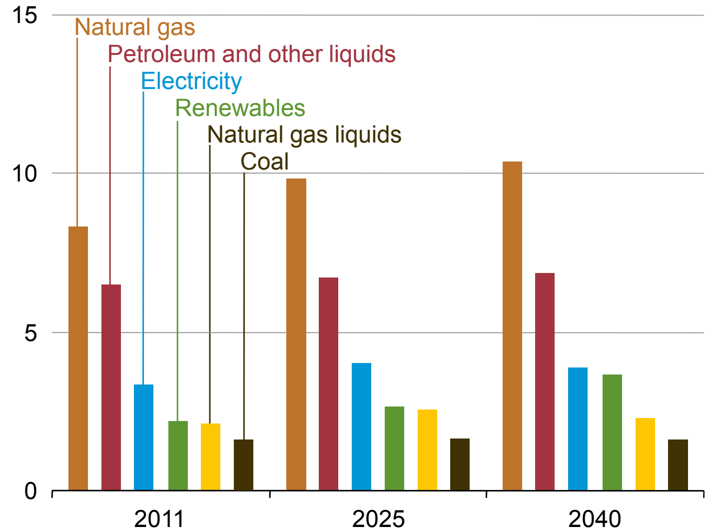

Despite a 76-percent increase in industrial shipments, industrial delivered energy consumption increases by only 19 percent from 2011 to 2040 in the *AEO2013* Reference case. The continued decline in energy intensity of the industrial sector is explained in part by a shift in the share of shipments from energy-intensive manufacturing industries (bulk chemicals, petroleum refineries, paper products, iron and steel, food products, aluminum, cement and lime, and glass) to other, less energy-intensive industries, such as plastics, computers, and transportation equipment. Also, the decline in energy intensity for the less energy-intensive industries is almost twice that for the more energy-intensive industries.

Industrial energy consumption increases by 4.7 quadrillion Btu from 2011 to 2040 in the Reference case (Figure 63), or by an average of 0.6 percent per year. Most of the growth occurs in the near term, from 2011 to 2025, with an average yearly increase of 1 percent. After 2025, the annualized rate of increase is 0.3 percent. The share of industrial delivered energy consumption used for heat and power in manufacturing increases modestly, from 63 percent in 2011 to 67 percent in 2040.

Energy consumption for heat and power in the nonmanufacturing industries (agriculture, mining, and construction) increases by about 1.1 quadrillion Btu from 2011 to 2040 in the Reference case, but its percentage of total industrial energy consumption remains at about 16 percent. Nonfuel uses of energy (feedstocks for chemical manufacturing and asphalt for construction) increase by 1.6 percent per year from 2011 to 2025 and decrease by 0.3 percent per year after 2025. The nonfuel share of energy consumption is between 18 and 20 percent over the projection period.

## Reliance on natural gas, natural gas liquids, and renewables rises as industrial energy use grows

**Figure 64. Industrial energy consumption by fuel, 2011, 2025, and 2040 (quadrillion Btu)**



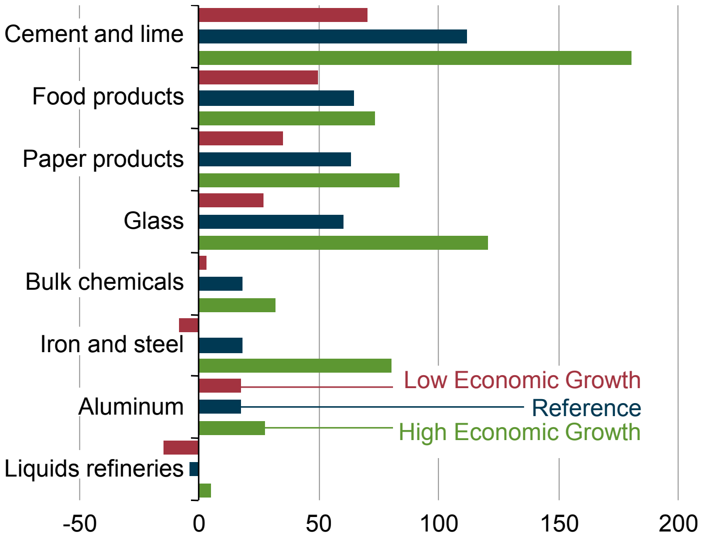

Much of the growth in industrial energy consumption in the *AEO2013* Reference case is accounted for by natural gas use, which increases by 18 percent from 2011 and 2025 and by 6 percent from 2025 to 2040 (Figure 64). With domestic natural gas production increasing sharply in the projection, natural gas prices remain relatively low. The mix of industrial fuels changes relatively slowly, however, reflecting limited capability for fuel switching in most industries.

Consumption of renewable fuels in the industrial sector grows by 22 percent from 2011 to 2025 in the Reference case and by 37 percent from 2025 to 2040. The paper industry remains the predominant consumer of renewable energy (mostly biomass) in the industrial sector. Industrial consumption of natural gas liquids (NGL) increases by 21 percent from 2011 to 2025, followed by a 9-percent decline from 2025 to 2040. NGL are consumed predominantly as feedstocks in the bulk chemicals industry and for process heat in other industries. NGL use declines starting in 2025 as shipments of bulk chemicals begin to decline in the face of increased international competition. Industrial coal use drops by less than 1 percent from 2011 to 2040, and the use of petroleum and other liquid fuels increases by 6 percent.

Low natural gas prices and increased availability of biomass contribute to growth in the use of combined heat and power (CHP). A small decline in the purchased electricity share of industrial energy consumption (less than 1 percent from 2011 to 2040) reflects growth in CHP, as well as efficiency improvements resulting from rising standards for electric motors.

## Iron and steel, cement, and glass industries are most sensitive to the economic growth rate

**Figure 65. Cumulative growth in value of shipments from energy-intensive industries in three cases, 2011-2040 (percent)**



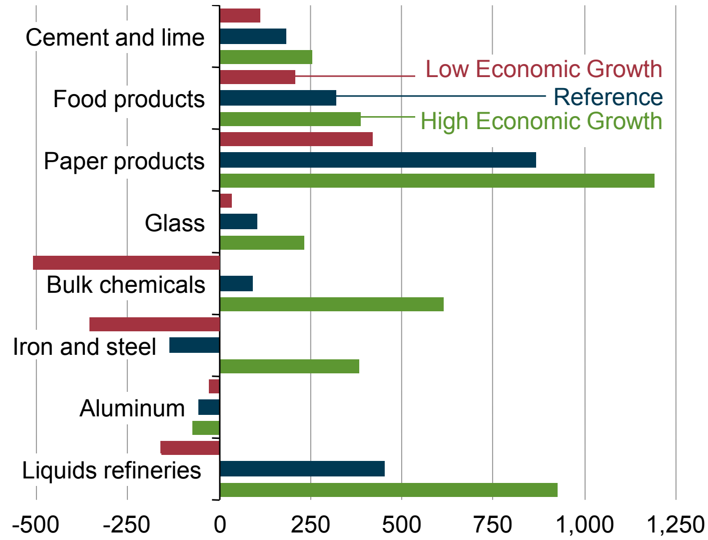

Total shipments from the energy-intensive industries grow by an average of 1.0 percent per year from 2011 to 2040 in the *AEO2013* Reference case, as compared with 0.6 percent in the Low Economic Growth case and 1.4 percent in the High Economic Growth case. Growth in shipments is uneven among the industrial subsectors.

The iron and steel, cement, and glass industries show the greatest variability in shipments across the three cases, because they supply downstream industries that are sensitive to investment, which is more variable than GDP. Construction is a downstream user of the output for all three industries, and the metal-based durables sector is a downstream industry for the iron and steel and glass industries. The high rate of shipments growth for those industries is related largely to recovery from the recent recession. Shipments of paper products grow steadily in each of the three cases (Figure 65).

The food, bulk chemicals, and aluminum industries show less variability among the three cases. Food shipments, which tend to grow in proportion to population, are less sensitive to investment. The bulk chemicals and aluminum industries face significant international competition, but they experience significant growth, largely related to relatively inexpensive natural gas and associated declines in electricity costs for aluminum manufacturers. Shipments from the petroleum refineries industry either decline or grow relatively slowly in each of the three cases as a result of slow growth in demand for petroleum-based fuels.

## Energy use reflects output and efficiency trends in energy-intensive industries

**Figure 66. Change in delivered energy consumption for energy-intensive industries in three cases, 2011-2040 (trillion Btu)**



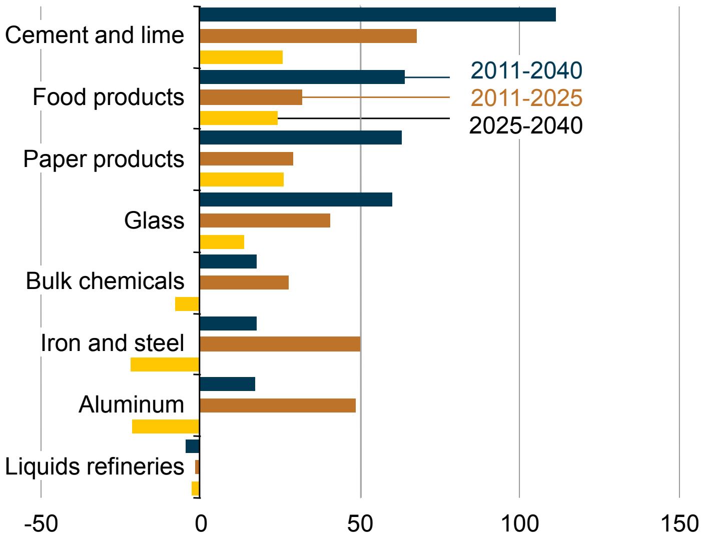

Energy consumption growth in the energy-intensive industries from 2011 to 2040 ranges from no significant change in the Low Economic Growth case to an increase of 3.9 quadrillion Btu in the High Economic Growth case (Figure 66). Energy efficiency improvements reduce the rate of growth in energy consumption relative to shipments. In the *AEO2013* Reference case, energy use in the energy-intensive industries increases by 13 percent, while shipments increase by 33 percent. In the Low Economic Growth case, energy use in the energy-intensive industries declines by 2 percent while shipments increase by 17 percent. In the High Economic Growth case, energy use grows by 27 percent and shipments by 48 percent.

Shipments from all industries grow in the Reference case, but the impact on energy consumption varies by industry because of structural changes and differences in the rate of energy efficiency improvement by industry. For example, shipments from the aluminum industry and the iron and steel industry increase in the projection, even as energy use declines. For the aluminum industry, shipments grow by 17 percent while energy use declines by 16 percent because of a rise in less energy-intensive secondary production. For the iron and steel industry, shipments grow by 18 percent while energy use declines by 10 percent because of a shift from the use of blast furnace steel production to the use of recycled products and electric arc furnaces.

Refining is the only industry subsector that shows an increase in energy intensity. Shipments from refineries fluctuate in the early years and then decline slightly after 2019, with a 4-percent decline in shipments overall from 2011 to 2040. In contrast, energy use for refining increases by 13 percent over the same period, as CTL production and the use of heavy crude feedstock, both of which are more energy-intensive to process than typical crude oil, increase after 2022.

## Most of the growth in shipments from energy-intensive industries occurs before 2025

### Figure 67. Cumulative growth in value of shipments from energy-intensive industries, 2011-2040, 2011-2025, and 2025-2040 (percent)



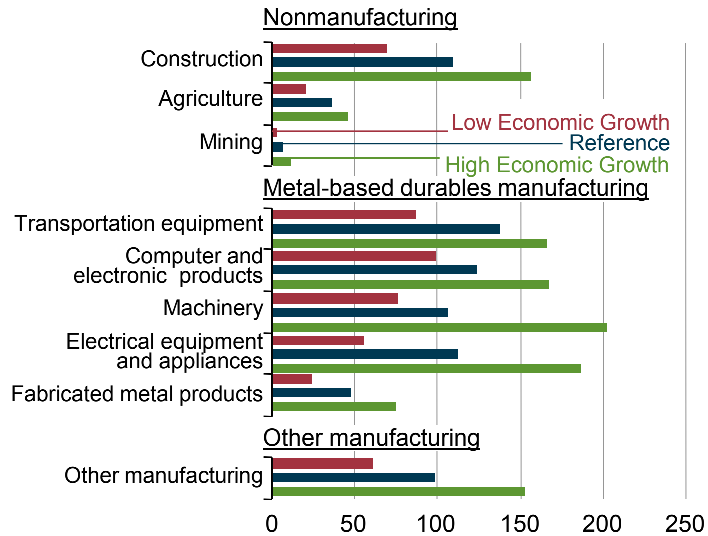

Most of the growth in shipments from energy-intensive industries from 2011 to 2040 occurs before 2025 in the Reference case (Figure 67). The strong growth in the earlier period can be explained largely by low natural gas prices that result from increased domestic production of natural gas from tight formations, as well as continued economic recovery. After 2025 the growth in shipments is weaker, with declines in some industries as a result of growing international competition and rising natural gas prices.

In the bulk chemical industry, shipments grow by 27 percent from 2011 to 2025, then decline by 8 percent from 2025 to 2040. Aluminum shipments and iron and steel shipments both grow by about 50 percent more than shipments of bulk chemicals from 2011 to 2025. The decline in aluminum and iron and steel shipments after 2025, just over 20 percent, is also greater than the decline in bulk chemicals shipments. In addition to growing international competition, the growth in industries downstream from the primary metals sector, such as construction and transportation equipment, weakens after 2025.

The cement and lime and glass industries show continued growth over the period from 2025 to 2040, but at relatively low levels. Cement and lime and glass have high shipping costs, which give domestic suppliers an advantage over imports and help to maintain the sector's growth after 2025. Shipments from the refinery industry show modest declines in both the 2011-2025 and 2025-2040 periods, as demand for transportation fuels is moderated by increasing vehicle efficiencies. The food and paper products industries show the least variation in shipment growth over the projection period, with growth rates declining modestly after 2025.

## Metal-based durable goods show the fastest growth among non-energy-intensive industries

### Figure 68. Cumulative growth in value of shipments from non-energy-intensive industries in three cases, 2011-2040 (percent)



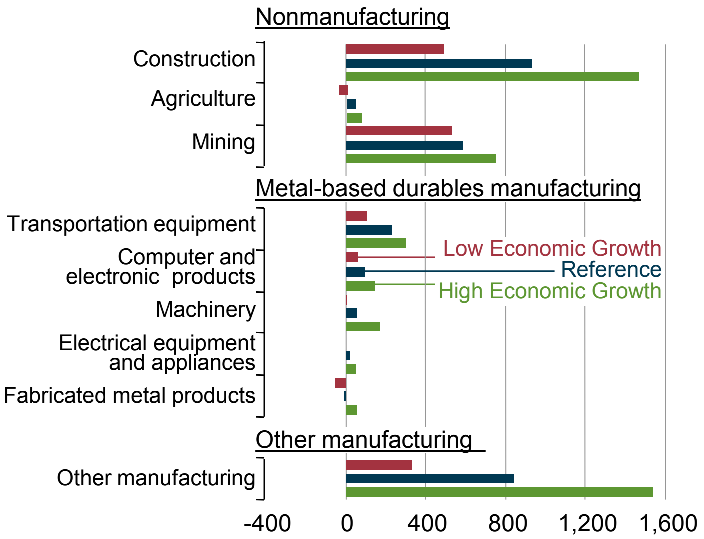

In 2040, the non-energy-intensive manufacturing and nonmanufacturing industrial subsectors account for $8.5 trillion (2005 dollars) in shipments in the *AEO2013* Reference case—a 92-percent increase from 2011. The growth in those shipments from 2011 to 2040 averages 1.6 percent per year in the Low Economic Growth case and 3.0 percent per year in the High Economic Growth case, compared with 2.3 percent in the Reference case (Figure 68). Non-energy-intensive manufacturing and nonmanufacturing are segments of the industrial sector that consume fuels primarily for thermal or electrical needs, not as raw materials or feedstocks.

In the three cases, the annual rate of increase in shipments from non-energy-intensive industries generally is twice the rate of increase for the energy-intensive industries, primarily as a result of growing demand for high-technology, high-value goods. Further, the growth in shipments is fastest in the medium term. From 2011 to 2025, shipments of metal-based durables grow by an average of 3.2 percent per year; from 2025 to 2040, the growth rate slows to 2.1 percent per year.

In the Reference case, shipments from the non-energy-intensive industries grow at different rates. For metal-based durables, shipments grow by 2.6 percent per year from 2011 to 2040, led by 3.0-percent average annual growth for transportation equipment. In the nonmanufacturing sector, construction grows by an average of 2.6 percent per year, agriculture grows by 1.0 percent per year, and mining grows by 0.2 percent per year.

## Nonmanufacturing efficiency gains are slowed by rising energy intensity in the mining industry

### Figure 69. Change in delivered energy consumption for non-energy-intensive industries in three cases, 2011-2040 (trillion Btu)



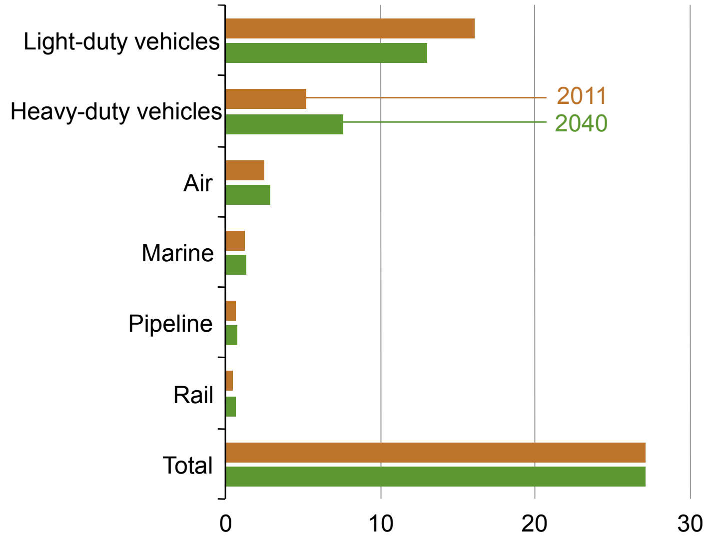

From 2011 to 2040, total energy consumption in the non-energy-intensive manufacturing and nonmanufacturing industrial subsectors increases by 18 percent (1.4 quadrillion Btu) in the Low Economic Growth case, 36 percent (2.8 quadrillion Btu) in the Reference case, and 58 percent (4.6 quadrillion Btu) in the High Economic Growth case (Figure 69).

The nonmanufacturing subsector (construction, agriculture, and mining) accounts for roughly 57 percent of the energy consumed in the non-energy-intensive industries but only 31 percent of the total shipments in 2040. The nonmanufacturing industries are more energy-intensive than the manufacturing industries, and there is no significant decline in energy intensity for the nonmanufacturing industries over the projection period. Construction and agriculture show annual declines in energy intensity from 2011 to 2040 (1.0 percent and 0.9 percent per year, respectively), whereas the energy intensity of the mining industry increased by 0.7 percent from 2011 to 2040 in the *AEO2013* Reference case. Within the nonmanufacturing sector, the mining industry accounts for 17.3 percent of shipments in 2040 and roughly 43.2 percent of the energy consumed, as the energy intensity of mining activity increases with resource depletion over time.

In comparison, the non-energy-intensive manufacturing industries—such as plastics, computers, and transportation equipment—show a 33-percent decline in energy intensity from 2011 to 2040, or an average decline of about 1.4 percent per year. For the transportation equipment industry, which accounts for 19 percent of the increase in energy use but roughly 29 percent of the increase in shipments, energy intensity declines by 1.5 percent per year on average in the Reference case.

## Growth in transportation energy consumption flat across projection

### Figure 70. Delivered energy consumption for transportation by mode, 2011 and 2040 (quadrillion Btu)




The transportation sector consumes 27.1 quadrillion Btu of energy in 2040, the same as the level of energy demand in 2011 (Figure 70). The projection of no growth in transportation energy demand differs markedly from the historical trend, which saw 1.1-percent average annual growth from 1975 to 2011 [*126*]. No growth in transportation energy demand is the result of declining energy use for LDVs, which offsets increased energy use for heavy-duty vehicles (HDVs), aircraft, marine, rail, and pipelines.

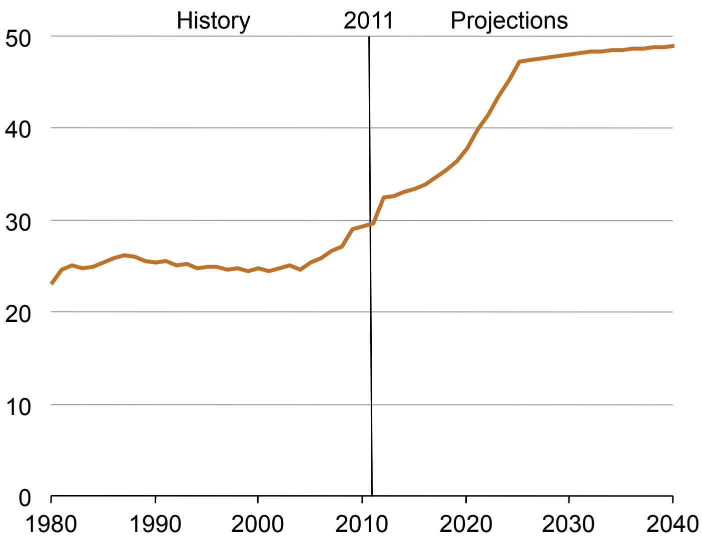
Energy demand for LDVs declines from 16.1 quadrillion Btu in 2011 to 13.0 quadrillion Btu in 2040, in contrast to 0.9-percent average annual growth from 1975 to 2011. Higher fuel economy for LDVs more than offsets modest growth in vehicle miles traveled (VMT) per driver.

Energy demand for HDVs (including tractor trailers, buses, vocational vehicles, and heavy-duty pickups and vans) increases the fastest among transportation modes, from 5.2 quadrillion Btu in 2011 to 7.6 quadrillion Btu in 2040, as a result of increased travel as economic output grows. The increase in energy demand for HDVs is tempered by standards for HDV fuel efficiency and greenhouse gas (GHG) emissions starting in 2014.

Energy demand for aircraft increases from 2.5 quadrillion Btu in 2011 to 2.9 quadrillion Btu in 2040. Increases in personal air travel are offset by gains in aircraft fuel efficiency, while air freight movement grows with higher exports. Energy consumption for marine and rail travel increases as industrial output rises, and pipeline energy use rises moderately as increasing volumes of natural gas are produced closer to end-use markets.

## CAFE and greenhouse gas emissions standards boost light-duty vehicle fuel economy

**Figure 71. Average fuel economy of new light-duty vehicles, 1980-2040 (miles per gallon, CAFE compliance values)**

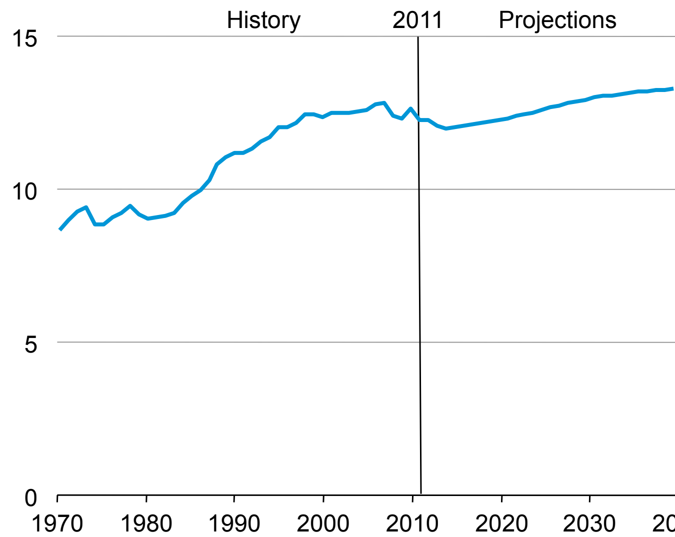



The 1978 introduction of corporate average fuel economy (CAFE) standards for LDVs increased their average fuel economy from 19.9 mpg in 1978 to 26.2 mpg in 1987. Despite technological improvement, fuel economy fell to between 24 and 27 mpg over the next two decades, as sales of light trucks increased from 18 percent of new LDV sales in 1980 to 55 percent in 2004 [*127*]. The subsequent rise in fuel prices, reduction in sales of light trucks, and more stringent CAFE standards for light-duty trucks starting in model year (MY) 2008 and for passenger cars in MY 2011, resulted in a rise in estimated LDV fuel economy to 29.0 mpg in 2011 [*128*].

The National Highway Traffic Safety Administration (NHTSA) and the U.S. Environmental Protection Agency have jointly announced new GHG emissions and CAFE standards for MY 2012 through MY 2025 [*129*, *130*], which are included in AEO2013. As a result, the fuel economy of new LDVs, measured in terms of their compliance values in CAFE testing [*131*], rises from 32.5 mpg in 2012 to 47.3 mpg in 2025 (Figure 71). The GHG emissions and CAFE standards are held roughly constant after 2025, but fuel economy continues to rise, to 49.0 mpg in 2040, as new fuel-saving technologies are adopted. In 2040, passenger car fuel economy averages 56.1 mpg and light-duty truck fuel economy averages 40.5 mpg.

## Travel demand for personal vehicles continues to grow, but more slowly than in the past

**Figure 72. Vehicle miles traveled per licensed driver, 1970-2040 (thousand miles)**



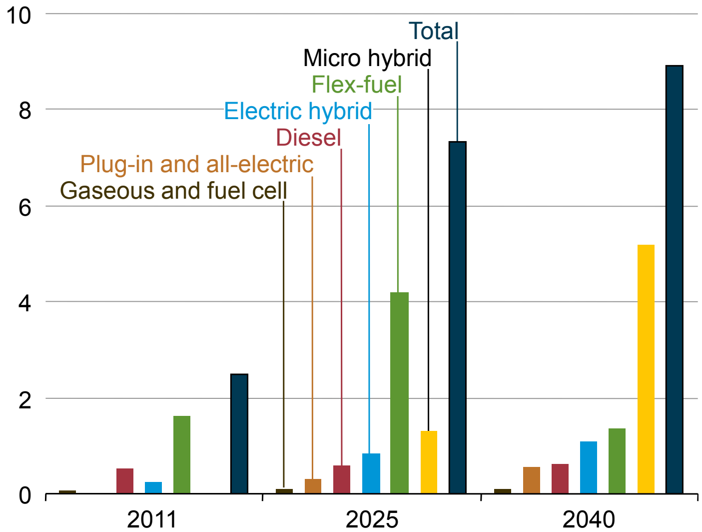

Personal vehicle travel demand, measured as annual VMT per licensed driver, grew at an average annual rate of 1 percent from 1970 to 2007, from about 8,700 miles per driver in 1970 to 12,800 miles in 2007. Since peaking in 2007, travel per licensed driver has declined because of rapidly increasing fuel prices and the economic recession.

Demographic changes moderate projected growth in VMT per licensed driver, which grows by an average of 0.3 percent per year, remaining below the 2007 level until 2029 and then growing to 13,300 miles in 2040 (Figure 72). Although vehicle sales rise through 2040, the number of vehicles per licensed driver declines from the all-time peak of 1.12 in 2007 to 1.01 in 2040. Further, unemployment remains above prerecession levels until around 2020, tempering the growth in demand for personal travel.

From 2011 to 2040, the price of motor gasoline increases by 26 percent (on a Btu basis), while real disposable personal income grows by 95 percent. Faster growth in income than fuel price lowers the percentage of income spent on fuel, boosting travel demand. In addition, the increase in fuel costs is more than offset by a 50-percent improvement in new vehicle fuel economy. Implementation of the new GHG and CAFE standards for LDVs lowers the cost of driving per mile and leads to growth in personal travel demand. Personal vehicle travel demand could vary, however, depending on several uncertainties, including the impact of changing demographics on travel behavior, the intensity of mass transit use, and other factors discussed above, such as fuel prices. The implications of a possible long-term decline in VMT per licensed driver are considered in the "Issues in focus" section of this report (see "Petroleum import dependence in a range of cases").

## Sales of alternative fuel, fuel flexible, and hybrid vehicles sales rise

**Figure 73. Sales of light-duty vehicles using non-gasoline technologies by type, 2011, 2025, and 2040 (million vehicles sold)**




LDVs that use diesel, other alternative fuels, hybrid-electric, or all-electric systems play a significant role in meeting more stringent GHG emissions and CAFE standards over the projection period. Sales of such vehicles increase from 20 percent of all new LDV sales in 2011 to 49 percent in 2040 in the *AEO2013* Reference case.

Micro hybrid vehicles, defined here as conventional gasoline vehicles with micro hybrid systems that manage engine operation at idle, represent 28 percent of new LDV sales in 2040, the largest share among vehicles using diesel, alternative fuels, hybrid-electric, or all-electric systems.

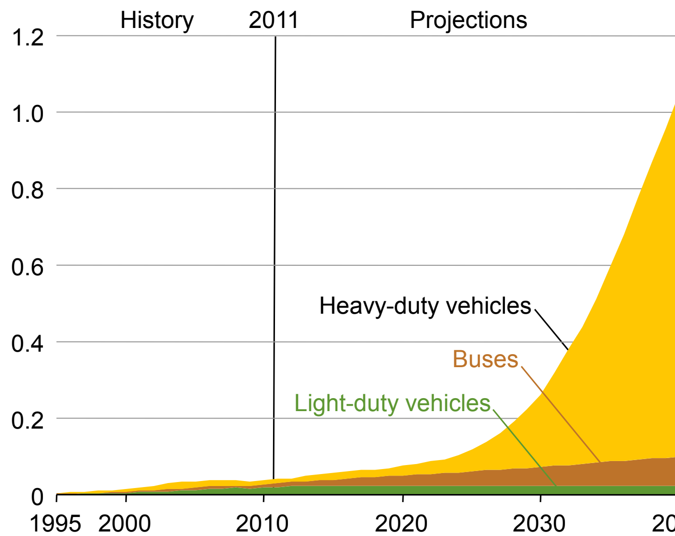
Flex-fuel vehicles (FFVs), which can use blends of ethanol up to 85 percent, represent the second largest share of these vehicle types in 2040, at 7 percent of all new LDV sales. Current incentives for manufacturers selling FFVs, which are available in the form of fuel economy credits earned for CAFE compliance, expire in 2019. As a result, the FFV share of LDV sales rises over the next decade and then declines.

Sales of hybrid electric and all-electric vehicles that use stored electric energy for motive power grow considerably in the Reference case (Figure 73). Gasoline- and diesel-electric hybrid vehicles account for 6 percent of total LDV sales in 2040; and plug-in hybrid and all-electric vehicles account for 3 percent of total LDV sales, or 6 percent of sales of vehicles using diesel, alternative fuels, hybrid, or all-electric systems.

The diesel vehicle share of total sales remains constant over the projection period at about 4 percent of total LDV sales. Light-duty gaseous and fuel cell vehicles account for less than 1 percent of new vehicle sales throughout the projection period because of limited fueling infrastructure and high incremental vehicle costs.

## Heavy-duty vehicles dominate natural gas consumption in the transportation sector

**Figure 74. Natural gas consumption in the transportation sector, 1995-2040 (quadrillion Btu)**



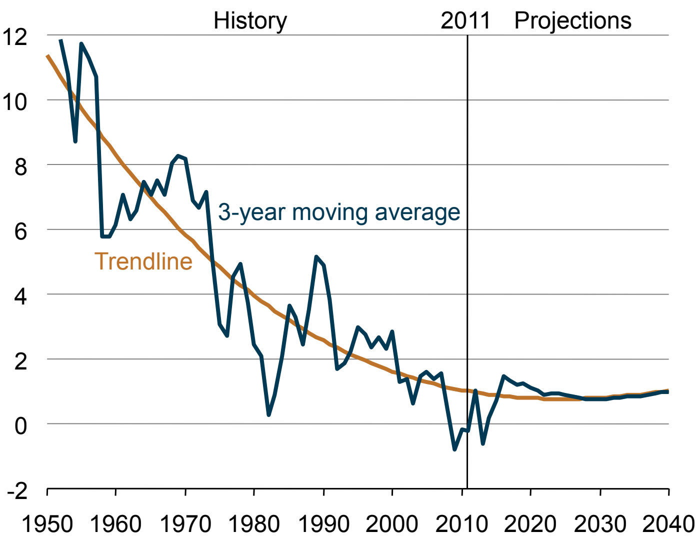

Natural gas, as compressed natural gas (CNG) and liquefied natural gas (LNG), is the fastest-growing fuel in the transportation sector, with an average annual growth rate of 11.9 percent from 2011 to 2040 (Figure 74). HDVs—which include tractor trailers, vocational vehicles, buses, and heavy-duty pickups and vans with a gross vehicle weight rating (GVWR) of 10,001 pounds or more—lead the growth in natural gas demand throughout the projection period. Natural gas fuel consumption by HDVs increases from almost zero in 2011 to more than 1 quadrillion Btu in 2040, at an average annual growth rate of 14.6 percent.

Although HDVs fueled by natural gas have significant incremental costs in comparison with their diesel-powered counterparts, the increase in natural gas consumption for HDVs is spurred by low prices of natural gas compared with diesel fuel, as well as purchases of natural gas vehicles for relatively high-VMT applications, such as tractor trailers.

The total number of miles traveled annually by HDVs grows by 82 percent in the Reference case, from 240 billion miles in 2011 to 438 billion miles in 2040, for an average annual increase of 2.1 percent. HDVs, those with a GVWR greater than 26,000 pounds (primarily tractor trailers), account for about three-fourths of truck VMT and 91 percent of natural gas consumption by all HDVs in 2040. The rise in VMT is supported by rising economic output over the projection period and an increase in the number of trucks on the road, from 9.0 million in 2011 to 13.7 million in 2040.

## Growth in electricity use slows but still increases by 28 percent from 2011 to 2040

**Figure 75. U.S. electricity demand growth, 1950-2040 (percent, 3-year moving average)**



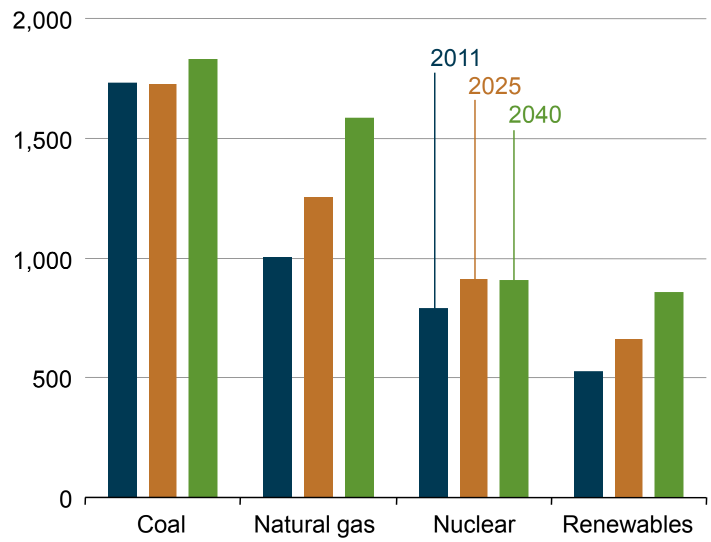

The growth of electricity demand (including retail sales and direct use) has slowed in each decade since the 1950s, from a 9.8-percent annual rate of growth from 1949 to 1959 to only 0.7 percent per year in the first decade of the 21st century. In the *AEO2013* Reference case, electricity demand growth remains relatively slow, as increasing demand for electricity services is offset by efficiency gains from new appliance standards and investments in energy-efficient equipment (Figure 75). Total electricity demand grows by 28 percent in the projection (0.9 percent per year), from 3,839 billion kilowatthours in 2011 to 4,930 billion kilowatthours in 2040.

Retail electricity sales grow by 24 percent (0.7 percent per year) in the Reference case, from 3,725 billion kilowatthours in 2011 to 4,608 billion kilowatthours in 2040. Residential electricity sales also grow by 24 percent, to 1,767 billion kilowatthours in 2040, spurred by population growth and continued population shifts to warmer regions with greater cooling requirements. Led by demand in the service industries, sales of electricity to the commercial sector increase by 27 percent, to 1,677 billion kilowatthours in 2040. Sales to the industrial sector grow by 17 percent, to 1,145 billion kilowatthours in 2040. Electricity sales to the transportation sector, although relatively small, triple from 6 billion kilowatthours in 2011 to 19 billion kilowatthours in 2040 with increasing sales of electric plug-in LDVs.

Electricity demand can vary with different assumptions about economic growth, electricity prices, and advances in energy-efficient technologies. In the High Economic Growth case, demand grows by 42 percent from 2011 to 2040, compared with 18 percent in the Low Economic Growth case and only 7 percent in the Best Available Technology case. Average electricity prices (in 2011 dollars) increase by 5 percent from 2011 to 2040 in the Low Economic Growth case and 13 percent in the High Economic Growth case, to 10.4 and 11.2 cents per kilowatthour, respectively, in 2040.

## Coal-fired plants continue to be the largest source of U.S. electricity generation

**Figure 76. Electricity generation by fuel, 2011, 2025, and 2040 (billion kilowatthours)**




Coal-fired power plants continue to be the largest source of electricity generation in the *AEO2013* Reference case (Figure 76), but their market share declines significantly. From 42 percent in 2011, coal's share of total U.S. generation declines to 38 percent in 2025 and 35 percent in 2040. Approximately 15 percent of the coal-fired capacity active in 2011 is expected to be retired by 2040 in the Reference case, while only 4 percent of new generating capacity added is coal-fired. Existing coal-fired units that have undergone environmental equipment retrofits continue to operate throughout the projection.

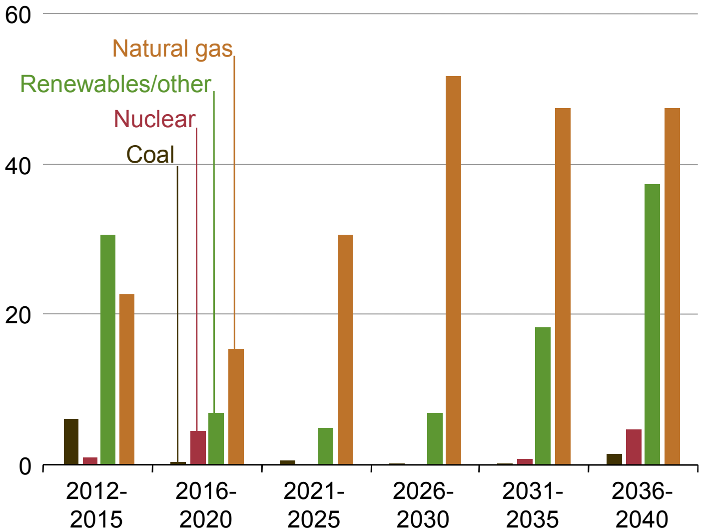
Generation from natural gas increases by an average of 1.6 percent per year from 2011 to 2040, and its share of total generation grows from 24 percent in 2011 to 27 percent in 2025 and 30 percent in 2040. The relatively low cost of natural gas makes the dispatching of existing natural gas plants more competitive with coal plants and, in combination with relatively low capital costs, makes plants fueled by natural gas an alternative choice for new generation capacity.

Generation from renewable sources grows by 1.7 percent per year on average in the Reference case, and the share of total generation rises from 13 percent in 2011 to 16 percent in 2040. The nonhydropower share of total renewable generation increases from 38 percent in 2011 to 65 percent in 2040.

Generation from U.S. nuclear power plants increases by 0.5 percent per year on average from 2011 to 2040, with most of the growth between 2011 and 2025, but the share of total U.S. electricity generation declines from 19 percent in 2011 to 17 percent in 2040, as the growth in nuclear generation is outpaced by growth in generation using natural gas and renewables.

## Most new capacity additions use natural gas and renewables

**Figure 77. Electricity generation capacity additions by fuel type, including combined heat and power, 2012-2040 (gigawatts)**



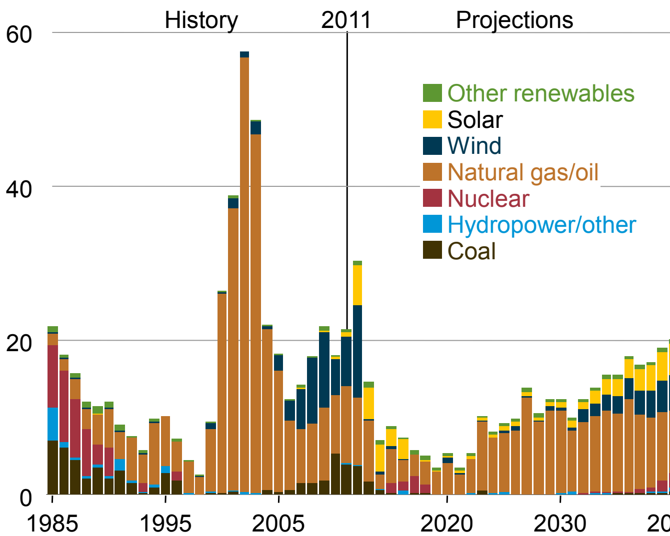

Decisions to add capacity, and the choice of fuel for new capacity, depend on a number of factors [*132*]. With growing electricity demand and the retirement of 103 gigawatts of existing capacity, 340 gigawatts of new generating capacity [*133*] is added in the *AEO2013* Reference case from 2012 to 2040 (Figure 77).

Natural gas-fired plants account for 63 percent of capacity additions from 2012 to 2040 in the Reference case, compared with 31 percent for renewables, 3 percent for coal, and 3 percent for nuclear. Escalating construction costs have the largest impact on capital-intensive technologies, which include nuclear, coal, and renewables. However, federal tax incentives, state energy programs, and rising prices for fossil fuels increase the competitiveness of renewable and nuclear capacity. Current federal and state environmental regulations also affect the use of fossil fuels, particularly coal. Uncertainty about future limits on GHG emissions and other possible environmental programs also reduces the competitiveness of coal-fired plants (reflected in the *AEO2013* Reference case by adding 3 percentage points to the cost of capital for new coal-fired capacity).

Uncertainty about electricity demand growth and fuel prices also affects capacity planning. Total capacity additions from 2012 to 2040 range from 252 gigawatts in the Low Economic Growth case to 498 gigawatts in the High Economic Growth case. In the Low Oil and Gas Resource case, natural gas prices are higher than in the Reference case, and new natural gas-fired capacity added from 2012 to 2040 totals 152 gigawatts, or 42 percent of total additions. In the High Oil and Gas Resource case, delivered natural gas prices are lower than in the Reference case, and 311 gigawatts of new natural gas-fired capacity is added from 2012 to 2040, accounting for 82 percent of total new capacity.

## Additions to power plant capacity slow after 2012 but accelerate beyond 2023

**Figure 78. Additions to electricity generating capacity, 1985-2040 (gigawatts)**



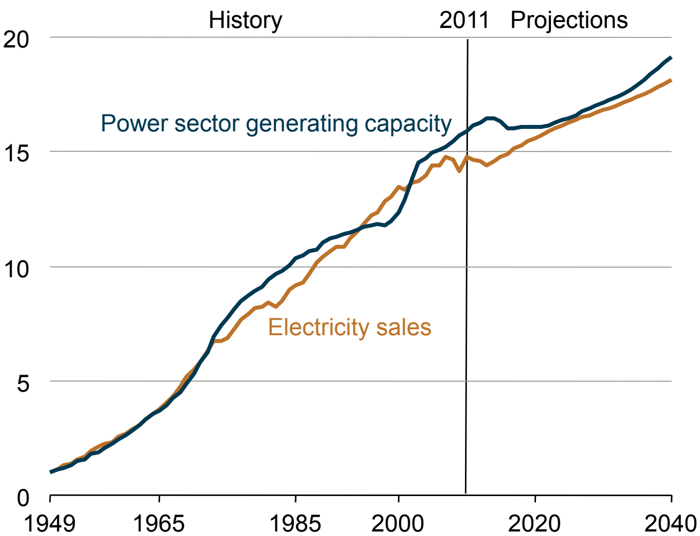

Typically, investments in electricity generation capacity have gone through boom-and-bust cycles. Periods of slower growth have been followed by strong growth in response to changing expectations for future electricity demand and fuel prices, as well as changes in the industry, such as restructuring (Figure 78). A construction boom in the early 2000s saw capacity additions averaging 35 gigawatts a year from 2000 to 2005. Since then, average annual builds have dropped to 18 gigawatts per year from 2006 to 2011.

In the *AEO2013* Reference case, capacity additions from 2012 to 2040 total 340 gigawatts, including new plants built not only in the power sector but also by end-use generators. Annual additions in 2012 and 2013 remain relatively high, averaging 22 gigawatts per year. Of those early builds, 51 percent are renewable plants built to take advantage of federal tax incentives and to meet state renewable standards.

Annual builds drop significantly after 2013 and remain below 9 gigawatts per year until 2023. During that period, existing capacity is adequate to meet growth in demand in most regions, given the earlier construction boom and relatively slow growth in electricity demand after the economic recession. Between 2025 and 2040, average annual builds increase to 14 gigawatts per year, as excess capacity is depleted and the rate of total capacity growth is more consistent with electricity demand growth. About 68 percent of the capacity additions from 2025 to 2040 are natural gas-fired, given the higher construction costs for other capacity types and uncertainty about the prospects for future limits on GHG emissions.

## Growth in generating capacity parallels rising demand for electricity

**Figure 79. Electricity sales and power sector generating capacity, 1949-2040 (indexes, 1949 = 1.0)**



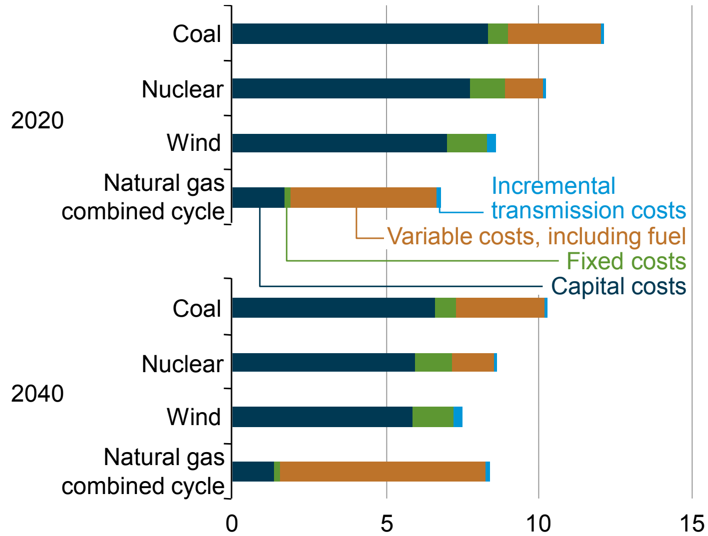

Over the long term, growth in electricity generating capacity parallels the growth in end-use demand for electricity. Unexpected shifts in demand or dramatic changes affecting capacity investment decisions can, however, cause imbalances that may take years to be worked out.

Figure 79 shows indexes summarizing relative changes in total generating capacity and electricity demand. During the 1950s and 1960s, the capacity and demand indexes tracked closely. The energy crises of the 1970s and 1980s, together with other factors, slowed electricity demand growth, and capacity growth outpaced demand for more than 10 years thereafter, as planned units continued to come on line. Demand and capacity did not align again until the mid-1990s. Then, in the late 1990s, uncertainty about deregulation of the electricity industry caused a downturn in capacity expansion, and another period of imbalance followed, with growth in electricity demand exceeding capacity growth.

In 2000, a boom in construction of new natural gas-fired plants began, bringing capacity back into balance with demand and creating excess capacity. Construction of new wind capacity that sometimes needs backup capacity because of intermittency also began to grow after 2000. More recently, the 2007-2009 economic recession caused a significant drop in electricity demand, which has yet to recover. Slow near-term growth in electricity demand in the *AEO2013* Reference case creates excess generating capacity. Capacity currently under construction is completed, but a limited amount of additional capacity is built before 2025, while older capacity is retired. By 2025, capacity growth and demand growth are in balance again, and they grow at similar rates through 2035. In the later years, total capacity grows at a rate slightly higher than demand, due in part to an increasing share of intermittent renewable capacity that does not contribute to meeting demand in the same proportion as dispatchable capacity.

## Costs and regulatory uncertainties vary across options for new capacity

**Figure 80. Levelized electricity costs for new power plants, excluding subsidies, 2020 and 2040 (2011 cents per kilowatthour)**




Technology choices for new generating capacity are based largely on capital, operating, and transmission costs [*134*]. Coal, nuclear, and wind plants are capital-intensive (Figure 80), whereas operating (fuel) expenditures make up most of the costs for natural gas plants. Capital costs depend on such factors as equipment costs, interest rates, and cost recovery periods, which vary with technology. Fuel costs vary with operating efficiency, fuel price, and transportation costs.

In addition to considerations of levelized costs [*135*], some technologies and fuels receive subsidies, such as production or ITCs. Also, new plants must satisfy local and federal emissions standards and must be compatible with the utility's load profile.

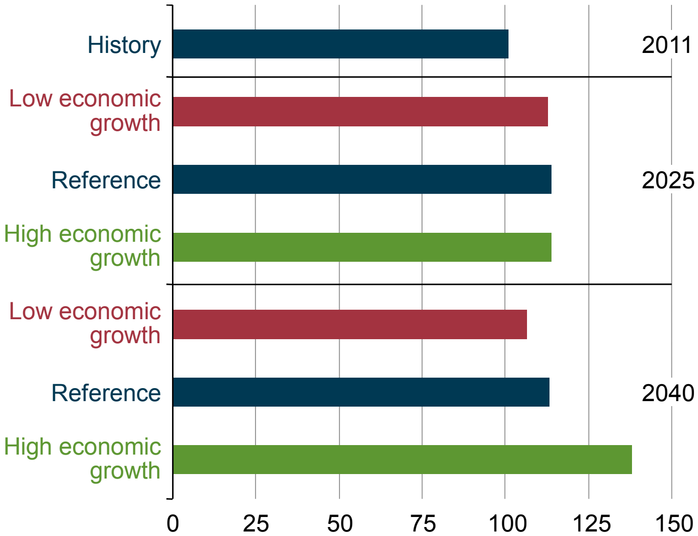
Regulatory uncertainty also affects capacity planning. New coal plants may require carbon control and sequestration equipment, resulting in higher material, labor, and operating costs. Alternatively, coal plants without carbon controls could incur higher costs for siting and permitting. Because nuclear and renewable power plants (including wind plants) do not emit GHGs, their costs are not directly affected by regulatory uncertainty in this area.

Capital costs can decline over time as developers gain technology experience, with the largest rate of decline observed in new technologies. In the *AEO2013* Reference case, the capital costs of new technologies are adjusted upward initially to compensate for the optimism inherent in early estimates of project costs, then decline as project developers gain experience. 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.

# Electricity capacity

## Nuclear power plant capacity grows slowly through uprates and new builds

### Figure 81. Electricity generating capacity at U.S. nuclear power plants in three cases, 2011, 2025, and 2040 (gigawatts)

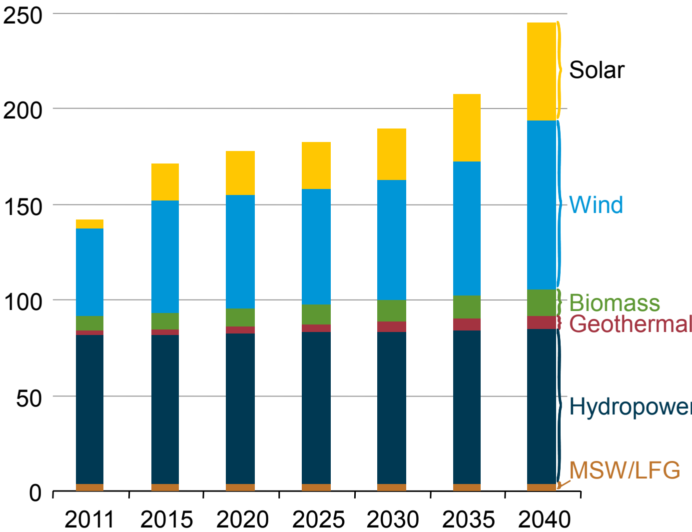



In the *AEO2013* Reference case, nuclear power capacity increases from 101.1 gigawatts in 2011 to a high of 114.1 gigawatts in 2025, before declining to 108.5 gigawatts in 2036 (Figure 81), largely as a result of plant retirements. New additions in the later years of the projection bring nuclear capacity back up to 113.1 gigawatts in 2040. The capacity increase through 2025 includes 8.0 gigawatts of expansion at existing plants and 5.5 gigawatts of new capacity, which includes completion of a conventional reactor at the Watts Bar site. Four advanced reactors, reported as under construction, also are assumed to be brought online by 2020 and to be eligible for federal financial incentives. High construction costs for nuclear plants, especially relative to natural gas-fired plants, make additional options for new nuclear capacity uneconomical until the later years of the projection, when an additional 5.5 gigawatts is added. Nuclear capacity additions vary with assumptions about overall demand for electricity. Across the Economic Growth cases, net additions of nuclear capacity from 2012 to 2040 range from 5.5 gigawatts in the Low Economic Growth case to 36.1 gigawatts in the High Economic Growth case.

One nuclear unit, Oyster Creek, is expected to be retired at the end of 2019, as announced by Exelon in December 2010. An additional 6.5 gigawatts of nuclear capacity is assumed to be retired by 2036 in the Reference case. All other existing nuclear units continue to operate through 2040 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 60 years of operation (for more discussion, see "Issues in focus"). With costs for natural gas-fired generation rising in the Reference case and uncertainty about future regulation of GHG emissions, the economics of keeping existing nuclear power plants in operation are favorable.

## Solar photovoltaics and wind dominate renewable capacity growth

### Figure 82. Renewable electricity generation capacity by energy source, including end-use capacity, 2011-2040 (gigawatts)



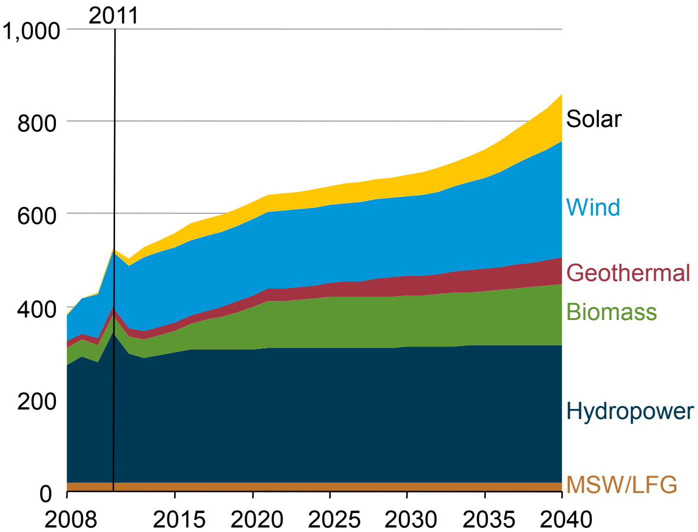

Renewable generating capacity accounts for nearly one-fifth of total generating capacity in 2040 in the *AEO2013* Reference case. Nearly all renewable capacity additions over the period consist of nonhydropower capacity, which grows by more than 150 percent from 2011 to 2040 (Figure 82).

Solar generation capacity leads renewable capacity growth, increasing by more than 1,000 percent, or 46 gigawatts, from 2011 to 2040. Wind capacity follows closely, accounting for an additional 42 gigawatts of new renewable capacity by 2040. Nonetheless, wind continues to be the leading source of nonhydropower renewable capacity in 2040, given its relatively high initial capacity in 2011, after a decade of exponential growth resulting from the availability of production tax credits and other incentives. Although geothermal and dedicated biomass generation capacity do not increase on the same scale as wind and solar (contributing an additional 5 gigawatts and 7 gigawatts, respectively, over the projection period), biomass capacity nearly doubles and geothermal capacity more than triples over the same period.

Renewable capacity additions are supported by state RPS, the federal renewable fuels standard, and federal tax credits. Near-term growth is strong as developers build capacity to qualify for tax credits that expire at the end of 2012, 2013, and 2016. After 2016, capacity growth through 2030 is minimal, given relatively slower growth in electricity demand, low natural gas prices, and the stagnation or expiration of the state and federal policies that support renewable capacity additions. As the need for new generation capacity increases, however, and as renewables become increasingly cost-competitive in selected regions, growth in nonhydropower renewable generation capacity rebounds during the final decade of the Reference case projection from 2030 to 2040.

## Solar, wind, and biomass lead growth in renewable generation, hydropower remains flat

### Figure 83. Renewable electricity generation by type, including end-use generation, 2008-2040 (billion kilowatthours)

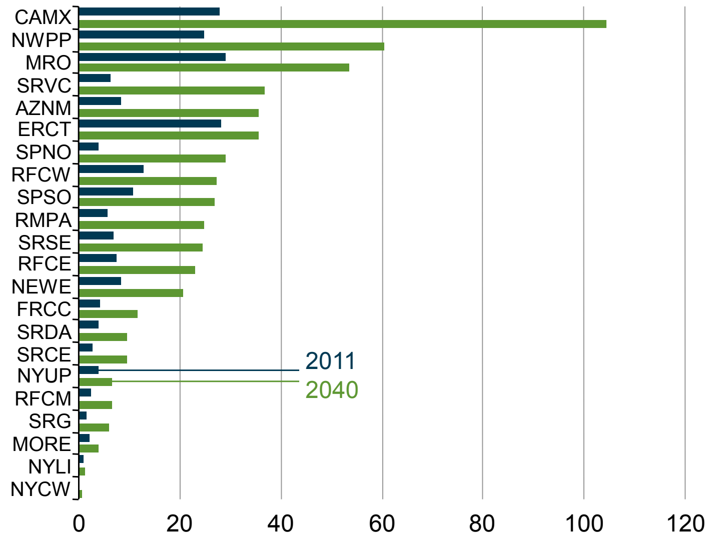



In the *AEO2013* Reference case, renewable generation increases from 524 billion kilowatthours in 2011 to 858 billion kilowatthours in 2040, growing by an average of 1.7 percent per year (Figure 83). Wind, solar, and biomass account for most of the growth. The increase in wind-powered generation from 2011 to 2040, at 134 billion kilowatthours, or 2.6 percent per year, represents the largest absolute increase in renewable generation. Generation from solar energy grows by 92 billion kilowatthours over the same period, representing the highest annual average growth at 9.8 percent per year. Biomass increases by 95 billion kilowatthours over the projection period, for an average annual increase of 4.5 percent.

Hydropower production drops in 2012, from 325 billion kilowatthours in 2011, as existing plants are assumed to continue operating at their long-term average production levels. Even with little growth in capacity, hydropower remains the leading source of renewable generation throughout the projection. Although total wind capacity exceeds hydropower capacity in 2040, wind generators typically operate at much lower capacity factors, and their total generation is lower. Biomass is the third-largest source of renewable generation throughout the projection, with rapid growth particularly in the first decade of the period, reaching 102 billion kilowatthours in 2021 from 37 billion kilowatthours in 2011. The strong growth is a result primarily of increased penetration of co-firing technology in the electric power sector, encouraged by state-level policies and increasing cost-competitiveness with coal in parts of the Southeast.

## State renewable portfolio standards increase renewable electricity generation

### Figure 84. Regional nonhydropower renewable electricity generation, including end-use generation, 2011 and 2040 (billion kilowatthours)




Regional growth in nonhydroelectric renewable electricity generation is based largely on three factors: availability of renewable energy resources, cost competitiveness with fossil fuel technologies, and the existence of state RPS programs that require the use of renewable generation. After a period of robust RPS enactments in several states, the past few years have been relatively quiet in terms of state program expansions.

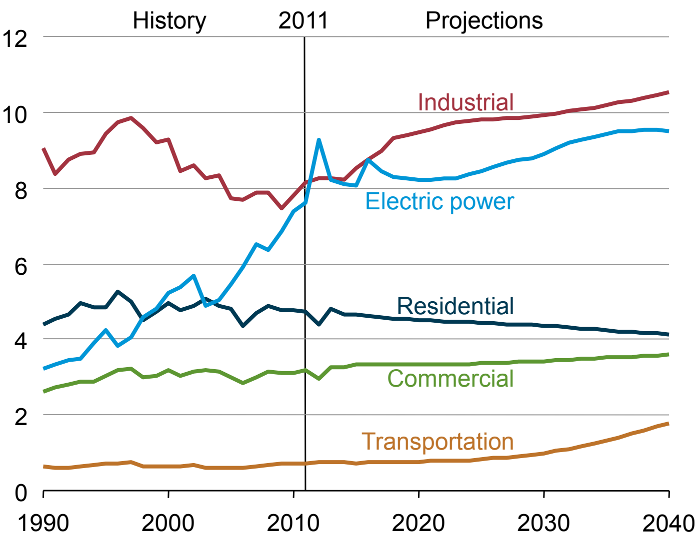
In the *AEO2013* Reference case, the highest level of nonhydroelectric renewable generation in 2040, at 104 billion kilowatthours, occurs in the WECC California (CAMX) region (Figure 84), whose area approximates the California state boundaries. (For a map of the electricity regions and a definition of the acronyms, see Appendix F.) The three largest sources of nonhydro-electric renewable generation in 2040 in that region are geothermal, solar, and wind energy. The region encompassing the Pacific Northwest has the most renewable generation in the United States when hydroelectric is included, which is the source of most of the region's renewable electricity generation.

State RPS programs heavily influence the growth of solar capacity in the eastern states. A prime example is the Reliability First Corporation/East (RFCE) region, where 7.5 billion kilowatthours of electricity is generated from solar resources in 2040, mostly from end-use capacity. The RFCE region is not known for a strong solar resource base, and the projected installations are in response to the federal tax credits, state incentives, and solar energy requirements embedded in state RPS programs. The CAMX region has the highest total for solar generation in 2040 at 36 billion kilowatthours, including 10 billion kilowatthours of generation from end-use solar capacity.

# Natural gas consumption

## Industrial and electric power sectors lead U.S. growth in natural gas consumption

**Figure 85. Natural gas consumption by sector, 1990-2040 (trillion cubic feet)**




U.S. total natural gas consumption grows from 24.4 trillion cubic feet in 2011 to 29.5 trillion cubic feet in 2040 in the *AEO2013* Reference case. Natural gas use increases in all the end-use sectors except residential (Figure 85), where consumption declines as a result of improvements in appliance efficiency and falling demand for space heating, attributable in part to population shifts to warmer regions of the country.

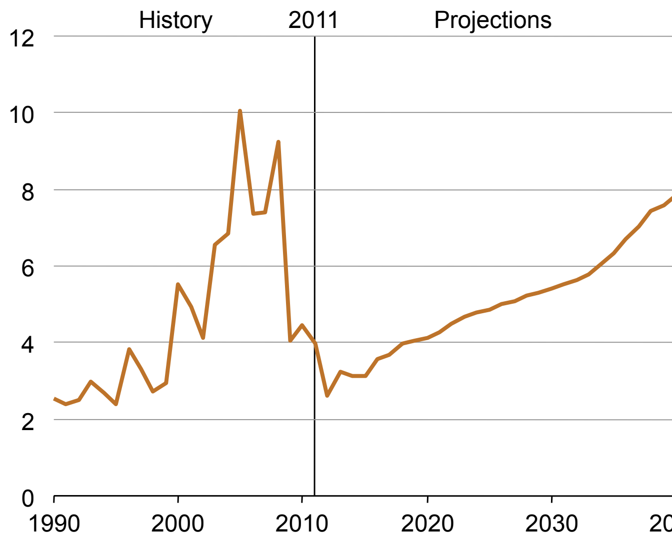
Despite falling early in the projection period from a spike in 2012, which resulted from very low natural gas prices relative to coal, consumption of natural gas for power generation increases by an average of 0.8 percent per year, with more natural gas used for electricity production as relatively low prices make natural gas more competitive with coal. Over the projection period, the natural gas share of total power generation grows, while the coal share declines.

Natural gas consumption in the industrial sector increases by an average of 0.5 percent per year from 2011 to 2040. This includes 0.7 trillion cubic feet of natural gas used in GTL, which is largely consumed in the transportation sector. Industrial output grows as the energy-intensive industries take advantage of relatively low natural gas prices, particularly through 2025. After 2025, growth in the sector slows in response to rising prices and increased international competition.

Although vehicle uses currently account for only a small part of total U.S. natural gas consumption, the projected percentage growth in natural gas demand by vehicles is the largest percentage growth in the projection. With incentives and low natural gas prices leading to increased demand for natural gas as a fuel for HDVs, particularly after 2025, consumption in vehicles increases from about 40 billion cubic feet in 2011 to just over 1 trillion cubic feet in 2040.

## Natural gas prices rise with an expected increase in production costs after 2015

**Figure 86. Annual average Henry Hub spot natural gas prices, 1990-2040 (2011 dollars per million Btu)**



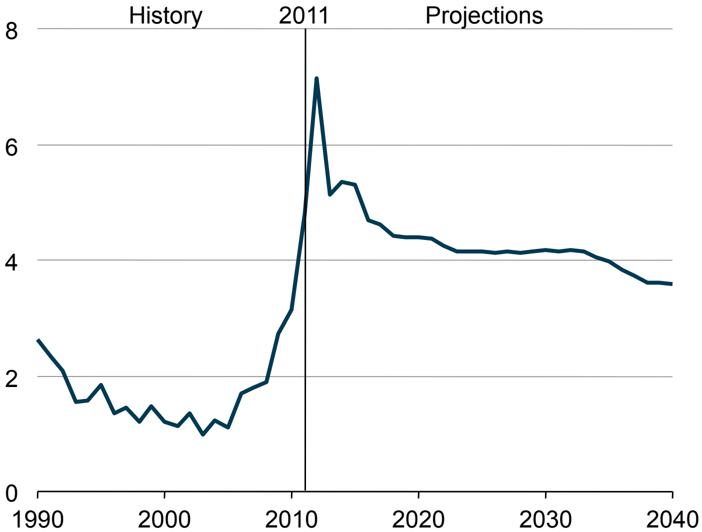

U.S. natural gas prices have remained relatively low over the past several years as a result of abundant domestic supply and efficient methods of production. However, the cost of developing new incremental production needed to support continued growth in natural gas consumption and exports rises gradually in the *AEO2013* Reference case, leading to an increase in the Henry Hub spot price. Henry Hub spot prices for natural gas increase by an average of about 2.4 percent per year, to $7.83 per million Btu (2011 dollars) in 2040 (Figure 86).

As of January 1, 2011, total proved and unproved U.S. natural gas resources (total recoverable resources) were estimated to total 2,327 trillion cubic feet. Over time, however, the depletion of resources in inexpensive areas leads producers to basins where recovery of the gas is more difficult and more expensive, causing the cost of production to rise gradually.

In the Reference case, natural gas prices remain low at the beginning of the projection period, as producers continue to extract natural gas resources from the most productive and inexpensive areas. Drilling activity remains robust despite the relatively low prices (below $4 per million Btu), particularly as producers extract natural gas from areas with high contents of NGL or oil. Prices begin to rise after 2015, and they continue rising in the projection through 2040.

## Energy from natural gas remains far less expensive than energy from oil through 2040

**Figure 87. Ratio of Brent crude oil price to Henry Hub spot natural gas price in energy-equivalent terms, 1990-2040**



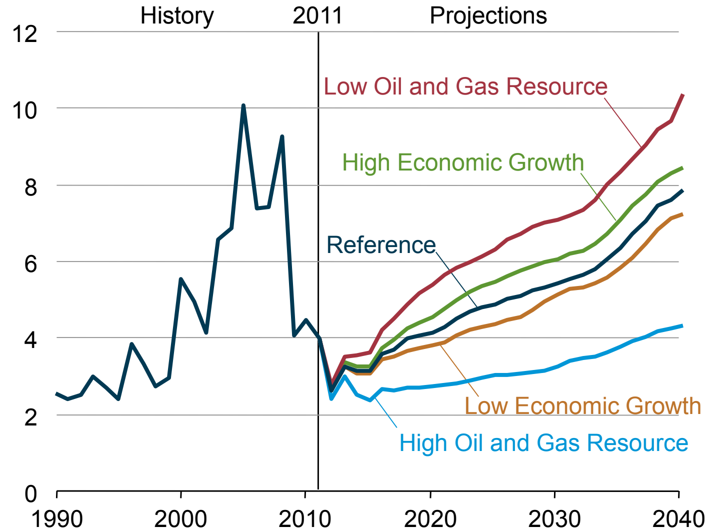

The ratio of oil prices to natural gas prices is defined in terms of the Brent crude oil price and the Henry Hub spot natural gas price on an energy-equivalent basis. U.S. natural gas prices are determined largely on a regional basis, in response to supply and demand conditions in North America. Oil prices are more responsive to global supply and demand. A 1:1 ratio indicates that crude oil and natural gas cost the same in terms of energy content. On that basis, crude oil remains far more expensive than natural gas through 2040 (Figure 87), but the difference in the costs of the two fuels narrows over time.

With rising demand and production costs, both crude oil and natural gas prices increase through 2040; however, the oil price rises more slowly than the natural gas price, bringing the oil-to-gas price ratio down from its 2012 level. Low natural gas prices, the result of abundant domestic supply and weak winter demand, combined with high oil prices, caused a sharp rise in the oil-to-gas price ratio in 2012.

Natural gas prices nearly double in the *AEO2013* Reference case, from $3.98 per million Btu in 2011 to $7.83 in 2040 (2011 dollars), and oil prices increase by about 50 percent, to $28.05 per million Btu in 2040. Over the entire period, the ratio remains well above the levels of the two previous decades. Oil and natural gas prices were more strongly aligned until about 2006, and the ratio of oil prices to natural gas prices was lower. Since 2006, however, natural gas prices have fallen as a result of abundant domestic supplies and production. In contrast, oil prices have increased and remained relatively high as global demand has increased over the past several years.

## Natural gas prices depend on economic growth and resource recovery rates among other factors

**Figure 88. Annual average Henry Hub spot prices for natural gas in five cases, 1990-2040 (2011 dollars per million Btu)**




Future levels of natural gas prices depend on many factors, including macroeconomic growth rates and expected rates of resource recovery from natural gas wells. Higher rates of economic growth lead to increased consumption of natural gas (primarily in response to higher levels of housing starts, commercial floorspace, and industrial output), causing more rapid depletion of natural gas resources and a more rapid increase in the cost of developing new production, which push natural gas prices higher. The converse is true in the Low Economic Growth case (Figure 88).

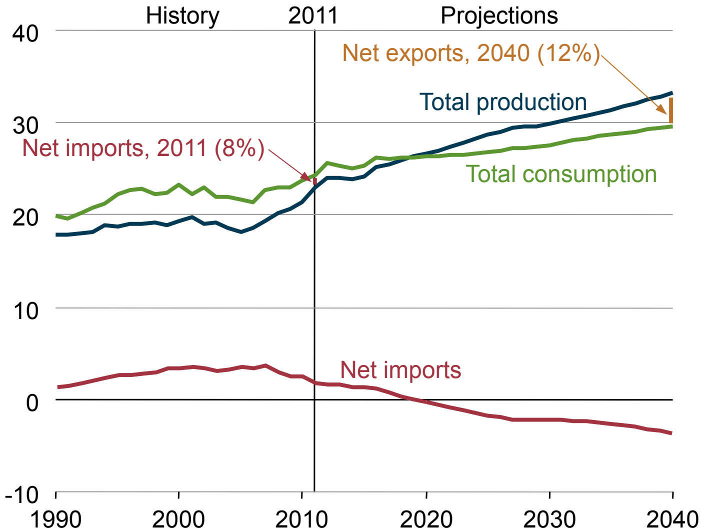
A lower rate of recovery from oil and gas wells implies higher costs per unit and higher prices. A higher rate of recovery implies lower costs per unit and lower prices. In comparison with the Reference case, the Low Oil and Gas Resource case assumes lower estimated ultimate recovery (EUR) from each shale well or tight well. The High Oil and Gas Resource case represents a more extreme case, with higher estimates for recoverable crude oil and natural gas resources in tight wells and shale formations and for offshore resources in the lower 48 states and Alaska.

In both cases, there are mitigating effects that dampen the initial price response from the demand or supply shift. For example, lower natural gas prices lead to an increase in natural gas exports, which places some upward pressure on natural gas prices. In addition, lower prices are likely to lead to less drilling for natural gas and lower production potential, placing some upward pressure on natural gas prices.

# Natural gas production

## With production outpacing consumption, U.S. exports of natural gas exceed imports

**Figure 89. Total U.S. natural gas production, consumption, and net imports, 1990-2040 (trillion cubic feet)**



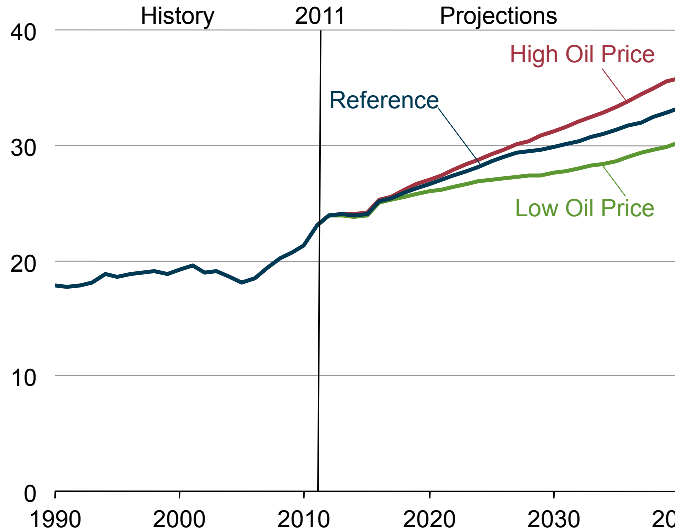

The United States consumed more natural gas than it produced in 2011, with net imports of almost 2 trillion cubic feet. As domestic supply has increased, however, natural gas prices have declined, making the United States a less attractive market and reducing U.S. imports. Conversely, lower prices have made purchases of U.S. natural gas more attractive, increasing exports. In the *AEO2013* Reference case, the United States becomes a net exporter of natural gas by 2020 (Figure 89).

Production growth, led by increased development of shale gas resources, outpaces consumption growth in the Reference case—a pattern that continues through 2040. As a result, exports continue to grow at a rate of about 17.7 percent per year from 2020 to 2040. Net exports in 2020 are less than 1 percent of total consumption; in 2040 they are 12 percent of consumption.

U.S. natural gas production increases by about 1 percent per year from 2011 to 2040 in the Reference case, meeting domestic demand while also allowing for more exports. The prospects for future exports are highly uncertain, however, depending on many factors that are difficult to anticipate, such as the development of new production capacity in foreign countries, particularly from deepwater reservoirs, shale gas deposits, and the Arctic.

## U.S. natural gas production is affected by oil prices through consumption and exports

**Figure 90. Total U.S. natural gas production in three oil price cases, 1990-2040 (trillion cubic feet per year)**



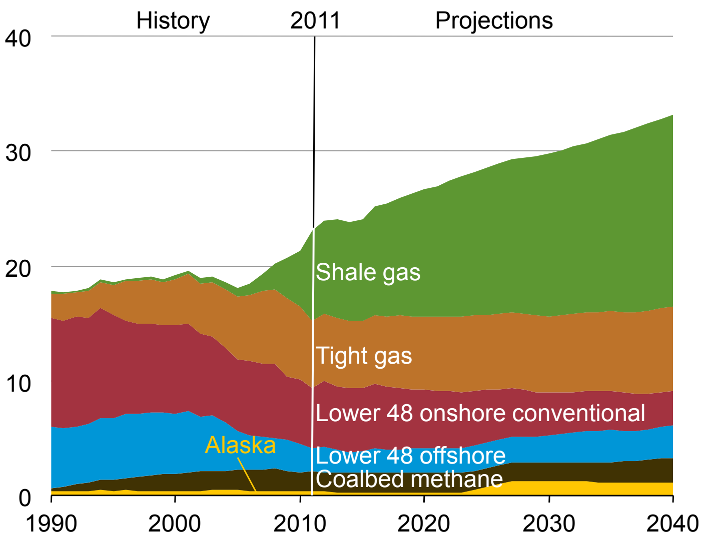

U.S. natural gas production is affected by crude oil prices primarily through changes in natural gas consumption and exports. Across the *AEO2013* oil price cases, the largest changes in natural gas use occur in natural gas converted into liquid fuels via GTL, directly consumed in transportation as CNG or LNG, and exported as LNG. Because world LNG prices are directly affected by crude oil prices, depending on regional market conditions, crude oil prices are important to the market value of LNG exported from the United States.

The profitability of using natural gas as a transportation fuel, or for exporting LNG, depends largely on the price differential between crude oil and natural gas. The greater the difference between crude oil and natural gas prices, the greater the incentive to use natural gas. For example, in the Low Oil Price case, average oil prices are about $7.80 per million Btu higher than natural gas prices from 2012 through 2040—a relatively low price differential that leads to virtually no use of natural gas for transportation and very little for LNG exports. In the High Oil Price case, the average price difference is about $24.30 per million Btu from 2012 through 2040, providing the incentives necessary to promote natural gas use in transportation applications and for export.

Across the price cases, total natural gas production varies by 5.6 trillion cubic feet in 2040 (Figure 90). Changes in LNG exports account for 3.6 trillion cubic feet of the difference. Direct consumption of natural gas for transportation varies by 2.1 trillion cubic feet between the two cases, and consumption for GTL production varies by 1.1 trillion cubic feet. Across the price cases, as natural gas production rises, so do natural gas prices; and as natural gas prices rise, consumption in the other end-use sectors falls by as much as 2.5 trillion cubic feet.

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

### Figure 91. Natural gas production by source, 1990-2040 (trillion cubic feet)




The 44-percent increase in total natural gas production from 2011 through 2040 in the *AEO2013* Reference case results from the increased development of shale gas, tight gas, and coalbed methane resources (Figure 91). Shale gas production, which grows by 113 percent from 2011 to 2040, is the greatest contributor to natural gas production growth. Its share of total production increases from 34 percent in 2011 to 50 percent in 2040. Tight gas and coalbed methane production also increase, by 25 percent and 24 percent, respectively, from 2011 to 2040, even as their shares of total production decline slightly. The growth in coalbed methane production is not realized until after 2035, when natural gas prices and demand levels are high enough to spur more drilling.

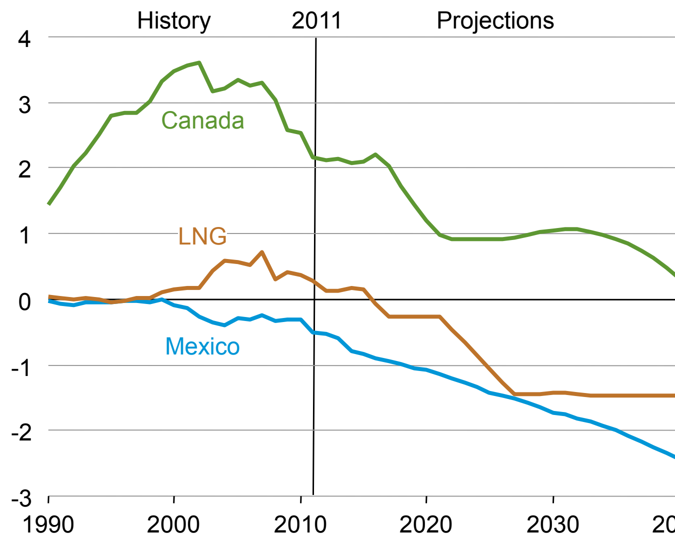
Offshore natural gas production declines by 0.3 trillion cubic feet from 2011 through 2014, as offshore exploration and development activities are directed toward oil-prone areas in the Gulf of Mexico. After 2014, offshore natural gas production recovers as prices rise, growing to 2.8 trillion cubic feet in 2040. As a result, from 2011 to 2040, offshore natural gas production increases by 35 percent.

Alaska natural gas production also increases in the Reference case with the advent of Alaska LNG exports to overseas customers beginning in 2024 and growing to 0.8 trillion cubic feet per year (2.2 billion cubic feet per day) in 2027. In 2040, Alaska natural gas production totals 1.2 trillion cubic feet.

Although total U.S. natural gas production rises throughout the projection, onshore nonassociated conventional production declines from 3.6 trillion cubic feet in 2011 to 1.9 trillion cubic feet in 2040, when it accounts for only about 6 percent of total domestic production, down from 16 percent in 2011.

## Pipeline exports increase as Canadian imports fall and exports to Mexico rise

### Figure 92. U.S. net imports of natural gas by source, 1990-2040 (trillion cubic feet)




With relatively low natural gas prices in the *AEO2013* Reference case, the United States becomes a net exporter of natural gas in 2020, and net exports grow to 3.6 trillion cubic feet in 2040 (Figure 92). Most of the projected growth in U.S. exports consists of pipeline exports to Mexico, which increase steadily over the projection period, as increasing volumes of imported natural gas from the United States fill the growing gap between Mexico's production and consumption. Exports to Mexico increase from 0.5 trillion cubic feet in 2011 to 2.4 trillion cubic feet in 2040.

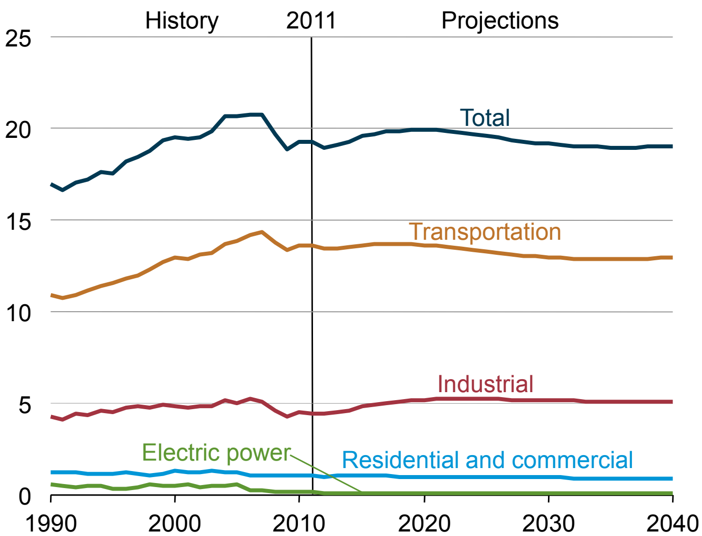
U.S. exports of domestically sourced LNG (excluding existing exports from the Kenai facility in Alaska, which fall to zero in 2013) begin in 2016 and rise to a level of 1.6 trillion cubic feet per year in 2027. One-half of the projected increase in U.S. exports of LNG originate in the Lower 48 states and the other half from Alaska. Continued low levels of LNG imports through the projection period position the United States as a net exporter of LNG by 2016. In general, future U.S. exports of LNG depend on a number of factors that are difficult to anticipate, including the speed and extent of price convergence in global natural gas markets, the extent to which natural gas competes with oil in domestic and international markets, and the pace of natural gas supply growth outside the United States.

Net natural gas imports from Canada decline sharply from 2016 to 2022, then stabilize somewhat before dropping off again in the final years of the projection, as continued growth in domestic production mitigates the need for imports. Even as overall consumption exceeds supply in the United States, some natural gas imports from Canada continue, based on regional supply and demand conditions.

# Petroleum and other liquids consumption

## Petroleum and other liquids consumption outside industrial sector is stagnant or declines

**Figure 93. Consumption of petroleum and other liquids by sector, 1990-2040 (million barrels per day)**



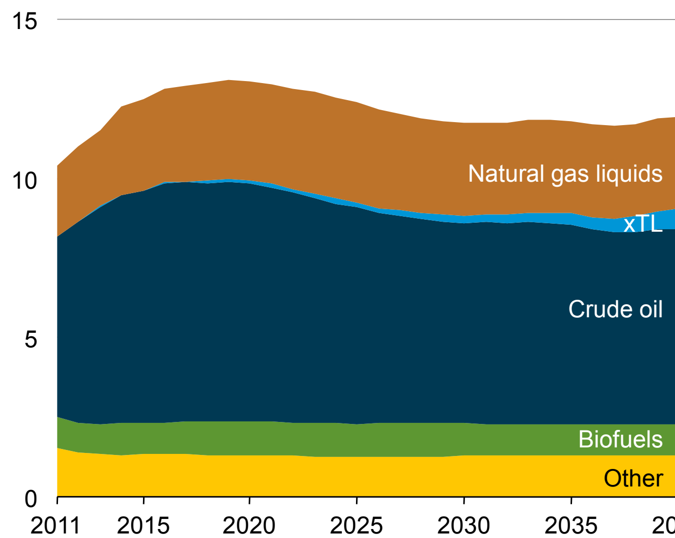

Consumption of petroleum and other liquids peaks at 19.8 million barrels per day in 2019 in the *AEO2013* Reference case and then falls to 18.9 million barrels per day in 2040 (Figure 93). The transportation sector accounts for the largest share of total consumption throughout the projection, although its share falls to 68 percent in 2040 from 72 percent in 2012 as a result of improvements in vehicle efficiency following the incorporation of CAFE standards for both LDVs and HDVs. Consumption of petroleum and other liquids increases in the industrial sector, by 0.6 million barrels per day from 2011 to 2040, but decreases in all the other end-use sectors.

Motor gasoline, ultra-low-sulfur diesel fuel, and jet fuel are the primary transportation fuels, supplemented by biofuels and natural gas. Motor gasoline consumption drops by approximately 1.6 million barrels per day from 2011 to 2040 in the Reference case, while diesel fuel consumption increases from 3.5 million barrels per day in 2011 to 4.3 million in 2040, primarily for use in heavy-duty vehicles. At the same time, natural gas use in heavy-duty vehicles displaces 0.7 million barrels per day of petroleum-based motor fuel in 2040, most of which is diesel.

An increase in consumption of biodiesel and next-generation biofuels [*136*], totaling about 0.4 million barrels per day from 2011 to 2040, is attributable to the EISA2007 RFS mandates. The relative competitiveness of CTL and GTL fuels improves over the projection period as petroleum prices rise. In 2040, CTL and GTL together supply 0.3 million barrels per day of non-petroleum liquids. Both ethanol blending into gasoline and E85 consumption are essentially flat from 2011 through 2040, as a result of declining gasoline consumption and limited penetration of FFVs.

## Crude oil leads initial growth in liquids supply, next-generation liquids grow after 2020

**Figure 94. U.S. production of petroleum and other liquids by source, 2011-2040 (million barrels per day)**



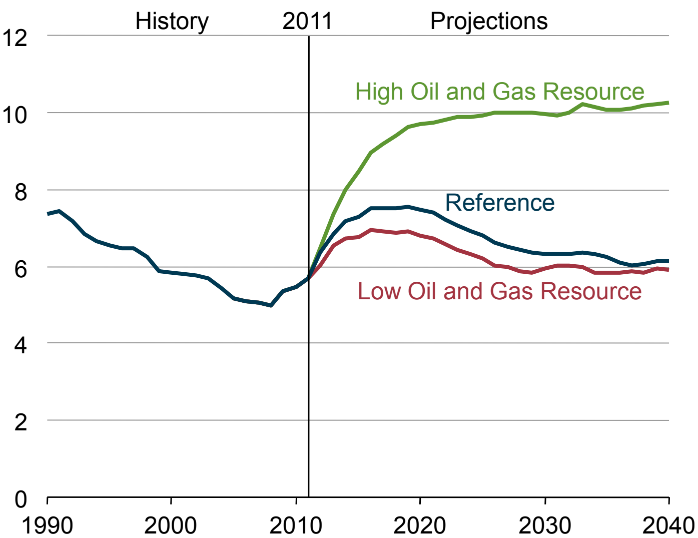

In the *AEO2013* Reference case, total production of petroleum and other liquids grows rapidly in the first decade and then slows in the later years before 2040 (Figure 94). Liquids production increases from 10.4 million barrels per day in 2011 to 13.1 million barrels per day in 2019 primarily as a result of growth in onshore production of crude oil and NGL from tight oil formations (including shale plays).

After 2019, total U.S. production of petroleum and other liquids declines, to 12.0 million barrels per day in 2040, as crude oil production from tight oil plays levels off when less-productive or less-profitable areas are developed. The crude oil share of total domestic liquids production declines to 51 percent in 2040 from a peak of 59 percent in 2016. NGL production also declines, to 2.9 million barrels per day in 2040 from a peak of 3.2 million barrels per day in 2024.

Domestic ethanol production remains relatively flat throughout the projection, as consumption of motor gasoline decreases and the penetration of ethanol in the gasoline pool is slowed by the limited availability of FFVs and retrofitted filling stations. Total biofuel production increases by 0.4 million barrels per day in the projection, as drop-in fuels from biomass enter the market. Other emerging technologies capable of producing liquids—such as xTL [*137*], which includes CTL and GTL technologies—also become economical as more plants are built. In 2040, liquids production from xTL plants totals 0.3 million barrels per day. Investment in xTL technologies is slowed somewhat by high capital costs and the risk that xTL liquids production will not remain price-competitive with crude oil.

## U.S. oil production rates depend on resource availability and advances in technology

**Figure 95. Total U.S. crude oil production in three resource cases, 1990-2040 (million barrels per day)**



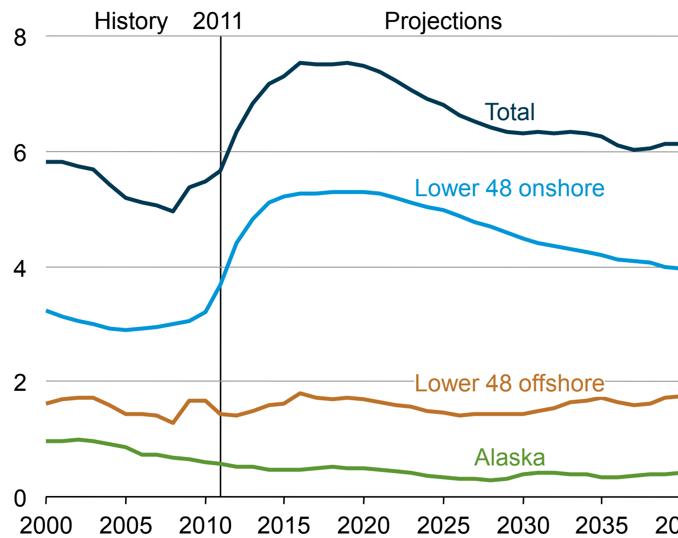

The outlook for domestic crude oil production depends on the production profiles of individual wells over time, the costs of drilling and operating those wells, and the revenues they generate (Figure 95). Every year, EIA reestimates initial production rates and production decline curves, which determine EUR per well and total technically recoverable resources. The underlying resource for the *AEO2013* Reference case is uncertain, particularly as exploration and development of tight oil continue to move into areas with little or no production history. Because many wells drilled in tight formations or shale formations using the latest technologies have less than two years of production history, the impacts of recent technology advances on the estimate of future recovery cannot be fully ascertained.

In the High Oil and Gas Resource case, domestic crude oil production continues to increase through the projection period, to more than 10 million barrels per day in 2040. This case includes: (1) higher estimates of onshore lower 48 tight oil, tight gas, and shale gas resources than in the Reference case, as a result of higher estimated ultimate recovery per well and closer well spacing as additional layers of low-permeability zones are identified and developed; (2) tight oil development in Alaska; and (3) higher estimates of offshore resources in Alaska and the lower 48 states, resulting in more and earlier development of those resources than in the Reference case.

The Low Oil and Gas Resource case considers the impacts of lower estimates of tight oil, tight gas, and shale gas resources than in the Reference case. These two alternative cases provide a framework for examining the impacts of higher and lower domestic supply on energy demand, imports, and prices.

## Lower 48 onshore tight oil development spurs increase in U.S. crude oil production

**Figure 96. Domestic crude oil production by source, 2000-2040 (million barrels per day)**



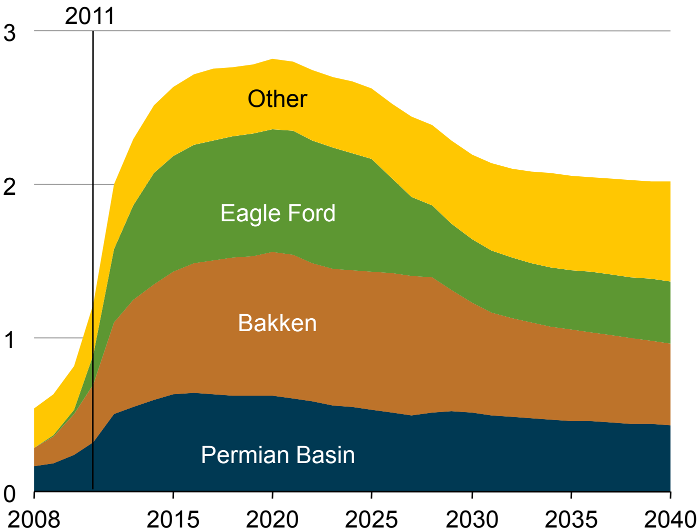

U.S. crude oil production rises through 2016 in the *AEO2013* Reference case, before leveling off at about 7.5 million barrels per day from 2016 through 2020—approximately 1.8 million barrels per day above 2011 volumes (Figure 96). Growth in lower 48 onshore crude oil production results primarily from continued development of tight oil resources, mostly in the Bakken, Eagle Ford, and Permian Basin formations. Tight oil production reaches 2.8 million barrels per day in 2020 and then declines to about 2.0 million barrels per day in 2040, still higher than 2011 levels, as high-productivity sweet spots are depleted. There is uncertainty about the expected peak level of tight oil production, because ongoing exploration, appraisal, and development programs expand operators' knowledge about producing reservoirs and could result in the identification of additional tight oil resources.

Crude oil production using carbon dioxide-enhanced oil recovery ($CO_2$-EOR) increases appreciably after about 2020, when oil prices rise as output from the more profitable tight oil deposits begins declining, and affordable anthropogenic sources of carbon dioxide ($CO_2$) become available. Production plateaus at about 650,000 barrels per day from 2034 to 2040, when production is limited by reservoir quality and $CO_2$ availability. From 2012 through 2040, cumulative crude oil production from $CO_2$-EOR projects is 4.7 billion barrels.

Lower 48 offshore oil production varies between 1.4 and 1.8 million barrels per day over the projection period. Toward the end of the projection the pace of exploration and production activity quickens, and new large development projects, associated predominantly with discoveries in the deepwater and ultra-deepwater portions of the Gulf of Mexico, are brought on stream. New offshore oil production in the Alaska North Slope areas partially offsets the decline in production from North Slope onshore fields.

## Tight oil formations account for a significant portion of total U.S. production

### Figure 97. Total U.S. tight oil production by geologic formation, 2008-2040 (million barrels per day)




The term tight oil does not have a specific technical, scientific, or geologic definition. Tight oil is an industry convention that generally refers to oil produced from very-low-permeability [*138*] shale, sandstone, and carbonate formations. Some of these geologic formations have been producing low volumes of oil for many decades in limited portions of the formation.

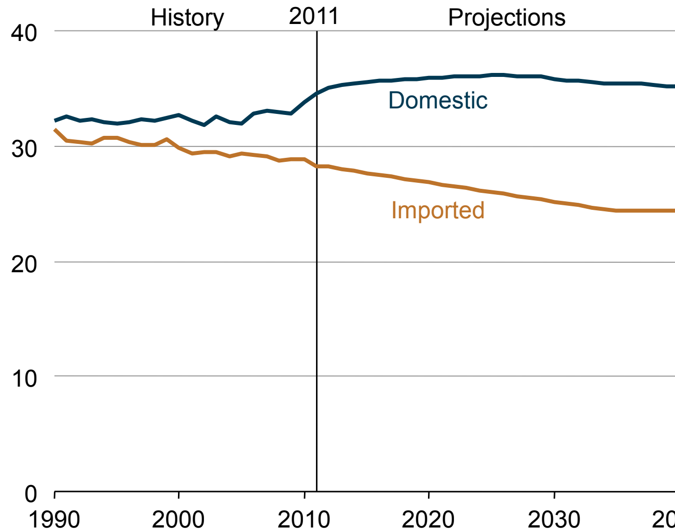
In the *AEO2013* Reference Case, about 25.3 billion barrels of tight oil are produced cumulatively from 2012 through 2040. The Bakken-Three Forks formations contribute 32 percent of this production, while the Eagle Ford and Permian Basin formations respectively account for 24 and 22 percent of the cumulative tight oil production. The remaining 22 percent of cumulative tight oil production comes from other formations, including but not limited to the Austin Chalk, Niobrara, Monterey, and Woodford formations. Permian Basin tight oil production comes primarily from the Spraberry, Wolfcamp, and Avalon/Bone Spring formations, which are listed here relative to their contribution to cumulative production.

After 2021, tight oil production declines in the *AEO2013* Reference case (Figure 97), as the depleted wells located in high-productivity areas are replaced by lower-productivity wells located elsewhere in the formations. In 2040, tight oil production is 2.0 million barrels per day, about 33 percent of total U.S. oil production. Because tight oil wells exhibit high initial production rates followed by slowly declining production rates in later years, production declines rather slowly at the end of the projection period.

Tight oil development is still at an early stage, and the outlook is highly uncertain. Alternative cases, including ones in which tight oil production is significantly above the Reference case projection, are examined in the “Issues in focus” section of this report (see “Petroleum import dependence in a range of cases”).

## Domestic production of tight oil leads to lower imports of light sweet crude oil

### Figure 98. API gravity of U.S. domestic and imported crude oil supplies, 1990-2040 (degrees)



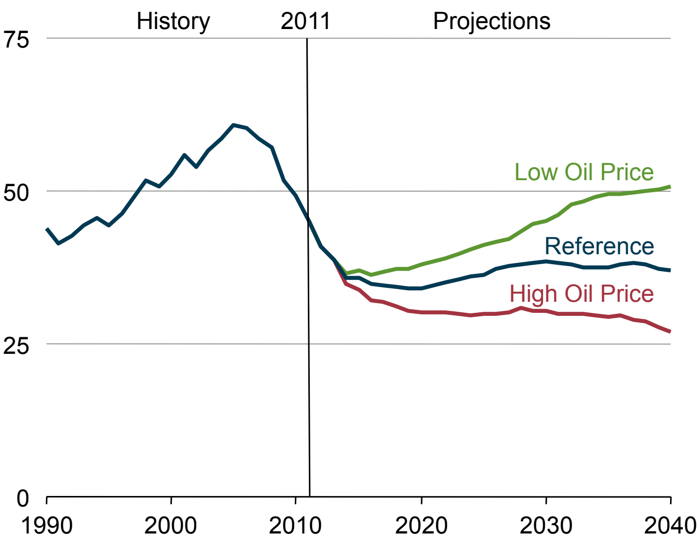

API gravity is a measure of the specific gravity, or relative density, of a liquid, as defined by the American Petroleum Institute (API). It is expressed in degrees, where a higher number indicates lower density. Refineries generally process a mix of crude oils with a range of API gravities in order to optimize refinery operations. Over the past 15 years, the API gravity of crude oil processed in U.S. refineries has averaged between 30 and 31 degrees. As U.S. refiners run more domestic light crude produced from tight formations, they need less imported light oil crude to maintain an optimal API gravity. With increasing U.S. production of light crude oil in the Reference case, the average API gravity of crude oil imports declines (Figure 98).

In the *AEO2013* Reference case, the trend toward increasing imports of heavier crude oils continues through 2035 before stabilizing [*139*]. The increase in demand for diesel fuel in the projection, from 3.5 to 4.3 million barrels per day, leads to an increase in distillate and gas oil hydrocracking capacity (which increases diesel production capability) from 1.6 to 3.0 million barrels per day from 2011 to 2040.

The large increase in domestic production of light crude oil and the increase in imports of heavier crude oils have prompted significant investments in crude midstream infrastructure, including pipelines that will bring higher quantities of light sweet crudes to petroleum refineries along the U.S. Gulf Coast. In addition, significant investments are being made to move crude oil to refineries by rail. The Reference case assumes that sufficient infrastructure investments will be made through 2040 to move both light and heavy crude oils.

## Increasing U.S. supply results in decreasing net imports of petroleum and other liquids

**Figure 99. Net import share of U.S. petroleum and other liquids consumption in three oil price cases, 1990-2040 (percent)**



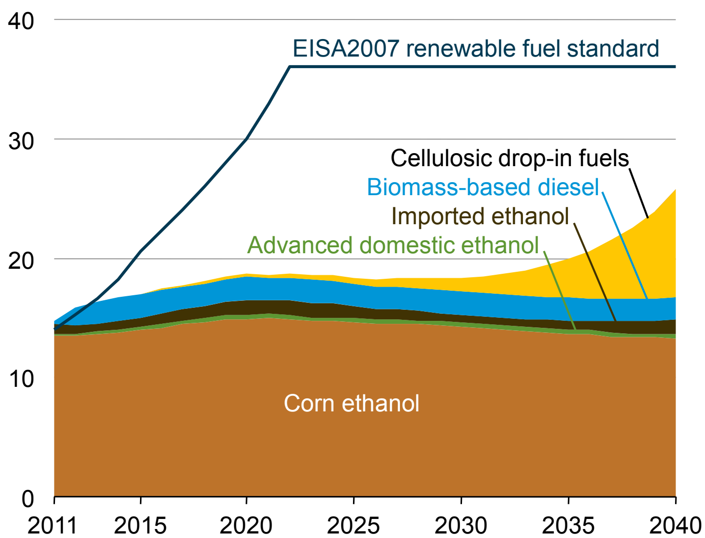

The net import share of U.S. petroleum and other liquids consumption (including crude oil, petroleum liquids, and liquids derived from nonpetroleum sources) grew steadily from the mid-1980s to 2005 but has fallen in every year since then. In the *AEO2013* Reference and High Oil Price cases, U.S. imports of petroleum and other liquids decline through 2020, while still providing approximately one-third of total U.S. supply. As a result of increased production of domestic petroleum, primarily from tight oil formations, and a moderation of demand growth with tightening fuel efficiency standards, the import share of total supply declines. Domestic production of crude oil from tight oil formations, primarily from the Williston, Western Gulf, and Permian basins, increases by about 1.5 million barrels per day from 2011 to 2016 in both the Reference and High Oil Price cases.

The net import share of U.S. petroleum and other liquids consumption, which fell from 60 percent in 2005 to 45 percent in 2011, continues to decline in the Reference case, with the net import share falling to 34 percent in 2019 before increasing to 37 percent in 2040 (Figure 99). In the High Oil Price case, the net import share falls to an even lower 27 percent in 2040. In the Low Oil Price case, the net import share remains relatively flat in the near term but rises to 51 percent in 2040, as domestic demand increases, and imports become less expensive than domestically produced crude oil.

As a result of increased domestic production and slow growth in consumption, the United States becomes a net exporter of petroleum products, with net exports in the Reference case increasing from 0.3 million barrels per day in 2011 to 0.7 million barrels per day in 2040. In the High Oil Price case, net exports of petroleum products increase to 1.2 million barrels per day in 2040.

## U.S. consumption of cellulosic biofuels falls short of EISA2007 Renewable Fuels Standard target

**Figure 100. EISA2007 RFS credits earned in selected years, 2011-2040 (billion credits)**



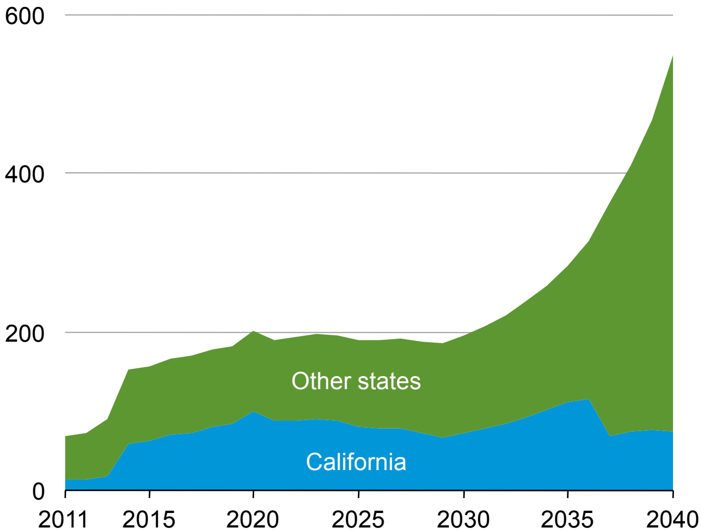

Biofuel consumption grows in the *AEO2013* Reference case but falls well short of the EISA2007 RFS target [*140*] of 36 billion gallons ethanol equivalent in 2022 (Figure 100), largely because of a decline in gasoline consumption as a result of newly enacted CAFE standards and updated expectations for sales of vehicles capable of using E85. From 2011 to 2022, demand for motor gasoline ethanol blends (E10 and E15) falls from 8.7 million barrels to 8.1 million barrels per day.

Because the current and projected vehicle fleets are not equipped to use ethanol's increased octane relative to gasoline, they cannot offset its lower energy density. As a result, the wholesale price of ethanol does not exceed two-thirds of the wholesale gasoline price. This reflects the energy-equivalent value of ethanol and would be the equilibrium price in periods with significant market penetration of blends with high ethanol content, such as E85. The RFS program does not provide sufficient incentives to promote significant new ethanol capacity in this pricing environment. Also during the projection period, consumption of biomass-based diesel levels off in the Reference case after growing to meet the current RFS target of 1.9 billion gallons ethanol equivalent in 2013.

Ethanol consumption falls from 16.4 billion gallons in 2022 to 14.9 billion gallons in 2040 in the *AEO2013* Reference case, as gasoline demand continues to drop and E85 consumption levels off. However, domestic consumption of drop-in cellulosic biofuels grows from 0.3 billion gallons to 9.0 billion gallons ethanol equivalent per year from 2011 to 2040, as rising oil prices lead to price increases for diesel fuel, heating oil, and jet fuel, while production costs for biofuel technologies fall.

## Renewable Fuel Standard and California Low Carbon Fuel Standard boost the use of new fuels

**Figure 101. Consumption of advanced renewable fuels, 2011-2040 (thousand barrels per day)**



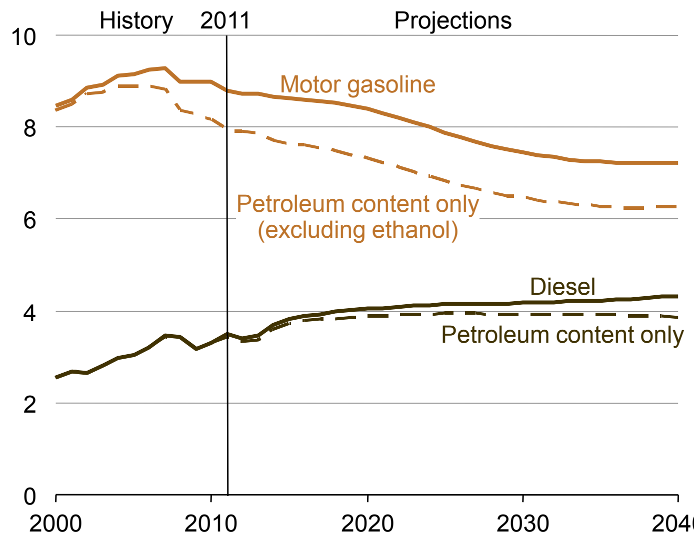

In response to the RFS implemented nationwide and the California Low Carbon Fuel Standard (LCFS), consumption of advanced biofuels increases in the *AEO2013* Reference case (Figure 101). As defined in the RFS, the advanced renewable fuels category consists of fuels that achieve a 50-percent reduction in life-cycle GHG emissions (including indirect changes in land use). The advanced fuel category includes ethanol produced from sugar cane (but not from corn starch), biodiesel, renewable diesel, and cellulosic biofuels [*141*]. California uses a large fraction of the total advanced renewable fuel pool in the early years of the projection.

Under the California LCFS, each fuel is considered individually according to its carbon intensity relative to the LCFS target. In general, fuels that qualify as advanced renewable fuels under the RFS have low carbon intensities for the purposes of the California LCFS, but the reverse is not always true.

Starting about 2030, production of cellulosic drop-in biofuels ramps up in California and other states. Outside California, production and consumption of cellulosic biofuels increases rapidly enough to cause a decline in California's fraction of the total advanced biofuels market. Starting in about 2035, corn ethanol with low carbon intensity begins to displace imported sugar cane ethanol in California.

## Efficiency standards shift consumption from motor gasoline to diesel fuel

**Figure 102. U.S. motor gasoline and diesel fuel consumption, 2000-2040 (million barrels per day)**



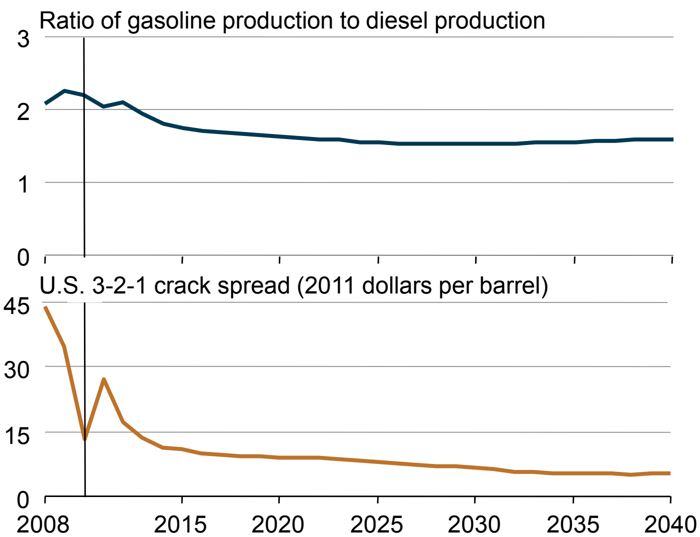

Based on NHTSA estimates, more stringent efficiency standards for LDVs will require new LDVs to average approximately 49 mpg in 2025, in addition to regulations requiring increased use of ethanol. The combination contributes to a decline in consumption of motor gasoline and an increase in consumption of diesel fuel and ethanol in the *AEO2013* Reference case. Motor gasoline consumption falls despite an increase in VMT by LDVs over the projection period.

The decrease in gasoline consumption, combined with growth in diesel consumption, leads to a shift in refinery outputs and investments. Motor gasoline consumption and diesel fuel consumption trend in opposite directions in the Reference case: consumption of diesel fuel increases by approximately 0.8 million barrels per day from 2011 to 2040, while finished motor gasoline consumption falls by 1.6 million barrels per day (Figure 102). Although some smaller and less-integrated refineries begin to idle capacity as a result of higher costs, new refinery projects focus on shifting production from gasoline to distillate fuels to meet growing demand for diesel.

In the Reference case, as a result of refinery economics and slower growth in domestic demand, no new petroleum refinery capacity expansions are built during the projection period besides those already under construction. Further, approximately 200,000 barrels per day of capacity is retired, beginning in 2012. In addition to meeting domestic demand, refineries continue exporting finished products to international markets throughout the projection period. From 2014 to 2017 gross exports of finished products increase to more than 3.0 million barrels per day for the first time, and they remain near that level through 2040. Further, the United States, which became a net exporter of finished products in 2011, remains a net exporter through 2040 in the Reference case.

## Shifts in demand for liquid fuels change petroleum refinery yields and crack spreads

**Figure 103. U.S. refinery gasoline-to-diesel production ratio and crack spread, 2008-2040**

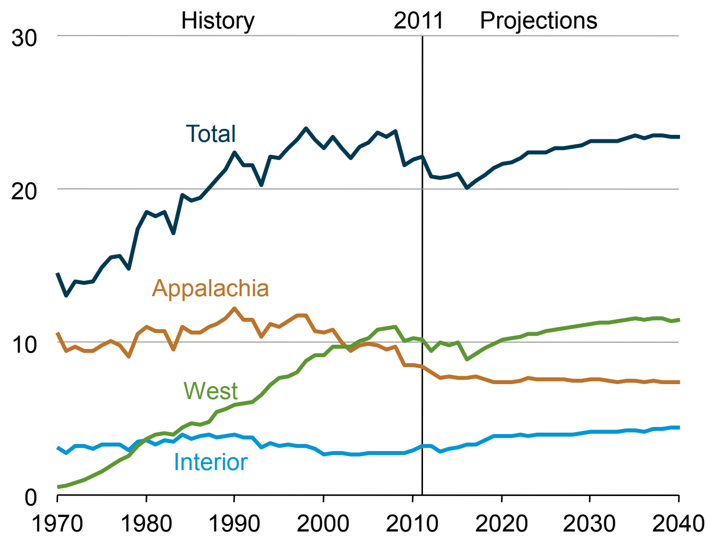



The transition to lower gasoline and higher diesel production has a significant effect on petroleum refinery operations. In the *AEO2013* Reference case, the ratio of gasoline to diesel production at petroleum refineries declines from 2.1 in 2012 to 1.6 after 2035 (Figure 103). In response to the drop in gasoline demand, refinery utilization of fluid catalytic cracking (FCC) units drops from 83 percent in 2011 to about 62 percent in 2040. In contrast, with diesel production increasing, installed distillate and gas oil hydrocracking capacity grows from about 1.8 million barrels per day in 2012 to 3.0 million barrels per day in 2040. The increase in installed hydrocracking capacity implies a shifting of FCC feeds to hydrocrackers in order to maximize diesel production.

Refinery profitability is a function of crude input costs, processing costs, and market prices for the end products. Profitability often is estimated from the crack spread, which is the difference between the price of crude oil and the price of distilled products, typically gasoline and distillate fuel. The 3-2-1 crack spread estimates the profitability of processing 3 barrels of crude oil to produce 2 barrels of gasoline and 1 barrel of distillate. In the Reference case, the 3-2-1 crack spread (based on Brent) declines steadily from $17 per barrel (2011 dollars) in 2012 to about $5 per barrel in 2040. This represents a gross margin for the refinery, based on Brent crude prices and average gasoline and diesel prices in the United States. In the current environment, this gross margin would drop by the differential between the prices of Brent and Gulf Coast light crudes. To relate the gross margin to refinery profitability, operating costs for specific refineries would also have to be deducted. The decline in the 3-2-1 crack spread slows after 2016. As product demands shift, petroleum refineries may alter the ratio of gasoline to diesel production. A 5-3-2 crack spread would be more consistent with the 1.6 gasoline-to-diesel production ratio after 2035.

## Early declines in coal production are followed by growth after 2016

**Figure 104. Coal production by region, 1970-2040 (quadrillion Btu)**



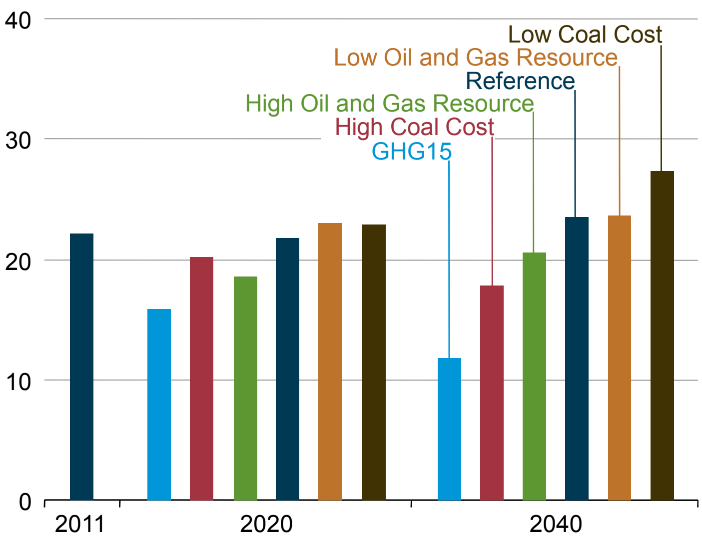

U.S. coal production largely follows the trend of domestic coal consumption, but increasingly it is influenced by coal exports. In the near term, the combination of relatively low natural gas prices and high coal prices, the lack of a strong recovery in electricity demand, and increasing generation of electricity from renewables suppress domestic coal consumption. In addition, new requirements to control emissions of mercury and acid gases result in the retirement of some coal-fired generating capacity, contributing to a near-term decline in coal demand. After 2016, coal production in the Reference case increases by an average of 0.6 percent per year through 2040 (Figure 104), as a result of growing coal exports and increasing use of coal in the electricity sector as electricity demand grows and natural gas prices rise.

On a regional basis, the Interior and Western regions show similar growth in production, while Appalachian output declines. Following some early setbacks, Western coal production increases steadily through 2035 before leveling off. Coal from the West satisfies much of the additional need for fuel at coal-fired power plants, and it is also boosted by increasing exports and production of synthetic liquids. Coal production in the Interior region, which has trended downward slightly since the early 1990s, reaches new highs in the *AEO2013* Reference case. Additional production from the region originates mostly from mines tapping into the substantial reserves of bituminous coal in Illinois, Indiana, and western Kentucky. Appalachian coal production declines substantially from current levels, as coal produced from the extensively mined, higher-cost reserves of Central Appalachia is supplanted by lower-cost coal from other regions. An expected increase in production from the northern part of the Appalachian basin moderates the overall decline.

# Coal production

## Outlook for U.S. coal production is affected by fuel price uncertainties

**Figure 105. U.S. total coal production in six cases, 2011, 2020, and 2040 (quadrillion Btu)**

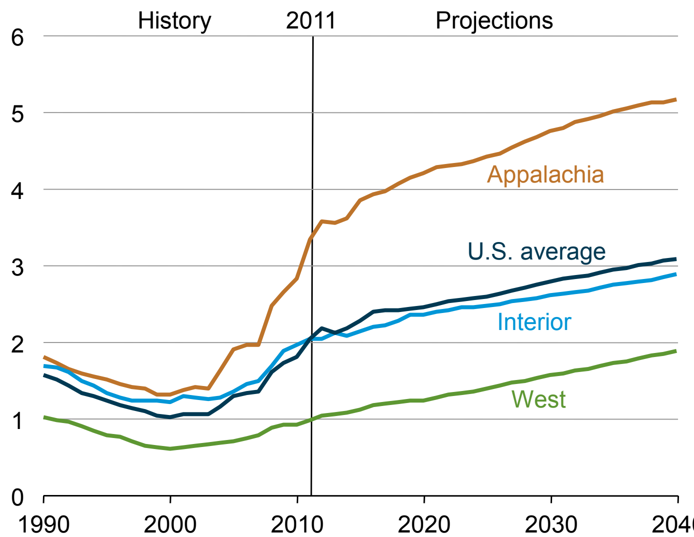



U.S. coal production varies across the *AEO2013* cases, reflecting the effects of different assumptions about the costs of producing and transporting coal, the outlook for natural gas prices, and possible controls on GHG emissions (Figure 105). In general, assumptions that reduce the competitiveness of coal versus natural gas result in less coal production: in the High Coal Cost case as a result of significantly higher estimated costs to mine and transport coal, and in the High Oil and Gas Resource case as a result of lower natural gas production costs than in the Reference case. Similarly, actions to reduce GHG emissions can reduce the competeviness of coal, because its high carbon content can translate into a price penalty, in the form of GHG fees, relative to other fuels. Conversely, lower coal prices in the Low Coal Cost case and higher natural gas prices in the Low Oil and Gas Resource case improve the competitiveness of coal and lead to higher levels of coal production.

Of the cases shown in Figure 105, the most substantial decline in U.S. coal production occurs in the GHG15 case, where an economy-wide $CO_2$ emissions price that rises to $53 per metric ton in 2040 leads to a 50-percent drop in coal production from the Reference case level in 2040. Across the remaining cases, variations range from 15 percent lower to 6 percent higher than production in the Reference case in 2020; and by 2040, as the gap in coal prices widens over time, the range of differences increases to 24 percent below and 16 percent above the Reference case in the High Coal Cost and Low Coal Cost cases, respectively. In two additional GHG cases developed for *AEO2013* (not shown in Figure 105), economy-wide $CO_2$ allowance fees are assumed to increase to $36 per metric ton in the GHG10 case and $89 per metric ton in the GHG25 case in 2040, resulting in total coal production in 2040 that is 25 percent lower and 72 percent lower, respectively, than in the Reference case.

## Expected declines in mining productivity lead to further increases in average minemouth prices

**Figure 106. Average annual minemouth coal prices by region, 1990-2040 (2011 dollars per million Btu)**




In the *AEO2013* Reference case, the average real minemouth price for U.S. coal increases by 1.4 percent per year, from $2.04 per million Btu in 2011 to $3.08 in 2040, continuing the upward trend in coal prices that began in 2000 (Figure 106). A key factor underlying the higher coal prices in the projection is an expectation that coal mining productivity will continue to decline, but at slower rates than during the 2000s.

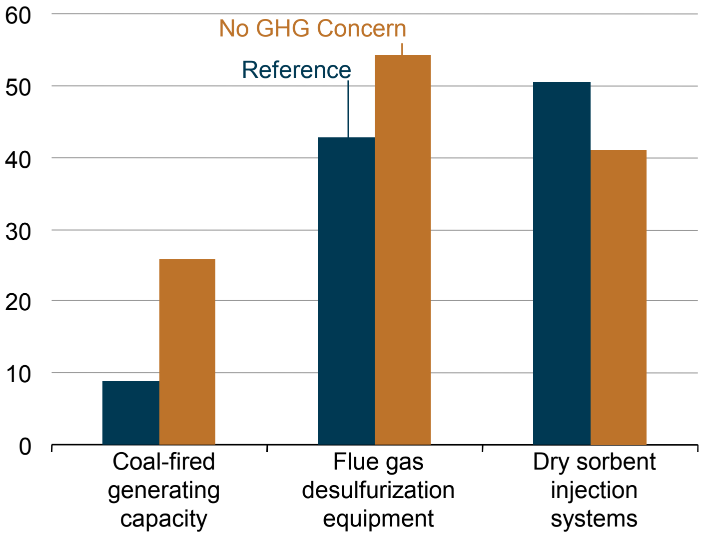
In the Appalachian region, the average minemouth coal price increases by 1.5 percent per year from 2011 to 2040. In addition to continued declines in coal mining productivity, the higher price outlook for the Appalachian region reflects a shift to higher-value coking coal, resulting from the combination of growing exports of coking coal and declining shipments of steam/thermal coal to domestic markets. Recent increases in the average price of Appalachian coal, from $1.31 per million Btu in 2000 to $3.33 per million Btu in 2011, in part as a result of significant declines in mining productivity over the past decade, have substantially reduced the competitiveness of Appalachian coal with coal from other regions.

In the Western and Interior coal supply regions, declines in mining productivity, combined with increasing production, lead to increases in the real minemouth price of coal, averaging 2.3 percent per year for the Western region and 1.2 percent per year for the Interior region from 2011 to 2040.

In two alternative coal cost cases developed for *AEO2013*, the average U.S. minemouth coal price in 2040 is as low as $1.70 per million Btu in the Low Coal Cost case (45 percent below the Reference case) and as high as $6.20 per million Btu in the High Coal Cost case (101 percent higher than in the Reference case). Results for the two cases, which are based on different assumptions about mining productivity, labor costs, mine equipment costs, and coal transportation rates, are provided in Appendix D.

## Concerns about future GHG policies affect builds of new coal-fired generating capacity

**Figure 107. Cumulative coal-fired generating capacity additions and environmental retrofits in two cases, 2012-2040 (gigawatts)**



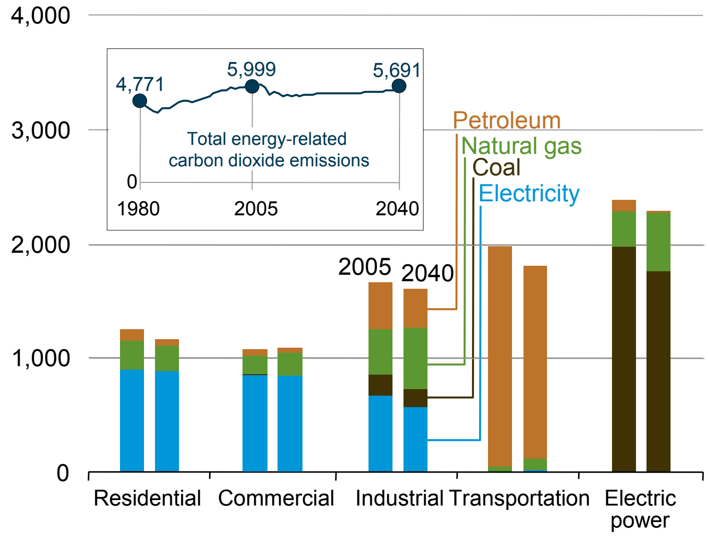

In the *AEO2013* Reference case, the cost of capital for investments in GHG-intensive technologies is increased by 3 percentage points, primarily to reflect the behavior of electricity generators who must evaluate long-term investments across a range of generating technologies in an environment where future restrictions of GHG emissions are likely. The higher cost of capital is used to estimate the costs for new coal-fired power plants without carbon capture and storage (CCS) and for capital investment projects at existing coal-fired power plants (excluding CCS). The No GHG Concern case illustrates the potential impact on energy investments when the cost of capital is not increased for GHG-intensive technologies.

In the No GHG Concern case, a lower cost of capital leads to the addition of 26 gigawatts of new coal-fired capacity from 2012 to 2040, up from 9 gigawatts in the Reference case (Figure 107). Nearly all projected builds in the Reference case are plants already under construction. As a result, additions of natural gas, nuclear, and renewable generating capacity all are slightly lower in the No GHG Concern case than in the Reference case.

In addition to affecting builds of new generating capacity, removing the premium for the cost of capital also influences capital investment projects at existing coal-fired power plants. In the No GHG Concern case, the lower cost of capital results in some additional retrofits of flue gas desulfurization (FGD) equipment relative to the Reference case, and fewer retrofits of dry sorbent injection (DSI) systems, which are a less capital-intensive option than FGD for controlling emissions of acid gases. To comply with the requirements specified in the Mercury and Air Toxics Standards (MATS), the *AEO2013* projections assume that coal-fired power plants must be equipped with either FGD equipment or DSI systems with full fabric filters.

## Energy-related carbon dioxide emissions remain below their 2005 level through 2040

**Figure 108. U.S. energy-related carbon dioxide emissions by sector and fuel, 2005 and 2040 (million metric tons)**




On average, energy-related $CO_2$ emissions in the *AEO2013* Reference case decline by 0.2 percent per year from 2005 to 2040, as compared with an average increase of 0.9 percent per year from 1980 to 2005. Reasons for the decline include: an expected slow and extended recovery from the recession of 2007-2009; growing use of renewable technologies and fuels; automobile efficiency improvements; slower growth in electricity demand; and more use of natural gas, which is less carbon-intensive than other fossil fuels. In the Reference case, energy-related $CO_2$ emissions in 2020 are 9.1 percent below their 2005 level. Energy-related $CO_2$ emissions total 5,691 million metric tons in 2040, or 308 million metric tons (5.1 percent) below their 2005 level (Figure 108).

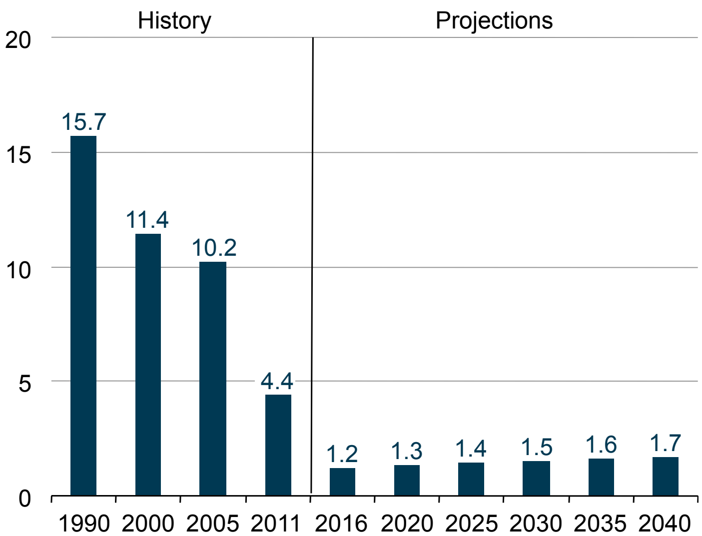
Petroleum remains the largest source of U.S. energy-related $CO_2$ emissions in the projection, but its share falls to 38 percent in 2040 from 44 percent in 2005. $CO_2$ emissions from petroleum use, mainly in the transportation sector, are 448 million metric tons below their 2005 level in 2040.

Emissions from coal, the second-largest source of energy-related $CO_2$ emissions, are 246 million metric tons below the 2005 level in 2040 in the Reference case, and their share of total energy-related $CO_2$ emissions declines from 36 percent in 2005 to 34 percent in 2040. The natural gas share of total $CO_2$ emissions increases from 20 percent in 2005 to 28 percent in 2040, as the use of natural gas to fuel electricity generation and industrial applications increases. Emissions levels are sensitive to assumptions about economic growth, fuel prices, technology costs, and policies that are explored in many of the alternative cases completed for *AEO2013*.

# Emissions from energy use

## Power plant emissions of sulfur dioxide are reduced by further environmental controls

**Figure 109. Sulfur dioxide emissions from electricity generation, 1990-2040 (million short tons)**



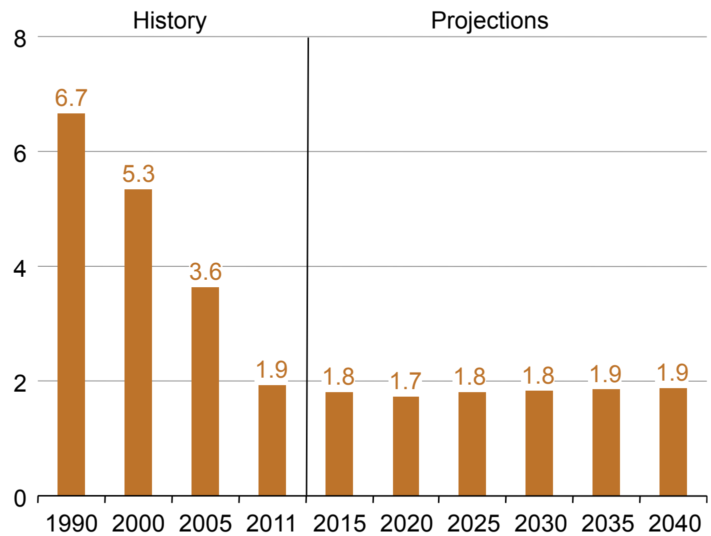

In the *AEO2013* Reference case, sulfur dioxide ($SO_2$) emissions from the U.S. electric power sector fall from 4.4 million short tons in 2011 to a range between 1.2 and 1.7 million short tons in the 2016-2040 projection period. The reduction occurs in response to the MATS [*142*]. Although $SO_2$ is not directly regulated by the MATS, the reductions are achieved as a result of acid gas limits that lead to the installation of FGD units or DSI systems, which also remove $SO_2$. *AEO2013* assumes that, in order to comply with MATS, coal-fired power plants must have one of the two technologies installed by 2016. Both technologies, which are used to reduce acid gas emissions regulated under MATS, also reduce $SO_2$ emissions.

EIA assumes a 95-percent $SO_2$ removal efficiency for FGD units and a 70-percent $SO_2$ removal efficiency for DSI systems paired with baghouse fabric filters. *AEO2013* also assumes that a baghouse fabric filter is required for all coal-fired plants in order to comply with the nonmercury metal emissions limits set forth by MATS [*143*, *144*].

From 2011 to 2040, approximately 43 gigawatts of coal-fired capacity is retrofitted with FGD units in the Reference case, and another 50 gigawatts is retrofitted with DSI systems. In 2016, all operating coal-fired generation units larger than 25 megawatts are assumed to have either DSI or FGD systems installed. After a 73-percent decrease from 2011 to 2016, $SO_2$ emissions increase slowly from 2016 to 2040 (Figure 109) as total electricity generation from coal-fired power plants increases. The increase is relatively small, however, because overall growth in generation from coal is slow, and the required installations of FGD and DSI equipment limit $SO_2$ emissions from plants in operation.

## Nitrogen oxides emissions show little change from 2011 to 2040 in the Reference case

**Figure 110. Nitrogen oxides emissions from electricity generation, 1990-2040 (million short tons)**




Annual emissions of nitrogen oxides ($NO_X$) from the electric power sector, which totaled 1.9 million short tons in 2011, range between 1.6 and 2.1 million short tons from 2011 to 2040 (Figure 110). Annual $NO_X$ emissions from electricity generation dropped by 47 percent from 2005 to 2011 as a result of the implementation of the Clean Air Interstate Rule (CAIR), which led to year-round operation of advanced pollution control equipment (that under the $NO_X$ budget program operated during the summer season only) and to additional installations of $NO_X$ pollution control equipment.

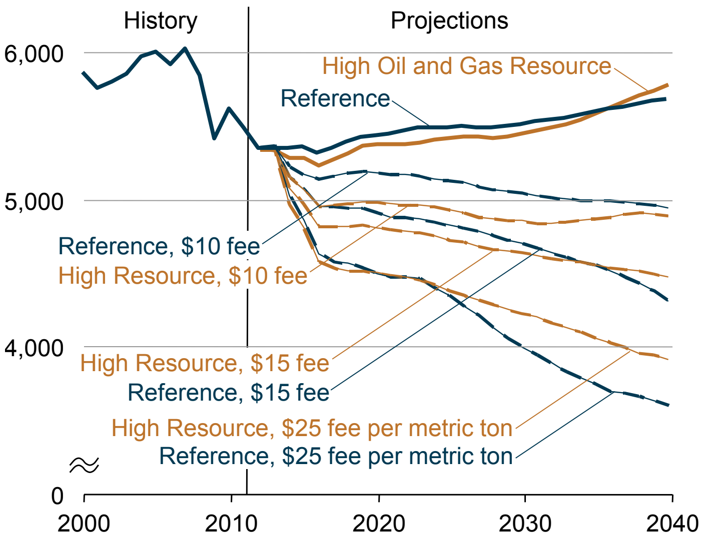
In the *AEO2013* Reference case, annual $NO_X$ emissions in 2040 are 4 percent below the 2011 level, despite a 6-percent increase in annual electricity generation from coal-fired power plants over the period. The drop in emissions is primarily a result of CAIR, which established an annual cap-and-trade program for $NO_X$ emissions in 25 states and the District of Columbia. A slight rise in $NO_X$ emissions after 2020 corresponds to a projected recovery in coal-fired generation.

MATS does not have a direct effect on $NO_X$ emissions, because none of the potential technologies required to comply with MATS has a significant impact on $NO_X$ emissions. However, because MATS contributes to a reduction in coal-fired generation nationwide, it indirectly reduces $NO_X$ emissions from the power sector in states not affected by CAIR.

From 2011 to 2040, 15.4 gigawatts of coal-fired capacity is retrofitted with $NO_X$ controls in the *AEO2013* Reference case. Coal-fired power plants can be retrofitted with three types of $NO_X$ control technologies: selective catalytic reduction (SCR), selective noncatalytic reduction (SNCR), or low-$NO_X$ burners, depending on the specific characteristics of the plant, including boiler configuration and the type of coal used. SCRs make up 90 percent of the $NO_X$ controls installed in the Reference case, SNCRs 5 percent, and low-$NO_X$ burners 5 percent.

## Energy-related carbon dioxide emissions are sensitive to potential policy changes

### Figure 111. Energy-related carbon dioxide emissions in two cases with three levels of emissions fees, 2000-2040 (million metric tons)



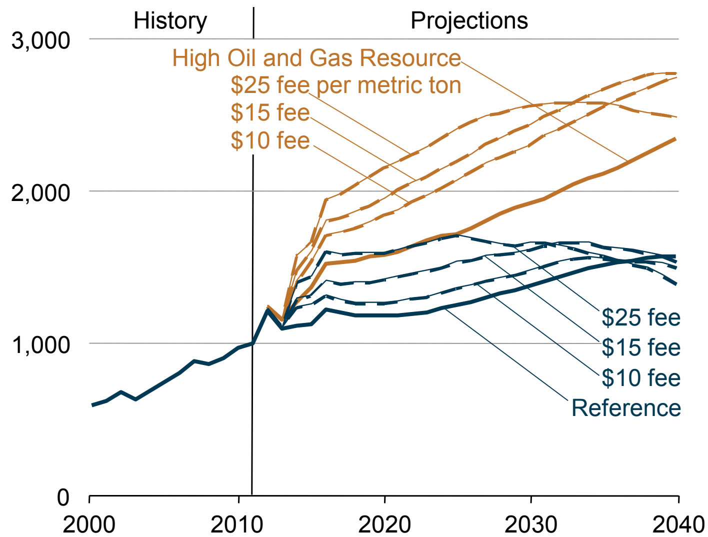

Although the *AEO2013* Reference case assumes that current laws and regulations remain in effect through 2040, the potential impacts of a future fee on $CO_2$ emissions are examined in three carbon-fee cases, starting at $10, $15, and $25 per metric ton $CO_2$ in 2014 and rising by 5 percent per year annually thereafter. The three fee cases were combined with the Reference case and also, because of uncertainty about the growing role of natural gas in the U.S. energy landscape and how it might affect efforts to reduce GHG emissions, with the High Oil and Gas Resource case (Figure 111).

Emissions fees would have a significant impact on U.S. energy-related $CO_2$ emissions. They would encourage all energy producers and consumers to shift to lower-carbon or zero-carbon energy sources. Relative to 2005 emissions levels, energy-related $CO_2$ emissions are 14 percent, 19 percent, and 28 percent lower in 2025 in the $10, $15, and $25 fee cases using Reference case resources, respectively, and 17 percent, 28 percent, and 40 percent lower in 2040. When combined with High Oil and Gas Resource assumptions, the $CO_2$ fees tend to lead to slightly greater emissions reductions in the near term and smaller reductions in the long term.

The alternative assumptions about natural gas resources have only small impacts on energy-related $CO_2$ emissions in all the cases except the $25 fee cases. Although more abundant and less expensive natural gas in the High Oil and Gas Resource cases does lead to less coal use and more natural gas use, it also reduces the use of renewable and nuclear fuels and increases energy consumption overall. In the long run, the emissions reductions achieved by shifting from coal to natural gas are offset by the impacts of reduced use of renewables and nuclear power for electricity generation, and by higher overall levels of energy consumption.

## Carbon dioxide fee cases generally increase the use of natural gas for electricity generation

### Figure 112. Natural gas-fired electricity generation in six $CO_2$ fee cases, 2000-2040 (billion kilowatthours)




The role of natural gas in the $CO_2$ fee cases varies widely over time and, in addition, over the range of assumptions about natural gas resources. When $CO_2$ fees are assumed to be introduced in 2014, natural gas-fired generation increases sharply. The role of natural gas in the $CO_2$ fee cases begins declining between 2025 and 2030, however, as power companies bring more new nuclear and renewable plants on line (Figure 112).

After accounting for about 50 percent of all U.S. electricity generation for many years, coal's share has declined over the past few years because of growing competition from efficient natural gas-fired plants with access to low-cost natural gas. In the Reference case, the share of generation accounted for by coal falls from 42 percent in 2011 to 38 percent in 2025 and 35 percent in 2040. Coal's share falls even further in the $CO_2$ fee cases, to a range between 6 percent and 31 percent in 2025 and between 1 percent and 24 percent in 2040.

As the fee for $CO_2$ emissions increases over time, power companies reduce their use of coal and increase their use of nuclear power, renewables, and natural gas. The nuclear and renewable shares of total generation increase in most of the $CO_2$ fee cases, particularly in the later years of the projections. In the Reference case, nuclear generation accounts for 20 percent of the total in 2025 and 17 percent in 2040. In the $CO_2$ fee cases, the nuclear share varies from 20 to 24 percent in 2025 and 18 to 37 percent in 2040. The renewable share of total generation in 2025 is 14 percent in the Reference case, increasing to 16 percent in 2040. In the $CO_2$ fee cases the renewable share is generally higher, between 15 percent and 21 percent in 2025 and between 17 percent and 31 percent in 2040.

# Endnotes for Market trends

**Links current as of March 2013**

124. 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.
125. These expenditures relative to GDP are not the energy-share of GDP, since expenditures include energy as an intermediate product. The energy-share of GDP corresponds to the share of value added due to domestic energy-producing sectors, which would exclude the value of energy as an intermediate product.
126. S.C. Davis, S.W. Diegel, and R.G. Boundy, *Transportation Energy Databook: Edition 31*, ORNL-6987 (Oak Ridge, TN: July 2012), Chapter 2, Table 2.1, "U.S. Consumption of Total Energy by End-Use Sector, 1973-2011."
127. S.C. Davis, S.W. Diegel, and R.G. Boundy, *Transportation Energy Databook: Edition 31*, ORNL-6987 (Oak Ridge, TN: July 2012), Chapter 4, Table 4.6, "New Retail Sales of Trucks 10,000 Pounds GVWR and Less in the United States, 1970-2011."
128. U.S. Department of Transportation, National Highway Safety Administration, "Summary of Fuel Economy Performance" (Washington, DC: October 2012), http://www.nhtsa.gov/staticfiles/rulemaking/pdf/cafe/Oct2012_Summary_Report.pdf.
129. U.S. Environmental Protection Agency and National Highway Traffic Safety Administration, "Light-Duty Vehicle Greenhouse Gas Emission Standards and Corporate Average Fuel Economy Standards; Final Rule," *Federal Register*, Vol. 75, No. 88 (Washington, DC: May 7, 2010), https://www.federalregister.gov/articles/2010/05/07/2010-8159/light-duty-vehicle-greenhouse-gas-emission-standards-and-corporate-average-fuel-economy-standards.
130. U.S. Environmental Protection Agency and National Highway Traffic Safety Administration, "2017 and Later Model Year Light-Duty Vehicle Greenhouse Gas Emissions and Corporate Average Fuel Economy Standards; Final Rule," *Federal Register*, Vol. 77, No. 199 (Washington, DC: October 15, 2012), https://www.federalregister.gov/articles/2012/10/15/2012-21972/2017-and-later-model-year-light-duty-vehicle-greenhouse-gas-emissions-and-corporate-average-fuel.
131. Light-duty vehicle fuel economy includes alternative-fuel vehicles and banked credits towards compliance.
132. 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.
133. Unless otherwise noted, the term capacity in the discussion of electricity generation indicates utility, nonutility, and CHP capacity.
134. Costs are for the electric power sector only.
135. The levelized costs reflect the average of regional costs. For detailed discussion of levelized costs, see U.S. Energy Information Administration, "Levelized Cost of New Generation Resources in the *Annual Energy Outlook 2013*," http://www.eia.gov/forecasts/aeo/electricity_generation.cfm.
136. Next-generation biofuels include pyrolysis oils, biomass-derived Fisher-Tropsch liquids, and renewable feedstocks used for on-site production of diesel and gasoline.
137. xTL refers to liquid fuels that are created from biomass, as in biomass-to-liquids (BTL); from natural gas, as in GTL; and from coal, as in CTL.
138. Permeability is a laboratory measurement of a rock's ability to transmit liquid and gaseous fluids through its pore spaces. High-permeability sandstones have many large and well-connected pore spaces that readily transmit fluids, while low-permeability shales have smaller and fewer interconnected pore spaces that retard fluid flow. Laboratory measurements of rock permeability are stated in terms of darcies or millidarcies.
139. One option for balancing the mix of crudes might be to allow the export of domestically produced light crude in exchange for heavier crudes. Crude exports and swaps, however, are currently permitted only in limited cases and require a license from the Department of Commerce.
140. U.S. Environmental Protection Agency, "EPA Finalizes 2012 Renewable Fuel Standards," EPA-420-F-11-044 (Washington, DC: December 2011), http://www.epa.gov/otaq/fuels/renewablefuels/documents/420f11044.pdf.
141. R. Schnepf and B.D. Yacobucci, *Renewable Fuel Standard (RFS): Overview and Issues* (Washington, DC: Congressional Research Service, January 23, 2012), http://www.fas.org/sgp/crs/misc/R40155.pdf.
142. U.S. Environmental Protection Agency, "Mercury and Air Toxics Standards," http://www.epa.gov/mats.
143. Recent analysis performed by the EPA indicates that upgraded electrostatic precipitators may also enable coal-fired power plants to meet the nonmercury metal emissions control requirement for MATS. This assumption was not included in *AEO2013* but will be revisited in future *AEO*s.
144. U.S. Energy Information Administration, "Dry sorbent injection may serve as a key pollution control technology at power plants," *Today in Energy* (March 16, 2012), http://www.eia.gov/todayinenergy/detail.cfm?id=5430.

# Comparison with other projections

*Energy Information Administration (EIA) and other contributors have 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. None of the EIA or any of the other contributors shall be responsible for any loss sustained due to reliance on the information included in this report.*

Only IHS Global Insight (IHSGI) produces a comprehensive energy projection with a time horizon similar to that of the *Annual Energy Outlook 2013 (AEO2013)*. 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 *AEO2013* Reference case.

## 1. Economic growth

The range of projected economic growth in the outlooks included in the comparison tends to be wider over the first 5 years of the projection than over a longer period, because the group of variables—such as population, productivity, and labor force growth—that influence long-run economic growth is smaller than the group of variables that affect projections of short-run growth. The average annual rate of growth of real gross domestic product (GDP) from 2011 to 2015 (in 2005 dollars) ranges from 2.2 percent to 2.9 percent (Table 8). From 2011 to 2025, the 14-year average annual growth rate ranges from 2.5 percent to 2.8 percent.

From 2011 to 2015, real GDP grows at a 2.5-percent average annual rate in the *AEO2013* Reference case, lower than projected by the Congressional Budget Office (CBO), the Social Security Administration (SSA) (in *The 2011 Annual Report of the Board of Trustees of the Federal Old-Age and Survivors Insurance and Federal Disability Insurance Trust Funds*), Oxford Economic Group (OEG), and the Interindustry Forecasting Project at the University of Maryland (INFORUM) but higher than projected by Blue Chip Consensus (Blue Chip) and the Office of Management and Budget (OMB). The *AEO2013* projection of GDP growth is similar to the average annual rate of 2.5 percent over the same period projected by IHSGI and by the International Energy Agency (IEA), in its November 2012 *World Energy Outlook* Current Policies Scenario.

The average annual GDP growth of 2.6 percent in the *AEO2013* Reference case from 2011 to 2025 is at the mid-range of the outlooks, with OMB, CBO, and the SSA projecting the strongest recovery from the 2007-2009 recession. OMB and CBO project average annual GDP growth from 2011 to 2023 of 2.8 percent and 2.7 percent, respectively. The SSA and OEG project annual average growth of 2.7 percent from 2011 to 2025. IEA projects growth at a rate similar to that in the *AEO2013* Reference case from 2011 to 2025—as do IHSGI and INFORUM—at 2.6 per year over the next 14 years. Blue Chip and ExxonMobil project growth at 2.5 percent, or 0.1 percentage point lower than in the *AEO2013* Reference case.

There are few public or private projections of GDP growth for the United States that extend to 2040. The *AEO2013* Reference case projects 2.5-percent average annual GDP growth from 2011 to 2040, consistent with trends in labor force and productivity growth. IHSGI and INFORUM also project GDP growth averaging 2.5 percent per year from 2011 to 2040. The SSA, ExxonMobil, and IEA project a lower rate of 2.4 percent per year, while the OEG and ICF International (ICF) project a higher rate of 2.6 percent per year from 2011 to 2040.

### Table 8. Comparisons of average annual economic growth projections, 2011-2040

| | Average annual percentage growth rates | | | |
|---|---|---|---|---|
| Projection | 2011-2015 | 2011-2025 | 2025-2040 | 2011-2040 |
| *AEO2013* (Reference case) | 2.5 | 2.6 | 2.4 | 2.5 |
| *AEO2012* (Reference case)[a] | 2.7 | 2.6 | 2.5 | 2.6 |
| IHS Global Insight (August 2012) | 2.5 | 2.6 | 2.5 | 2.5 |
| OMB (January 2013)[a] | 2.2 | 2.8 | -- | -- |
| CBO (February 2013)[a] | 2.6 | 2.7 | -- | -- |
| INFORUM (November 2012) | 2.6 | 2.6 | 2.4 | 2.5 |
| Social Security Administration (August 2012) | 2.9 | 2.7 | 2.2 | 2.4 |
| IEA (2012)[b] | 2.5 | 2.6 | -- | 2.4 |
| Blue Chip Consensus (October 2012)[a] | 2.4 | 2.5 | -- | -- |
| ExxonMobil | -- | 2.5 | 2.2 | 2.4 |
| ICF International | -- | -- | -- | 2.6 |
| Oxford Economics Group (January 2013) | 2.7 | 2.7 | 2.6 | 2.6 |

-- = not reported or not applicable.

[a]OMB, CBO, and Blue Chip forecasts end in 2022, and growth rates cited are for 2011-2022. *AEO2012* projections end in 2035, and growth rates cited are for 2011-2035.

[b]IEA publishes U.S. growth rates for certain intervals: 2010-2015 growth is 2.5 percent, 2010-2020 growth is 2.6 percent, and 2010-2035 growth is 2.4 percent.

## 2. Oil prices

In *AEO2013*, oil prices are represented by spot prices for Brent crude. Prices rise in the Reference case from $111 per barrel in 2011 to about $117 per barrel in 2025 and $163 per barrel in 2040 (Table 9). The price rise starts slowly, then accelerates toward the end of the projection period. In the *Annual Energy Outlook 2012 (AEO2012)* Reference case, where oil prices were represented by the West Texas Intermediate (WTI) spot price, prices rose more sharply in the early years and more slowly at the end of the projection period. *AEO2013* also presents the annual average WTI spot price of light, low-sulfur crude oil delivered in Cushing, Oklahoma, and includes the U.S. annual average refiners' acquisition cost (RAC) of imported crude oil, which is more representative of the average cost of all crude oils used by domestic refiners. In 2011, the WTI and Brent prices differed by $16 per barrel. In the *AEO2013* Reference case, the gap closes to a difference of $2 per barrel in 2025, following resolution of transportation system constraints in the United States. In each of the other outlooks in the comparison, oil spot prices are based on either Brent or WTI prices, with the exception of IEA, which represents the international average of crude oil import prices.

Market volatility and different assumptions about the future of the world economy are reflected in the range of oil price projections for both the near and long term; however, most projections show oil prices rising over the entire projection period. The projections for 2025 range from $78 per barrel (WTI) to $137 per barrel (Brent) in 2025—a span of $59 per barrel—and from $81 per barrel (WTI) to $163 per barrel (Brent) in 2040—a span of $82 per barrel. The wide range underscores the uncertainty inherent in the projections. The range of the projections is encompassed in the range of the *AEO2013* Low and High Oil Price cases, from $68 per barrel (WTI) to $173 per barrel (Brent) in 2025 and from $71 per barrel (WTI) to $213 per barrel (Brent) in 2035.

## 3. Total energy consumption

Four projections by other organizations—INFORUM, IHSGI, ExxonMobil, and IEA—include energy consumption by sector (Table 10). To allow comparison with the IHSGI projection, the *AEO2013* Reference case was adjusted to remove coal-to-liquids (CTL) heat and power, natural gas-to-liquids heat and power, biofuels heat and co-products, and natural gas feedstock use. To allow comparison with the ExxonMobil projection, electricity consumption in each sector was removed from the *AEO2013* Reference case. To allow comparison with the IEA projections, the *AEO2013* Reference case projections for the residential and commercial sectors were combined to produce a buildings sector projection. The IEA projections have a base year of 2010, as opposed to 2011 in the other projections. The INFORUM and IEA projections extend only through 2035.

ExxonMobil includes a cost for carbon dioxide ($CO_2$) emissions in their projection, which helps to explain the lower level of consumption in their outlook. Although the IEA's central case also includes a cost for $CO_2$ emissions, its Current Policies Scenario (which assumes that no new policies are added to those in place in mid-2012) is used for comparison in this analysis, because it corresponds better with the assumptions in the *AEO2013* Reference case. ExxonMobil and IEA show lower total energy consumption across all years in comparison with the *AEO2013* Reference case. Total energy consumption is higher in all years of the IHSGI projection than in the *AEO2013* Reference case but starts from a lower level in 2011.

The INFORUM projection of total energy consumption in 2035 is 2.4 quadrillion British thermal units (Btu) higher than the *AEO2013* Reference case projection, with the transportation sector 2.4 quadrillion Btu higher, the buildings sector 1 quadrillion Btu higher, and the industrial sector 1 quadrillion Btu lower. For the transportation sector, the difference could be related to vehicle efficiency, as the INFORUM projection for motor gasoline consumption (2 quadrillion Btu lower than *AEO2013*) is comparable with the EIA projection in *AEO2012*, which did not include the efficiency standard for vehicle model years 2017 through 2025. Energy consumption growth in the INFORUM projection is weaker than projected in *AEO2013* through 2020 but stronger after 2020.

IHSGI projects significantly higher electricity consumption for all sectors than in the *AEO2013* Reference case, which helps to explain much of the difference in total energy consumption between the two projections. In the IHSGI projection, the electric power sector consumes 10.0 quadrillion Btu more energy in 2040 than in the *AEO2013* Reference case. The greater use of electricity in the IHSGI projection, including 150 trillion Btu used in the transportation sector (more than double the amount in *AEO2013*), also results in higher electricity prices than in the *AEO2013* Reference case.

### Table 9. Comparisons of oil price projections, 2025, 2035, and 2040 (2011 dollars per barrel)

| | | | Projections | | | | | |
|---|---|---|---|---|---|---|---|---|
| | 2011 | | 2025 | | 2035 | | 2040 | |
| | WTI | Brent | WTI | Brent | WTI | Brent | WTI | Brent |
| *AEO2013* (Reference case) | 94.86 | 111.26 | 115.36 | 117.36 | 143.41 | 145.41 | 160.68 | 162.68 |
| *AEO2012* (Reference case) | 94.82 | -- | 135.35 | -- | 148.03 | -- | -- | -- |
| Energy Ventures Analysis, Inc. (EVA) | -- | -- | 78.18 | -- | 82.16 | -- | 87.43 | -- |
| IEA (Current Policies Scenario) | -- | 107.60 | -- | 135.70 | -- | 145.00 | -- | -- |
| INFORUM | -- | 111.26 | -- | 136.77 | -- | 149.55 | -- | -- |
| IHSGI | 94.88 | -- | 93.05 | -- | 86.25 | -- | 81.20 | -- |

Total energy consumption declines in the ExxonMobil projection, primarily as a result of the inclusion of a tax on $CO_2$ emissions, which is not considered in the *AEO2013* Reference case. Energy consumption in the transportation and industrial sectors declines from 2011 levels in the ExxonMobil projection, based on expected policy changes and technology improvements.

Total energy consumption in the IEA projection is higher in 2035 than in 2010 because of increased consumption in the buildings sector, where an increase of 3.7 quadrillion Btu includes 3.1 quadrillion Btu of additional electricity demand. Energy consumption in the transportation and industrial sectors declines from 2020 to 2030 in the IEA projection, by less than 1 quadrillion Btu in each sector. IEA projects little change in energy use for those two sectors from 2030 to 2035, with industrial energy consumption

## Table 10. Comparisons of energy consumption by sector projections, 2025, 2035, and 2040 (quadrillion Btu)

| Sector | *AEO2013* Reference | INFORUM | IHSGI | ExxonMobil | IEA |
|---|---|---|---|---|---|
| | | | 2011 | | |
| Residential | 11.3 | 11.5 | 10.8 | -- | -- |
| Residential excluding electricity | 6.4 | 6.6 | 6.0 | 5.0 | -- |
| Commercial | 8.6 | 8.6 | 8.5 | -- | -- |
| Commercial excluding electricity | 4.1 | 4.1 | 4.0 | 4.0 | -- |
| Buildings sector | 19.9 | 20.1 | 19.3 | -- | 19.3[a] |
| Industrial | 24.0 | 23.6 | -- | -- | 23.7[a] |
| Industrial excluding electricity | 20.7 | 20.2 | -- | 20.0 | -- |
| Losses[b] | 0.7 | -- | -- | -- | -- |
| Natural gas feedstocks | 0.5 | -- | -- | -- | -- |
| Industrial removing losses and feedstocks | 22.9 | -- | 21.7 | -- | -- |
| Transportation | 27.1 | 27.2 | 26.2 | 27.0 | 23.1[a] |
| Electric power | 39.4 | 39.2 | 40.5 | 37.0 | 37.2[a] |
| Less: electricity demand[c] | 12.7 | 12.8 | 12.7 | -- | 15.0[a] |
| Electric power losses | 26.7 | -- | -- | -- | -- |
| **Total primary energy** | **97.7** | **97.3** | **--** | **93.0** | **87.9[a]** |
| **Excluding losses[b] and feedstocks** | **96.6** | **--** | **95.0** | **--** | **--** |
| | | | 2025 | | |
| Residential | 11.0 | 11.5 | 11.8 | -- | -- |
| Residential excluding electricity | 6.0 | 6.3 | 5.8 | 6.0 | -- |
| Commercial | 9.2 | 9.5 | 9.8 | -- | -- |
| Commercial excluding electricity | 4.3 | 4.3 | 4.0 | 3.0 | -- |
| Buildings sector | 20.3 | 21.0 | 21.6 | -- | -- |
| Industrial | 27.5 | 25.4 | -- | -- | -- |
| Industrial excluding electricity | 23.4 | 21.8 | -- | 20.0 | -- |
| Losses[b] | 1.1 | -- | -- | -- | -- |
| Natural gas feedstocks | 0.6 | -- | -- | -- | -- |
| Industrial removing losses and feedstocks | 25.9 | -- | 23.6 | -- | -- |
| Transportation | 26.7 | 27.5 | 25.1 | 26.0 | -- |
| Electric power | 42.1 | 42.6 | 49.0 | 39.0 | -- |
| Less: electricity demand[c] | 14.1 | 14.0 | 16.1 | -- | -- |
| Electric power losses | 27.9 | -- | -- | -- | -- |
| **Total primary energy** | **102.3** | **102.5** | **--** | **94.0** | **--** |
| **Excluding losses[b] and feedstocks** | **100.7** | **--** | **103.2** | **--** | **--** |

-- = not reported.
See notes at end of table.

*(continued on next page)*

declining very slowly and transportation energy consumption increasing slightly. IEA projects total energy consumption that is higher than ExxonMobil's projection in 2035, but considerably lower than in the *AEO2013* Reference case for both 2030 and 2035.

## 4. Electricity

Table 11 compares summary results from the *AEO2013* Reference case with projections from EVA, IHSGI, INFORUM, ICF, and the National Renewable Energy Laboratory (NREL). In 2025, total electricity sales range from a low of 4,095 billion kilowatthours (INFORUM) to a high of 4,712 billion kilowatthours (IHSGI) [*145*]. The *AEO2013* Reference case projects 4,140 billion kilowatthours

### Table 10. Comparisons of energy consumption by sector projections, 2025, 2035, and 2040 (quadrillion Btu) (continued)

| Sector | *AEO2013* Reference | INFORUM | IHSGI | ExxonMobil | IEA |
|---|---|---|---|---|---|
| | | | 2035 | | |
| Residential | 11.4 | 11.9 | 12.5 | -- | -- |
| Residential excluding electricity | 5.7 | 6.1 | 5.7 | 5.0 | -- |
| Commercial | 9.9 | 10.3 | 10.8 | -- | -- |
| Commercial excluding electricity | 4.4 | 4.5 | 4.1 | 3.0 | -- |
| Buildings sector | 21.2 | 22.2 | 23.3 | -- | 23.0 |
| Industrial | 27.8 | 26.8 | -- | -- | 24.2 |
| Industrial excluding electricity | 23.9 | 23.4 | -- | 19.0 | -- |
| Losses[b] | 1.4 | -- | -- | -- | -- |
| Natural gas feedstocks | 0.5 | -- | -- | -- | -- |
| Industrial removing losses and feedstocks | 25.9 | -- | 23.4 | -- | -- |
| Transportation | 26.4 | 28.8 | 22.9 | 25.0 | 22.7 |
| Electric power | 44.1 | 44.1 | 53.6 | 39.0 | 42.7 |
| Less: electricity demand[c] | 15.1 | 15.1 | 18.1 | -- | 18.6 |
| Electric power losses | 29.0 | -- | -- | -- | -- |
| **Total primary energy** | **104.4** | **106.8** | **--** | **91.0** | **93.6** |
| **Excluding losses[b] and feedstocks** | **102.6** | **--** | **105.1** | **--** | **--** |
| | | | 2040 | | |
| Residential | 11.6 | -- | 12.9 | -- | -- |
| Residential excluding electricity | 5.5 | -- | 5.7 | 5.0 | -- |
| Commercial | 10.2 | -- | 11.1 | -- | -- |
| Commercial excluding electricity | 4.5 | -- | 4.1 | 3.0 | -- |
| Buildings sector | 21.8 | -- | 24.0 | -- | -- |
| Industrial | 28.7 | -- | -- | -- | -- |
| Industrial excluding electricity | 24.8 | -- | -- | 18.0 | -- |
| Losses[b] | 1.9 | -- | -- | -- | -- |
| Natural gas feedstocks | 0.4 | -- | -- | -- | -- |
| Industrial removing losses and feedstocks | 26.4 | -- | 23.5 | -- | -- |
| Transportation | 27.1 | -- | 22.0 | 25.0 | -- |
| Electric power | 45.7 | -- | 55.9 | 39.0 | -- |
| Less: electricity demand[c] | 15.7 | -- | 19.1 | -- | -- |
| Electric power losses | 30.0 | -- | -- | -- | -- |
| **Total primary energy** | **107.6** | **--** | **--** | **89.0** | **--** |
| **Excluding losses[b] and feedstocks** | **105.3** | **--** | **106.3** | **--** | **--** |

-- = not reported.
[a]IEA data are for 2010.
[b]Losses in CTL and biofuel production.
[c]Energy consumption in the sectors includes electricity demand purchases from the electric power sector, which are subtracted to avoid double counting in deriving total primary energy consumption.

of total electricity sales in 2025, EVA projects 4,311 billion kilowatthours in 2025, and NREL projects 4,487 billion kilowatthours in 2026. In comparison with the other projections, IHSGI shows higher sales across all sectors in 2025, with the exception of the commercial sector (1,709 billion kilowatthours), where the EVA projection of 1,824 billion kilowatthours is 115 billion kilowatthours higher. The higher total in the commercial sector counterbalances EVA's lower projection of 736 billion kilowatthours for the industrial sector, compared with 1,186 billion kilowatthours in the *AEO2013* Reference case, 1,246 billion kilowatthours in the IHSGI projection, and 1,033 billion kilowatthours in the INFORUM projection.

Total electricity sales in 2035 in the IHSGI projection (5,316 billion kilowatthours) are higher than in the others: 4,406 billion kilowatthours in the INFORUM projection, 4,421 billion kilowatthours in the *AEO2013* Reference case, 4,824 billion kilowatthours (in 2036) in the NREL projection, and 4,923 billion kilowatthours in the EVA projection. EVA projects the highest level of electricity sales in both the residential and commercial sectors in 2035 but a lower level of industrial sales in comparison with the other projections. Electricity sales in the industrial sector in the IHSGI projection are 1,332 billion kilowatthours in 2035, as compared with 1,142 billion kilowatthours in the *AEO2013* Reference case, 978 billion kilowatthours in the INFORUM projection, and only 515 billion kilowatthours in the EVA projection. Total electricity sales in 2040 are again led by the IHSGI projection, with 5,602 billion kilowatthours, followed by 5,238 billion kilowatthours in the EVA projection, 4,608 billion kilowatthours in the *AEO2013* Reference case, and 4,940 billion kilowatthours in the NREL projection.

## Table 11. Comparisons of electricity projections, 2025, 2035, and 2040 (billion kilowatthours, except where noted)

| Projection | 2011 | *AEO2013* Reference case | Other projections: EVA | IHSGI | INFORUM | ICF | NREL |
|---|---|---|---|---|---|---|---|
| | | 2025 | 2025 | 2025 | 2025 | 2025 | 2026 |
| Average end-use price (2011 cents per kilowatthour)[a] | 9.9 | 9.5 | -- | 11.2 | 10.0 | -- | 10.4 |
| Residential | 11.7 | 11.6 | -- | 13.3 | 11.8 | -- | -- |
| Commercial | 10.2 | 9.7 | -- | 11.6 | 10.3 | -- | -- |
| Industrial | 6.8 | 6.5 | -- | 7.6 | 6.8 | -- | -- |
| **Total generation including CHP plus imports** | **4,130** | **4,612** | **4,570** | **5,207** | **4,296** | **4,860** | **4,693** |
| Coal | 1,730 | 1,727 | 1,726 | 1,605 | -- | -- | 1,860 |
| Petroleum | 28 | 18 | -- | 33 | -- | -- | 0 |
| Natural gas[b] | 1,000 | 1,252 | 1,387 | 1,732 | -- | -- | 1,041 |
| Nuclear | 790 | 912 | 890 | 923 | -- | -- | 794 |
| Hydroelectric/other[c] | 544 | 681 | 567 | 852 | -- | -- | 997 |
| Net imports | 37 | 22 | -- | 62 | -- | -- | -- |
| Electricity sales[d] | 3,725 | 4,140 | 4,311 | 4,712 | 4,095 | -- | 4,487 |
| Residential | 1,424 | 1,488 | 1,750 | 1,756 | 1,536 | -- | -- |
| Commercial/other[e] | 1,326 | 1,466 | 1,824 | 1,709 | 1,526 | -- | -- |
| Industrial | 976 | 1,186 | 736 | 1,246 | 1,033 | -- | -- |
| Capacity, including CHP (gigawatts)[f] | 1,049 | 1,098 | 1,141 | 1,237 | -- | 1,135 | 1,146 |
| Coal | 318 | 276 | 255 | 278 | -- | 249 | 273 |
| Oil and natural gas | 463 | 500 | 568 | 555 | -- | 546 | 515 |
| Nuclear | 101 | 114 | 108 | 115 | -- | 106 | 102 |
| Hydroelectric/other[g] | 167 | 208 | 210 | 289 | -- | 234 | 257 |
| Cumulative capacity retirements from 2011 (gigawatts)[h] | -- | 82 | 151 | 83 | -- | 106 | 102 |
| Coal | -- | 49 | 73 | 46 | -- | 73 | 33 |
| Oil and natural gas | -- | 32 | 73 | 36 | -- | 29 | 69 |
| Nuclear | -- | 1 | 3 | 1 | -- | 3 | 0 |
| Hydroelectric/other[g] | -- | 1 | 2 | -- | -- | 0 | 0 |

-- = not reported.
See notes at end of table.

*(continued on next page)*

IHSGI, INFORUM, and the *AEO2013* Reference case provide projections for average electricity prices by sector for 2025 and 2035. NREL provides a U.S. average electricity price projection for 2026 and 2036, but not by sector. IHSGI, NREL, and the *AEO2013* Reference case provide projections for average electricity prices in 2040. Average electricity prices in the *AEO2013* Reference case are 9.5 cents per kilowatthour in 2025, 10.1 cents per kilowatthour in 2035, and 10.8 cents per kilowatthour in 2040. Average electricity prices in the INFORUM projection are 10.0 cents per kilowatthour in 2025 and 10.5 cents per kilowatthour in 2035 [*146*]. IHSGI projects considerably higher average electricity prices than either the *AEO2013* Reference case or INFORUM, at 11.2 cents per kilowatthour in 2025, 11.9 cents per kilowatthour in 2035, and 12.2 cents per kilowatthour in 2040. NREL projects overall average electricity prices of 10.4 cents per kilowatthour in 2026, 11.7 cents per kilowatthour in 2036, and 12.0 cents per kilowatthour in 2040 (the NREL prices were provided in 2009 dollars).

In all the projections, average electricity prices by sector follow patterns similar to changes in the weighted average electricity price across all sectors (including transportation services). The lowest prices by sector in 2025 are in the *AEO2013* Reference case (11.6 cents per kilowatthour for the residential sector, 9.7 cents per kilowatthour for the commercial sector, and 6.5 cents per kilowatthour for the industrial sector). The highest average electricity prices by sector in 2025 are in the IHSGI projection (13.3 cents per kilowatthour for the residential sector, 11.6 cents per kilowatthour for the commercial sector, and 7.6 cents per

## Table 11. Comparisons of electricity projections, 2025, 2035, and 2040 (billion kilowatthours, except where noted) (continued)

| Projection | 2011 | *AEO2013* Reference case | Other projections EVA | IHSGI | INFORUM | ICF | NREL |
|---|---|---|---|---|---|---|---|
| | | 2035 | | | | | 2036 |
| Average end-use price (2011 cents per kilowatthour)[a] | 9.9 | 10.1 | -- | 11.9 | 10.5 | -- | 11.7 |
| Residential | 11.7 | 12.1 | -- | 14.1 | 12.2 | -- | -- |
| Commercial | 10.2 | 10.1 | -- | 12.3 | 10.6 | -- | -- |
| Industrial | 6.8 | 7.1 | -- | 8.1 | 7.1 | -- | -- |
| **Total generation including CHP plus imports** | **4,130** | **4,989** | **5,005** | **5,870** | **4,601** | **5,339** | **4,847** |
| Coal | 1,730 | 1,807 | 1,754 | 1,463 | -- | -- | 1,703 |
| Petroleum | 28 | 18 | -- | 35 | -- | -- | 0 |
| Natural gas[b] | 1,000 | 1,519 | 1,701 | 2,271 | -- | -- | 1,730 |
| Nuclear | 790 | 875 | 839 | 953 | -- | -- | 510 |
| Hydroelectric/other[c] | 544 | 760 | 711 | 1,074 | -- | -- | 904 |
| Net imports | 37 | 10 | -- | 73 | -- | -- | -- |
| Electricity sales[d] | 3,725 | 4,421 | 4,923 | 5,316 | 4,406 | -- | 4,824 |
| Residential | 1,424 | 1,661 | 2,116 | 2,001 | 1,718 | -- | -- |
| Commercial/other[e] | 1,326 | 1,618 | 2,292 | 1,983 | 1,710 | -- | -- |
| Industrial | 976 | 1,142 | 515 | 1,332 | 978 | -- | -- |
| Capacity, including CHP (gigawatts)[f] | 1,049 | 1,206 | 1,263 | 1,420 | -- | 1,285 | 1,253 |
| Coal | 318 | 277 | 255 | 260 | -- | 245 | 238 |
| Oil and natural gas | 463 | 587 | 655 | 676 | -- | 665 | 654 |
| Nuclear | 101 | 109 | 103 | 120 | -- | 80 | 67 |
| Hydroelectric/other[g] | 167 | 233 | 250 | 364 | -- | 295 | 294 |
| Cumulative capacity retirements from 2011 (gigawatts)[h] | -- | 100 | 161 | 115 | -- | 133 | 243 |
| Coal | -- | 49 | 77 | 68 | -- | 82 | 70 |
| Oil and natural gas | -- | 44 | 74 | 38 | -- | 29 | 138 |
| Nuclear | -- | 6 | 9 | 9 | -- | 21 | 35 |
| Hydroelectric/other[g] | -- | 1 | 2 | -- | -- | 0 | 0 |

-- = not reported.
See notes at end of table.

*(continued on next page)*

kilowatthour for the industrial sector). The *AEO2013* Reference case, IHSGI, and NREL reflect similar price patterns for 2035 (or 2036 for NREL) and 2040.

Total U.S. electricity generation plus imports in 2025 range from a low of 4,296 billion kilowatthours in the INFORUM projection to a high of 5,207 billion kilowatthours in the IHSGI projection. Within that range, the *AEO2013* Reference case projects total generation of 4,612 billion kilowatthours. Coal continues to represent the largest share of generation in 2025 in the *AEO2013* Reference case, which reports 1,727 billion kilowatthours from coal versus 1,252 billion kilowatthours from natural gas. By comparison, the natural gas share of total generation in the IHSGI projection in 2025 surpasses generation from coal by 126 billion kilowatthours, with 1,732 billion kilowatthours of generation from natural gas and 1,605 billion kilowatthours from coal. IHSGI projects 1,646 billion kilowatthours of electricity generation from both coal and natural gas in 2023, with the natural

### Table 11. Comparisons of electricity projections, 2025, 2035, and 2040 (billion kilowatthours, except where noted) (continued)

| Projection | 2011 | *AEO2013* Reference case | Other projections | | | | |
|---|---|---|---|---|---|---|---|
| | | | EVA | IHSGI | INFORUM | ICF | NREL |
| | | 2040 | | | | | |
| Average end-use price (2011 cents per kilowatthour)[a] | 9.9 | 10.8 | -- | 12.2 | -- | -- | 12.0 |
| Residential | 11.7 | 12.7 | -- | 14.4 | -- | -- | -- |
| Commercial | 10.2 | 10.8 | -- | 12.5 | -- | -- | -- |
| Industrial | 6.8 | 7.8 | -- | 8.3 | -- | -- | -- |
| **Total generation including CHP plus imports** | **4,130** | **5,230** | **5,479** | **6,189** | **--** | **--** | **4,913** |
| Coal | 1,730 | 1,829 | 1,740 | 1,418 | -- | -- | 1,620 |
| Petroleum | 28 | 18 | -- | 36 | -- | -- | 0 |
| Natural gas[b] | 1,000 | 1,582 | 2,330 | 2,506 | -- | -- | 1,870 |
| Nuclear | 790 | 903 | 756 | 991 | -- | -- | 442 |
| Hydroelectric/other[c] | 544 | 879 | 653 | 1,164 | -- | -- | 981 |
| Net imports | 37 | 18 | -- | 73 | -- | -- | -- |
| Electricity sales[d] | 3,725 | 4,608 | 5,238 | 5,602 | -- | -- | 4,940 |
| Residential | 1,424 | 1,767 | 2,303 | 2,116 | -- | -- | -- |
| Commercial/other[e] | 1,326 | 1,697 | 2,528 | 2,109 | -- | -- | -- |
| Industrial | 976 | 1,145 | 407 | 1,378 | -- | -- | -- |
| Capacity, including CHP (gigawatts)[f] | 1,049 | 1,293 | -- | 1,495 | -- | -- | 1,295 |
| Coal | 318 | 278 | -- | 251 | -- | -- | 224 |
| Oil and natural gas | 463 | 632 | -- | 722 | -- | -- | 691 |
| Nuclear | 101 | 113 | -- | 125 | -- | -- | 58 |
| Hydroelectric/other[g] | 167 | 270 | -- | 396 | -- | -- | 322 |
| Cumulative capacity retirements from 2011 (gigawatts)[h] | -- | 103 | -- | 128 | -- | -- | 276 |
| Coal | -- | 49 | -- | 80 | -- | -- | 86 |
| Oil and natural gas | -- | 46 | -- | 38 | -- | -- | 146 |
| Nuclear | -- | 7 | -- | 9 | -- | -- | 44 |
| Hydroelectric/other[g] | -- | 1 | -- | -- | -- | -- | 0 |

-- = not reported.

[a]Average end-use price includes the transportation sector, NREL end-use prices expressed in 2009 dollars.

[b]Includes supplemental gaseous fuels. For EVA, represents total oil and natural gas.

[c]"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.

[d]Electricity sales for EVA and INFORUM reflect the sum of the individual sector level sales.

[e]"Other" includes sales of electricity to government and other transportation services.

[f]*AEO2013* capacity is net summer capability, including CHP plants and end-use generators.

[g]"Other" includes conventional hydroelectric, geothermal, wood, wood waste, all municipal waste, landfill gas, other biomass, solar, wind, pumped storage, and fuel cells.

[h]IHSGI cumulative capacity retirements are calculated from annual totals. *AEO2013* retirements are for electric power sector only.

gas total exceeding that for coal in 2024 and beyond as a result of the assumed implementation of a carbon tax in the IHSGI projection. Conversely, coal continues to represent the largest share of generation in the *AEO2013* Reference case in 2035—1,807 billion kilowatthours as compared with 1,519 billion kilowatthours from natural gas. The *AEO2013* Reference case is based on current regulations and policies and does not assume a carbon tax. In 2035, the natural gas share of total generation in the IHSGI projection exceeds generation from coal by 808 billion kilowatthours. In the *AEO2013* Reference case, coal continues to represent the largest share of generation in 2040 at 1,829 billion kilowatthours, compared with 1,582 billion kilowatthours from natural gas. In comparison, the natural gas share of total generation in 2040 in the IHSGI projection widens its lead over coal by 1,088 billion kilowatthours. In the EVA projection, coal is outpaced by natural gas as a share of total generation in 2040, with 2,330 billion kilowatthours from natural gas and 1,740 billion kilowatthours from coal [*147*].

Projections for electricity generation from U.S. nuclear power plants in 2025 range from a low of 794 billion kilowatthours (NREL, in 2026) to a high of 923 billion kilowatthours in the IHSGI projection. NREL projects a steady decline in nuclear generation, from 794 billion kilowatthours in 2025 to 510 billion kilowatthours in 2036 and 442 billion kilowatthours in 2040, due to significant plant retirements. For 2035, the *AEO2013* Reference case projects a drop in nuclear generation from the 2025 level, to 875 billion kilowatthours, as a result of capacity retirements. In contrast, nuclear generation increases to 953 billion kilowatthours in 2035 in the IHSGI projection. The *AEO2013* Reference case shows nuclear generation rebounding to 903 billion kilowatthours in 2040, as compared with 991 billion kilowatthours in the IHSGI projection.

Total generating capacity by fuel in 2025 (including combined heat and power [CHP]) is fairly similar across the projections, ranging from a low of 1,098 gigawatts in the *AEO2013* Reference case to a high of 1,237 gigawatts in the IHSGI projection. IHSGI projects slightly more growth in total generating capacity due to what appears to be a much higher demand projection. Natural gas- and oil-fired capacity combined is projected to total 555 gigawatts in 2025 in the IHSGI projection, compared with 500 gigawatts in the *AEO2013* Reference case and a maximum of 568 gigawatts in the EVA projection. In all the projections, the hydroelectric/other category includes generation from both hydroelectric and nonhydroelectric renewable resources. In all the projections, hydroelectric capacity remains essentially unchanged, with almost all growth attributable to nonhydroelectric renewable resources. Hydroelectric/other capacity is the highest in 2025 in the IHSGI outlook at 289 gigawatts, compared with 257 gigawatts in the NREL projection (for 2026), 234 gigawatts in the ICF projection, 210 gigawatts in the EVA projection, and 208 gigawatts in the *AEO2013* Reference case.

Both the IHSGI and NREL projections reflect lower levels of coal-fired generating capacity in 2040, with 251 gigawatts projected by IHSGI and 224 gigawatts by NREL. In comparison, natural gas- and oil-fired capacity (again dominated by natural gas-fired generating capacity) and hydroelectric/other capacity (dominated by nonhydroeletric renewable capacity) are projected to increase from 2025 levels. IHSGI projects 722 gigawatts of natural gas- and oil-fired capacity and 396 gigawatts of hydroelectric/other capacity in 2040. NREL projects 691 gigawatts of natural gas- and oil-fired capacity and 322 gigawatts of hydroelectric/other capacity in 2040. The *AEO2013* Reference case projects 632 gigawatts of natural gas- and oil-fired capacity and 270 gigawatts of hydroelectric/other capacity in 2040.

Cumulative capacity retirements from 2011 through 2025 range from 151 gigawatts in the EVA projection to 82 gigawatts in the *AEO2013* Reference case. The majority of the retirements in the IHSGI, ICF, and *AEO2013* Reference case projections from 2011 to 2025 are attributed to coal-fired capacity. In the EVA and ICF outlooks, 73 gigawatts of coal-fired capacity is retired from 2011 to 2025. Over the same period, 46 gigawatts of coal-fired capacity is retired in the IHSGI outlook and 49 gigawatts in the *AEO2013* Reference case. The NREL projection assumes 33 gigawatts of coal-fired capacity retirements from 2011 to 2026. EVA projects 73 gigawatts of oil- and natural gas-fired capacity retirements between 2011 and 2025, as compared with the ICF, *AEO2013* Reference case, and IHSGI projections, which range between 29 gigawatts and 36 gigawatts over the same period. NREL projects 69 gigawatts of oil- and natural gas-fired retirements through 2026. With the exception of EVA and ICF, all the capacity retirements greater than 1 gigawatt between 2011 and 2025 in the outlooks are attributed to coal, oil, and natural gas capacity. EVA and ICF both project 3 gigawatts of nuclear retirements by 2025, while EVA projects 2 gigawatts of hydroelectric/other capacity retirements for the same period.

Cumulative capacity retirements through 2035 range from a high of 161 gigawatts in the EVA projection to a low of 100 gigawatts in the *AEO2013* Reference case. Coal-fired capacity represents a large portion of the cumulative retirements from 2011 to 2035, with ICF projecting 82 gigawatts, EVA 77 gigawatts, IHSGI 68 gigawatts, and the *AEO2013* Reference case 49 gigawatts. The *AEO2013* Reference case projects no retirements of coal-fired capacity from 2025 to 2035. Over the same period, EVA projects only 4 gigawatts, ICF 9 gigawatts, and IHSGI 22 gigawatts. Cumulative retirements of oil- and natural gas-fired capacity from 2011 to 2035 total 44 gigawatts in the *AEO2013* Reference case and 74 gigawatts in the EVA projection. NREL projects cumulative totals of 70 gigawatts and 138 gigawatts of retirements for coal-fired capacity and for oil- and natural gas-fired capacity, respectively, from 2011 to 2036. EVA and the *AEO2013* Reference case project cumulative nuclear capacity retirements of 9 gigawatts and 6 gigawatts, respectively, from 2011 to 2035, and IHSGI projects 21 gigawatts of cumulative nuclear retirements over the same period. NREL projects 35 gigawatts of cumulative nuclear retirements from 2011 to 2036.

## 5. Natural gas

Projections for natural gas consumption, production, imports, and prices differ significantly among the outlooks compared in Table 12. The variations result, in large part, from differences in underlying assumptions. For example, the *AEO2013* Reference case assumes that current laws and regulations are unchanged through the projection period, whereas some of the other projections

### Table 12. Comparisons of natural gas projections, 2025, 2035, and 2040 (trillion cubic feet, except where noted)

| Projection | 2011 | *AEO2013* Reference case | Other projections: IHSGI | EVA | ICF | ExxonMobil | INFORUM |
|---|---|---|---|---|---|---|---|
| | | | | 2025 | | | |
| Dry gas production[a] | 23.00 | 28.59 | 32.29 | 29.86[b] | 32.39 | -- | 26.26 |
| **Net imports** | **1.95** | **-1.58** | **-1.45** | **1.05** | **-0.63** | **--** | **--** |
| Pipeline | 1.67 | -0.52 | -- | 2.21 | 0.60 | -- | -- |
| LNG | 0.28 | -1.06 | -- | -1.16 | -1.23 | -- | -- |
| **Consumption** | **24.37** | **26.87** | **30.87** | **31.49** | **30.34[c]** | **29.00[c]** | **23.61[d]** |
| Residential | 4.72 | 4.44 | 4.58 | 4.98 | 5.05 | 7.00[e] | 4.84 |
| Commercial | 3.16 | 3.35 | 3.23 | 3.33 | 3.01 | -- | 3.42 |
| Industrial[f] | 6.77 | 7.82 | 7.31 | 8.23 | 8.79 | 9.00 | 7.07 |
| Electricity generators[g] | 7.60 | 8.45 | 12.57 | 11.75 | 10.83 | 13.00 | 8.28 |
| Others[h] | 2.11 | 2.81 | 3.19 | 3.20 | 2.66 | 0.00[i] | -- |
| Henry Hub spot market price (2011 dollars per million Btu) | 3.98 | 4.87 | 4.39 | 6.34 | 5.02 | -- | -- |
| End-use prices (2011 dollars per thousand cubic feet) | | | | | | | |
| Residential | 11.05 | 12.97 | 11.16 | -- | 11.51 | -- | -- |
| Commercial | 9.04 | 10.43 | 9.27 | -- | 9.50 | -- | -- |
| Industrial[j] | 5.00 | 6.29 | 6.42 | -- | 5.88 | -- | -- |
| Electricity generators | 4.87 | 5.70 | 4.89 | -- | 5.85 | -- | -- |
| | | | | 2035 | | | |
| Dry gas production[a] | 23.00 | 31.35 | 36.07 | 31.44[b] | 35.46 | -- | 27.91 |
| **Net imports** | **1.95** | **-2.55** | **-1.18** | **2.62** | **-0.72** | **--** | **--** |
| Pipeline | 1.67 | -1.09 | -- | 3.78 | 0.50 | -- | -- |
| LNG | 0.28 | -1.46 | -- | -1.16 | -1.22 | -- | -- |
| **Consumption** | **24.37** | **28.71** | **34.90** | **34.67** | **33.14[c]** | **30.00[c]** | **24.45[d]** |
| Residential | 4.72 | 4.24 | 4.54 | 4.96 | 5.02 | 7.00[e] | 4.72 |
| Commercial | 3.16 | 3.51 | 3.30 | 3.47 | 2.84 | -- | 3.57 |
| Industrial[f] | 6.77 | 8.38 | 6.85 | 8.61 | 9.01 | 8.00 | 6.94 |
| Electricity generators[g] | 7.60 | 9.44 | 16.15 | 13.98 | 13.36 | 15.00 | 9.23 |
| Others[h] | 2.11 | 3.68 | 4.06 | 3.65 | 2.91 | 1.00[i] | -- |
| Henry Hub spot market price (2011 dollars per million Btu) | 3.98 | 6.32 | 4.98 | 8.00 | 6.21 | -- | -- |
| End-use prices (2011 dollars per thousand cubic feet) | | | | | | | |
| Residential | 11.34 | 15.32 | 11.58 | -- | 12.28 | -- | -- |
| Commercial | 9.28 | 12.26 | 9.78 | -- | 10.38 | -- | -- |
| Industrial[j] | 5.13 | 7.82 | 7.02 | -- | 6.98 | -- | -- |
| Electricity generators | 5.00 | 7.32 | 5.48 | -- | 7.03 | -- | -- |

-- = not reported.
See notes at end of table.

*(continued on next page)*

include assumptions about anticipated policy developments over the next 25 years. In particular, the *AEO2013* Reference case does not incorporate any future changes in policy directed at carbon emissions or other environmental issues, whereas ExxonMobil and some of the other outlooks include explicit assumptions about policies aimed at reducing carbon emissions.

IHSGI and ICF project large increases in natural gas production and consumption over the projection period. IHSGI projects that, as production increases, prices will remain low and U.S. consumers, particularly in the electric power sector, will continue to benefit from an abundance of relatively inexpensive natural gas. In contrast, ICF projects that prices will rise at a more rapid rate than in the IHSGI projection. EVA projects growth in natural gas production, but at lower rates than IHSGI and ICF. Both EVA and ExxonMobil also project strong growth in natural gas consumption in the electric power sector through 2035. EVA differs from the others, however, by projecting strong growth in natural gas consumption despite a rise in natural gas prices to $8.00 per million Btu in 2035. Timing of the growth in consumption is somewhat different between the ExxonMobil projection and the other outlooks. ExxonMobil expects consumption to increase only through 2025, after which it remains relatively flat. The *AEO2013* Reference case projects a smaller increase in natural gas consumption for electric power generation than in the other outlooks, with additional natural gas production allowing for a sharp increase in net exports, particularly as liquefied natural gas (LNG). The INFORUM projection shows a smaller rise in production and consumption of natural gas than in any of the other projections.

### Table 12. Comparisons of natural gas projections, 2025, 2035, and 2040 (trillion cubic feet, except where noted) (continued)

| Projection | 2011 | *AEO2013* Reference case | Other projections: IHSGI | EVA | ICF | ExxonMobil | INFORUM |
|---|---|---|---|---|---|---|---|
| | | 2040 | | | | | |
| Dry gas production[a] | 23.00 | 33.14 | 37.56 | -- | -- | -- | -- |
| **Net imports** | **1.95** | **-3.55** | **-0.95** | **--** | **--** | **--** | **--** |
| Pipeline | 1.67 | -2.09 | -- | -- | -- | -- | -- |
| LNG | 0.28 | -1.46 | -- | -- | -- | -- | -- |
| **Consumption** | **24.37** | **29.54** | **36.61** | **--** | **--** | **30.00[c]** | **--** |
| Residential | 4.72 | 4.14 | 4.52 | -- | -- | 7.00[e] | -- |
| Commercial | 3.16 | 3.60 | 3.29 | -- | -- | -- | -- |
| Industrial[f] | 6.77 | 7.90 | 6.68 | -- | -- | 8.00 | -- |
| Electricity generators[g] | 7.60 | 9.50 | 17.72 | -- | -- | 15.00 | -- |
| Others[h] | 2.11 | 4.40 | 4.40 | -- | -- | 1.00[i] | -- |
| Henry Hub spot market price (2011 dollars per million Btu) | 3.98 | 7.83 | 5.39 | -- | -- | -- | -- |
| End-use prices (2011 dollars per thousand cubic feet) | | | | | | | |
| Residential | 11.05 | 16.74 | 11.81 | -- | -- | -- | -- |
| Commercial | 9.04 | 13.52 | 10.02 | -- | -- | -- | -- |
| Industrial[j] | 5.00 | 9.09 | 7.32 | -- | -- | -- | -- |
| Electricity generators | 4.87 | 8.55 | 5.83 | -- | -- | -- | -- |

-- = not reported.

Note: Totals may not equal sum of components due to independent rounding.

[a]Does not include supplemental fuels.

[b]Lower 48 only.

[c]Does not include lease, plant, and pipeline fuel and fuel consumed in natural gas vehicles.

[d]Does not include lease, plant, and pipeline fuel.

[e]Natural gas consumed in the residential and commercial sectors.

[f]Includes consumption for industrial combined heat and power (CHP) plants and a small number of industrial electricity-only plants, and natural gas-to-liquids heat/power and production; excludes consumption by nonutility generators.

[g]Includes consumption of energy by electricity-only and combined heat and power (CHP) plants whose primary business is to sell electricity, or electricity and heat, to the public. Includes electric utilities, small power producers, and exempt wholesale generators.

[h]Includes lease, plant, and pipeline fuel and fuel consumed in natural gas vehicles.

[i]Fuel consumed in natural gas vehicles only.

[j]The 2011 industrial natural gas price for IHSGI is $6.11.

### Production

All the outlooks shown in Table 12 project increases in natural gas production from the 2011 production level of 23.0 trillion cubic feet. IHSGI projects the largest increase, to 36.1 trillion cubic feet in 2035—13.1 trillion cubic feet or 57 percent more than the 2011 levels—with most of the increase coming in the near term (9.3 trillion cubic feet from 2011 to 2025). An additional 1.5 trillion cubic feet of natural gas production is added from 2035 to 2040. In the ICF projection, natural gas production grows by 12.5 trillion cubic feet over the period from 2011, to 35.5 trillion cubic feet in 2035. More than one-half of the increase (6.5 trillion cubic feet) occurs before 2020. INFORUM projects the smallest increase in natural gas production, at only 4.9 trillion cubic feet from 2011 to the 2035 total of 27.9 trillion cubic feet.

The *AEO2013* Reference case and EVA project more modest growth in natural gas production. In the *AEO2013* Reference case and EVA projections, natural gas production grows to 31.4 trillion cubic feet in 2035, an increase of 8.4 trillion cubic feet from 2011 levels. The *AEO2013* Reference case and EVA projections show slower growth in natural gas production from 2011 to 2025, at 5.6 trillion cubic feet and 6.9 trillion cubic feet, respectively. Although the *AEO2013* Reference case shows the least aggressive near-term growth in natural gas production, it shows the strongest growth from 2025 to 2035 among the projections, with another increase of 1.8 trillion cubic feet from 2035 to 2040.

### Net imports/exports

Differences among the projections for natural gas production generally coincide with differences in total natural gas consumption or net imports/exports. EVA projects positive growth in net imports throughout the projection period, driven by strong growth in natural gas consumption. Although the EVA projection shows significant growth in pipeline imports, it shows no growth in net LNG exports. In contrast, the IHSGI, ICF, and *AEO2013* Reference case projections show net exports of natural gas starting on or before 2020. The *AEO2013* Reference case projects the largest increase in net exports of natural gas, with net pipeline exports increasing alongside steady growth in net LNG exports. In the ICF projection, the United States becomes a net exporter of natural gas by 2020 but remains a net importer of pipeline through 2035. Combined net exports of natural gas grow to 0.7 trillion cubic feet in 2035 in the ICF projection, with all the growth accounted for by LNG exports, which increase by 1.5 trillion cubic feet from 2011 to 2035. IHSGI projects a U.S. shift from net importer to net exporter of natural gas after 2017, with net exports declining after 2024.

### Consumption

All the projections show total natural gas consumption growing throughout the projection periods, and most of them expect the largest increases in the electric power sector. IHSGI projects the greatest growth in natural gas consumption for electric power generation, driven by relatively low natural gas prices, followed by ExxonMobil and EVA, with somewhat higher projections for natural gas prices. The ICF projection shows less growth in natural gas consumption for electric power generation, despite lower natural gas prices, than in the EVA projection. In the *AEO2013* Reference case and INFORUM projections, natural gas consumption for electric power generation is somewhat less than in the other outlooks. Some of that variation may be the result of differences in assumptions about potential fees on carbon emissions. For example, the ExxonMobil outlook assumes a tax on carbon emissions, whereas the *AEO2013* Reference case does not.

Projections for natural gas consumption in the residential and commercial sectors are similar in the outlooks, with expected levels of natural gas use remaining relatively stable over time. The *AEO2013* Reference case projects the lowest level of residential and commercial natural gas consumption, largely as a result of increases in equipment efficiencies, with projected consumption in those sectors falling by 0.1 trillion cubic feet from 2011 to 2040, to a level slightly below those projected by IHSGI and ICF. ExxonMobil projects a significant one-time decrease of 1.0 trillion cubic feet from 2020 to 2025.

The largest difference among the outlooks for natural gas consumption is in the industrial sector, where definitional differences can make accurate comparisons difficult. ExxonMobil and the *AEO2013* Reference case both project increases in natural gas consumption in the industrial sector from 2011 to 2040 that are greater than 1.0 trillion cubic feet, with most of the growth in the *AEO2013* Reference case occurring from 2015 to 2020. ICF projects the largest increase in industrial natural gas consumption, at 2.2 trillion cubic feet from 2011 to 2035, followed by EVA's projection of 1.8 trillion cubic feet over the same period. Although ExxonMobil projects a significant one-time decrease in industrial natural gas consumption—1.0 trillion cubic feet from 2025 to 2030—its projected level of industrial consumption in 2025, at 9.0 trillion cubic feet, is higher than in any of the other projections. Despite ExxonMobil's projected decrease in industrial natural gas consumption from 2025 to 2030, its projection for 2030 (8.0 trillion cubic feet) is second only to EVA's projection of 8.4 trillion cubic feet. IHSGI and INFORUM show modest increases in industrial natural gas consumption from their 2011 levels, to 6.9 trillion cubic feet in 2035 in both outlooks. Projected industrial natural gas consumption declines in the IHSGI projection after 2035, to 6.7 trillion cubic feet in 2040.

### Prices

Only four of the outlooks included in Table 12 provide projections for Henry Hub natural gas spot prices. EVA shows the highest Henry Hub prices in 2035 and IHSGI the lowest. In the IHSGI projection, Henry Hub prices remain low through 2035, when they reach $4.98 per million Btu, compared with $3.98 per million Btu in 2011. Natural gas prices to the electric power sector rise from $4.87 per thousand cubic feet in 2011 to $5.47 per thousand cubic feet in 2035 in the IHSGI projection. The low Henry Hub prices in the IHSGI projection are supported by an abundant supply of relatively inexpensive natural gas, with only a small increase in net exports in comparison with the increase in the *AEO2013* Reference case. EVA, in contrast, shows the Henry Hub price rising to a much higher level of $8.00 per million Btu in 2035, apparently as a result of stronger growth in natural gas consumption, particularly for electric power generation, and a lower level of natural gas exports. Indeed, the EVA outlook shows the U.S. remaining a net importer of natural gas through 2035.

Henry Hub natural gas prices in the ICF and *AEO2013* Reference case projections for 2035—at $6.21 per million Btu and $6.32 per million Btu, respectively—fall within the price range bounded by IHSGI and EVA. In the *AEO2013* Reference case, commercial, electric power, and industrial natural gas prices all rise by between $2 and $3 per thousand cubic feet from 2011 to 2035, while residential prices rise by $3.88 per thousand cubic feet over the same period. The residential sector is also the only sector for which the *AEO2013* Reference case projects a decline in natural gas consumption to below 2011 levels in 2035. ICF projects a much smaller increase in delivered natural gas prices for the commercial, industrial, and electric power sectors, with prices rising to more than $2 per thousand cubic feet above 2011 levels by 2035 only in the electric power sector. With smaller price increases, ICF projects a much larger increase for natural gas consumption in the electric power and industrial sectors from 2011 to 2035 than in the *AEO2013* Reference case.

## 6. Liquid fuels

In the *AEO2013* Reference case, the Brent crude oil spot price (in 2011 dollars) increases to $117 per barrel in 2025, $145 per barrel in 2035, and $163 per barrel in 2040 (Table 13). Prices are higher earlier in the INFORUM and IEA projections but lower in the later years, ranging from $136 per barrel in 2025 to $150 per barrel in 2035. In the *AEO2013* Reference case, the U.S. imported RAC for crude oil (in 2011 dollars) increases to $113 per barrel in 2025, $139 per barrel in 2035, and $155 per barrel in 2040. RAC prices in the INFORUM projection are higher, ranging from $126 per barrel in 2025 to $138 per barrel in 2035. EVA and ExxonMobil did not provide projections for Brent or RAC crude oil prices.

In the *AEO2013* Reference case, domestic crude oil production increases from about 5.7 million barrels per day in 2011 to 6.8 million barrels per day in 2025, then declines to about 6.3 million barrels per day in 2035 and 6.1 million barrels per day in 2040. Overall, projected crude oil production in 2035 is more than 10 percent higher than the 2011 total. The INFORUM projection shows a considerable increase in crude oil production, to 9.5 million barrels per day in 2035. Similarly, the EVA projection shows crude oil production increasing consistently to 8.5 million barrels per day in 2035. The IHSGI projection is closer to the *AEO2013* Reference case, with domestic crude oil production reaching 6.4 million barrels per day in 2035. Similar to the *AEO2013* Reference case, all the outlooks assume continued significant growth in crude oil production from non-OPEC countries, specifically in North America from tight oil formations.

Total net imports of crude oil and other liquids in the *AEO2013* Reference case increase from 8.6 million barrels per day in 2011 to 7.0 million barrels per day in 2025 and remain at that level through the remainder of the projection. The INFORUM projection is similar, at 7.1 million barrels per day in 2025 and 7.4 million barrels per day in 2035. In the IHSGI projection, however, total net imports fall dramatically, to approximately 4.7 million barrels per day in 2035 and around 4.1 million in 2040. IHSGI projects efficiency improvements that would decrease total U.S. demand for liquids and lessen the need for imports.

Biofuel production on a crude oil equivalent basis increases to about 1.1 million barrels per day in both 2025 and in 2035 and to more than 1.3 million barrels per day in 2040 in the *AEO2013* Reference case. IHSGI projects biofuel production of 1.2 million barrels per day in 2025. The IHSGI projection assumes that technology hurdles and economic factors limit the growth of U.S. biofuel production to only a marginal share of total energy supply. IHSGI projects 1.4 million barrels per day of biofuel production in 2035 and a similar level in 2040. The EVA, INFORUM, IEA, and ExxonMobil outlooks do not include biofuels production.

Prices for both diesel fuel and gasoline increase through 2040 in the *AEO2013* Reference case projection, with diesel prices higher than gasoline prices. INFORUM projects increasing gasoline prices and decreasing diesel prices, so that in 2035 the gasoline price is higher than the diesel price. IHSGI projects falling prices for both gasoline and diesel fuel, with 2040 prices for gasoline more than $1.00 per gallon lower and for diesel fuel prices $2.00 per gallon lower than projected in the *AEO2013* Reference case. The EVA, IEA, and ExxonMobil projections do not include delivered fuel prices.

## 7. Coal

The *AEO2013* Reference case projects the highest levels of total coal production and prices in comparison with other coal outlooks available from EVA, ICF, IHSGI, INFORUM, the IEA's *World Energy Outlook*, and ExxonMobil. Total consumption in *AEO2013* is also higher than in the other outlooks, except for INFORUM and ICF, whose consumption projections for 2035 are 2 percent and 5 percent higher, respectively, than projected in the *AEO2013* Reference case (Table 14).

The detailed assumptions that underlie the various projections are not generally available, although there are some important known differences that contribute to the differences among the outlooks. For instance, EVA and ICF assume the implementation of new regulations for cooling water intake and coal combustion residuals; ExxonMobil, which has the lowest projection of coal consumption, assumes a carbon tax; and ICF also includes a carbon cap-and-trade program beginning in 2023. Because those policies are not current law, the *AEO2013* Reference case excludes them, which contributes to the lower coal consumption

**Table 13. Comparisons of liquids projections, 2025, 2035, and 2040 (million barrels per day, except where noted)**

| Projection | 2011 | *AEO2013* Reference case | EVA | INFORUM[a] | IEA[b,c] | ExxonMobil[a] | IHSGI[a] |
|---|---|---|---|---|---|---|---|
| | | | | 2025 | | | |
| Average U.S. imported RAC (2011 dollars per barrel) | 102.65 | 113.48 | -- | 126.18 | -- | -- | 91.38 |
| Brent spot price (2011 dollars per barrel) | 111.26 | 117.36 | 78.18 | 136.77 | 135.70[c] | -- | -- |
| U.S. WTI crude oil price (2011 dollars per barrel) | 94.86 | 115.36 | -- | -- | -- | -- | 93.05 |
| **Domestic production** | **7.88** | **9.96** | **12.08** | **--** | **--** | **--** | **9.52** |
| Crude oil | 5.67 | 6.79 | 8.44 | 8.57 | -- | -- | 6.86 |
| Alaska | 0.57 | 0.35 | 0.36 | -- | -- | -- | -- |
| Natural gas liquids | 2.22 | 3.17 | 3.64 | -- | -- | -- | 2.66 |
| **Total net imports** | **8.58** | **7.01** | **--** | **7.08** | **--** | **--** | **5.98** |
| Crude oil | 8.89 | 7.05 | -- | 7.08 | -- | -- | 7.36 |
| Products | -0.30 | -0.04 | -- | -- | -- | -- | -1.38 |
| Liquids consumption | 18.95 | 19.50 | -- | 18.62 | -- | 19.04 | 17.59 |
| Net petroleum import share of liquids supplied (percent) | 44 | 37 | -- | -- | -- | -- | 33 |
| Biofuel production | 0.97 | 1.08 | -- | -- | -- | -- | 1.18 |
| Transportation product prices (2011 dollars per gallon) | | | | | | | |
| Gasoline | 3.45 | 3.49 | -- | 3.97 | -- | -- | 3.17 |
| Diesel | 3.58 | 3.97 | -- | 4.00 | -- | -- | 3.34 |
| | | | | 2035 | | | |
| Average U.S. imported RAC (2011 dollars per barrel) | 102.65 | 138.70 | -- | 137.97 | -- | -- | 84.51 |
| Brent spot price (2011 dollars per barrel) | 111.26 | 145.41 | 82.16 | 149.55 | 145.00[c] | -- | -- |
| U.S. WTI crude oil price (2011 dollars per barrel) | 94.86 | 143.41 | -- | -- | -- | -- | 86.25 |
| **Domestic production** | **7.88** | **9.17** | **12.42** | **--** | **--** | **--** | **9.31** |
| Crude oil | 5.67 | 6.26 | 8.50 | 9.49 | -- | -- | 6.43 |
| Alaska | 0.57 | 0.35 | 0.00 | -- | -- | -- | -- |
| Natural gas liquids | 2.22 | 2.91 | 3.92 | -- | -- | -- | 2.88 |
| **Total net imports** | **8.58** | **7.00** | **--** | **7.40** | **--** | **--** | **4.67** |
| Crude oil | 8.89 | 7.37 | -- | 7.40 | -- | -- | 7.03 |
| Products | -0.30 | -0.37 | -- | -- | -- | -- | -2.36 |
| Liquids consumption | 18.95 | 18.86 | -- | 19.24 | 15.14 | 18.01 | 16.07 |
| Net petroleum import share of liquids supplied (percent) | 44 | 36 | -- | -- | -- | -- | 28 |
| Biofuel production | 0.97 | 1.13 | -- | -- | -- | -- | 1.39 |
| Transportation product prices (2011 dollars per gallon) | | | | | | | |
| Gasoline | 3.45 | 3.94 | -- | 4.14 | -- | -- | 2.93 |
| Diesel | 3.58 | 4.55 | -- | 4.06 | -- | -- | 3.06 |

-- = not reported.
See notes at end of table.

*(continued on next page)*

projections in many of the other outlooks relative to *AEO2013*. Variation among the assumptions about growth in energy demand and other fuel prices, particularly for natural gas, also contribute to the differences.

Although the *AEO2013* projections for total coal consumption are actually somewhat lower than the ICF and INFORUM projections, the other outlooks offer more pessimistic projections. ExxonMobil is the most pessimistic, with coal consumption 33 percent and 55 percent lower in 2025 and 2030, respectively, than in the *AEO2013* Reference case. Coal consumption in 2025 is 17 percent (174 million tons) less in the EVA outlook than in the *AEO2013* Reference case and 8 percent less in the IHSGI outlook. The INFORUM and ICF outlooks for total coal consumption in 2035 are between 21 million tons (2 percent) and 55 million tons (5 percent) higher, respectively, than in the *AEO2013* Reference case.

The electricity sector is the predominant consumer of coal and the primary source of differences among the projections, due to their differing assumptions about regulations and the economics of coal versus other fuel choices over time. Although EVA shows a greater reduction in coal use for electricity generation in 2025 than does IHSGI, for 2035 the two projections are similar. After 2035, EVA shows a continued small increase in coal use for electricity generation, whereas it continues to fall in the IHSGI projection and in 2040 is 37 million tons less than projected by EVA. The ICF outlook for coal consumption in electricity generation is similar to the *AEO2013* projection through 2025 but then declines gradually through 2035. IEA projects a level of coal use for electricity generation in 2035 that is most similar to the *AEO2013* Reference case.

In all the projections, coal consumption in the end-use sectors is low in comparison with the electric power sector; however, there are several notable differences among the outlooks. Most notably, the ICF outlook shows increasing coal use in the other sectors that offsets declining consumption for electric power. ICF is the only projection that shows an increase in coal use in the industrial and buildings sectors. *AEO2013* shows the next highest level of coal consumption in the industrial and buildings sectors, but it is still less than half of ICF's projection for industrial and buildings consumption in 2035. Both IHSGI and EVA show significant declines in coal use in those sectors over the projection period. In 2040, coal use in the buildings and industrial sectors in the IHSGI and EVA

## Table 13. Comparisons of liquids projections, 2025, 2035, and 2040 (million barrels per day, except where noted) (continued)

| Projection | 2011 | *AEO2013* Reference case | EVA | INFORUM[a] | IEA[b,c] | ExxonMobil[a] | IHSGI[a] |
|---|---|---|---|---|---|---|---|
| | | | | 2040 | | | |
| Average U.S. imported RAC (2011 dollars per barrel) | 102.65 | 154.96 | -- | -- | -- | -- | 79.46 |
| Brent spot price (2011 dollars per barrel) | 111.26 | 162.68 | 87.43 | -- | -- | -- | -- |
| U.S. WTI crude oil price (2011 dollars per barrel) | 94.86 | 160.68 | -- | -- | -- | -- | 81.20 |
| **Domestic production** | **7.88** | **9.05** | **--** | **--** | **--** | **--** | **9.31** |
| Crude oil | 5.67 | 6.13 | -- | -- | -- | -- | 6.43 |
| Alaska | 0.57 | 0.41 | -- | -- | -- | -- | -- |
| Natural gas liquids | 2.22 | 2.92 | -- | -- | -- | -- | 2.88 |
| **Total net imports** | **8.58** | **6.91** | **--** | **--** | **--** | **--** | **4.11** |
| Crude oil | 8.89 | 7.57 | -- | -- | -- | -- | 6.71 |
| Products | -0.30 | -0.67 | -- | -- | -- | -- | -2.60 |
| Liquids consumption | 18.95 | 18.95 | -- | -- | -- | 17.50 | 15.48 |
| Net petroleum import share of liquids supplied (percent) | 44 | 35 | -- | -- | -- | -- | 25 |
| Biofuel production | 0.97 | 1.33 | -- | -- | -- | -- | 1.44 |
| Transportation product prices (2011 dollars per gallon) | | | | | | | |
| Gasoline | 3.45 | 4.32 | -- | -- | -- | -- | 2.78 |
| Diesel | 3.58 | 4.94 | -- | -- | -- | -- | 2.91 |

-- = not reported.

[a]For INFORUM, ExxonMobil, and IHSGI, liquids demand data were converted from quadrillion Btu to barrels at 187.84572 million barrels per quadrillion Btu.

[b]For IEA, liquids demand data were converted from metric tons to barrels at 8.162674 barrels per metric ton.

[c]IEA crude oil prices represent the international average of crude oil import prices.

## Table 14. Comparisons of coal projections, 2025, 2035, and 2040 (million short tons, except where noted)

| Projection | 2011 | *AEO2013* Reference case (million short tons) | *AEO2013* Reference case (quadrillion Btu) | Other projections: EVA[a] | ICF[b] | IHSGI | INFORUM | IEA | ExxonMobil[c] |
|---|---|---|---|---|---|---|---|---|---|
| | | | | (million short tons) | | | | (quadrillion Btu) | |
| **2025** | | | | | | | | | |
| **Production** | **1,096** | **1,113** | **22.54** | **958** | **1,104** | **1,107** | **1,061** | **--** | **--** |
| East of the Mississippi | 456 | 447 | -- | 402 | 445 | -- | -- | -- | -- |
| West of the Mississippi | 639 | 666 | -- | 556 | 659 | -- | -- | -- | -- |
| Consumption | | | | | | | | | |
| Electric power | 929 | 929 | 17.66 | 786 | 939 | 864 | -- | -- | 13 |
| Coke plants | 21 | 22 | 0.58 | 22 | 15 | 19 | -- | -- | -- |
| Coal-to-liquids | -- | 6 | -- | -- | 36 | -- | -- | -- | -- |
| Other industrial/buildings | 49 | 53 | 1.69[d] | 29 | 72 | 44 | 1.96[d] | -- | -- |
| **Total consumption (quadrillion Btu)** | **19.66** | **--** | **19.35** | **--** | **--** | **18.34** | **--** | **--** | **13** |
| **Total consumption (million short tons)** | **999** | **1,010** | **--** | **836** | **1,061** | **927** | **1,015[e]** | **--** | **--** |
| **Net coal exports (million short tons)** | **96** | **124** | **--** | **118** | **43** | **181** | **46** | **--** | **--** |
| Exports | 107 | 129 | -- | 121 | 123 | 183 | 72 | -- | -- |
| Imports | 11 | 5 | -- | 4 | 80[f] | 2 | 26 | -- | -- |
| Minemouth price | | | | | | | | | |
| 2011 dollars per ton | 41.16 | 52.02 | -- | -- | 32.99 | -- | 45.11 | -- | -- |
| 2011 dollars per Btu | 2.04 | 2.60 | -- | -- | 1.66 | -- | 2.65 | -- | -- |
| Average delivered price to electricity generators | | | | | | | | | |
| 2011 dollars per ton | 46.38 | 51.14 | -- | -- | 43.86 | 46.71[g] | 50.83 | -- | -- |
| 2011 dollars per Btu | 2.38 | 2.69 | -- | -- | 2.12 | 2.39 | -- | -- | -- |
| **2035** | | | | | | | | | |
| **Production** | **1,096** | **1,171** | **23.60** | **954** | **1,053** | **1,041** | **1,096** | **--** | **--** |
| East of the Mississippi | 456 | 455 | -- | 397 | 428 | -- | -- | -- | -- |
| West of the Mississippi | 639 | 716 | -- | 558 | 624 | -- | -- | -- | -- |
| Consumption | | | | | | | | | |
| Electric power | 929 | 975 | 18.48 | 791 | 919 | 787 | -- | 18.97[h] | 9 |
| Coke plants | 21 | 18 | 0.48 | 21 | 12 | 18 | -- | -- | -- |
| Coal-to-liquids | -- | 11 | -- | -- | 65 | -- | -- | -- | -- |
| Other industrial/buildings | 49 | 53 | 1.60[d] | 24 | 117 | 36 | 2.12[d] | -- | -- |
| **Total consumption (quadrillion Btu)** | **19.66** | **--** | **20.09** | **--** | **--** | **16.55** | **--** | **21.35[h]** | **9** |
| **Total consumption (million short tons)** | **999** | **1,058** | **--** | **835** | **1,113** | **841** | **1,079[e]** | **--** | **--** |
| **Net coal exports (million short tons)** | **96** | **136** | **--** | **116** | **-61** | **201** | **17** | **--** | **--** |
| Exports | 107 | 158 | -- | 119 | 75 | 203 | 68 | -- | -- |
| Imports | 11 | 22 | -- | 4 | 136[g] | 2 | 51 | -- | -- |
| Minemouth price | | | | | | | | | |
| 2010 dollars per ton | 41.16 | 58.57 | -- | -- | 30.94 | -- | -- | -- | -- |
| 2010 dollars per Btu | 2.04 | 2.94 | -- | -- | 1.58 | -- | 2.88 | -- | -- |
| Average delivered price to electricity generators | | | | | | | | | |
| 2011 dollars per ton | 46.38 | 57.39 | -- | -- | 43.24 | 47.19[g] | 55.20 | -- | -- |
| 2011 dollars per Btu | 2.38 | 3.03 | -- | -- | 2.12 | 2.43 | -- | -- | -- |

-- = not reported.
See notes at end of table.

*(continued on next page)*

projections is equal to only 39 percent and 60 percent, respectively, of the coal use in those sectors in *AEO2013*. In addition, only *AEO2013* and ICF project coal use for liquids production. Some of the gains in the two sectors are offset in the ICF outlook by lower consumption of coal at coke plants, which falls from 21 million tons in 2011 to 12 million tons in 2035. In the other outlooks, coal use at coke plants is similar to the levels in the *AEO2013* Reference case, with modest declines through the end of their projections.

Differences among the projections for U.S. domestic coal production fall within a smaller range than the projections for coal consumption, depending in part on each outlook's projections for net exports. For example, coal production in the EVA and IHSGI projections is buoyed by relatively high export levels after 2011, with total coal production falling by 13 percent and 5 percent, respectively, from 2011 to 2035, compared with a 16-percent decline in total coal consumption in both projections. The ICF and INFORUM outlooks, which project 11-percent and 8-percent increases in total coal consumption through 2035, respectively, show changes in total coal production of 4 percent and no growth, respectively, as a result of significantly lower net export levels.

The projections for coal exports in the *AEO2013* Reference case generally fall between the EVA and IHSGI projections. INFORUM's projection for coal exports is the lowest among the outlooks but similar to ICF's projection for 2035. The composition of EVA's exports also differs from that in *AEO2013*, in that EVA expects most exports to be thermal coal, whereas most exports in the early

## Table 14. Comparisons of coal projections, 2025, 2035, and-2040 (million short tons, except where noted) (continued)

| | | *AEO2013* Reference case | | Other projections | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| Projection | 2011 | (million short tons) | (quadrillion Btu) | EVA[a] (million short tons) | ICF[b] | IHSGI | INFORUM | IEA (quadrillion Btu) | Exxon-Mobil[c] |
| | | 2040 | | | | | | | |
| **Production** | **1,096** | **1,167** | **23.54** | **957** | **--** | **1,015** | **--** | **--** | **--** |
| East of the Mississippi | 456 | 453 | -- | 396 | -- | -- | -- | -- | -- |
| West of the Mississippi | 639 | 714 | -- | 561 | -- | -- | -- | -- | -- |
| Consumption | | | | | | | | | |
| Electric power | 929 | 984 | 18.68 | 797 | -- | 760 | -- | -- | 6 |
| Coke plants | 21 | 18 | 0.46 | 19 | -- | 17 | -- | -- | -- |
| Coal-to-liquids | -- | 14 | -- | -- | -- | -- | -- | -- | -- |
| Other industrial/buildings | 49 | 55 | 1.62[d] | 21 | -- | 33 | -- | -- | -- |
| **Total consumption (quadrillion Btu)** | **19.66** | **--** | **20.35** | **--** | **--** | **15.90** | **--** | **--** | **6** |
| **Total consumption (million short tons)[e]** | **999** | **1,071** | **--** | **838** | **--** | **810** | **--** | **--** | **--** |
| **Net coal exports (million short tons)** | **96** | **123** | **--** | **116** | **--** | **206** | **--** | **--** | **--** |
| Exports | 107 | 159 | -- | 119 | -- | 208 | -- | -- | -- |
| Imports | 11 | 36 | -- | 4 | -- | 2 | -- | -- | -- |
| Minemouth price | | | | | | | | | |
| 2011 dollars per ton | 41.16 | 61.28 | -- | -- | -- | -- | -- | -- | -- |
| 2011 dollars per Btu | 2.04 | 3.08 | -- | -- | -- | -- | -- | -- | -- |
| Average delivered price to electricity generators | | | | | | | | | |
| 2011 dollars per ton | 46.38 | 60.77 | -- | -- | -- | 47.70[g] | -- | -- | -- |
| 2011 dollars per Btu | 2.38 | 3.20 | -- | -- | -- | 2.46 | -- | -- | -- |

-- = not reported.

[a]Regulations known to be accounted for in the EVA projections include MATS, CAIR, regulations for cooling-water intake structures under Section 316(b) of the Clean Water Act, and regulations for coal combustion residuals under authority of the Resource Conservation and Recovery Act.

[b]Regulations known to be accounted for in the ICF projections include MATS for mercury, HCl and filterables PM requirements starting in 2016, Phase I and II for CAIR followed by a more stringent CAIR replacement in 2018 to address 2012 NAAQS for PM2.5, final state-level mercury restrictions prior to MATS start date and in instances where the state requirement is more stringent than MATS, entrainments requirements for cooling water intake structures beginning in 2025, and coal combustion residual requirements under subtitle D starting in 2018, and a federal carbon cap and trade program starting in 2023.

[c]ExxonMobil projections include a carbon tax.

[d]Coal consumption in quadrillion Btu. INFORUM's value appears to include coal consumption at coke plants. To facilitate comparison, the *AEO2013* value also includes coal consumption at coke plants.

[e]Calculated as imports = (consumption - production + exports).

[f]Calculated as consumption = (production - exports + imports).

[g]Imputed, using heat conversion factor implied by U.S. steam coal consumption data for the electricity sector.

[h]For IEA, data were converted from million tons of oil equivalent using a conversion factor of 39.683 million Btu per ton of oil equivalent.

years of the *AEO2013* Reference case are coking coal. In 2025, coking coal accounts for 57 percent of total coal exports in the *AEO2013* Reference case, compared with 34 percent in the EVA projection. In 2040, however, the coking coal share of exports in the *AEO2013* projection declines to 44 percent, compared with 32 percent in the EVA projection. In comparison, coking coal accounts for 74 percent of total coal exports in 2035 in the ICF projection.

In the EVA and IHSGI projections, coal imports remain low and relatively flat. *AEO2013* also shows low levels of imports initially, but they grow to 36 million tons in 2040 from 5 million tons in 2025. For 2035, the ICF outlook implies 136 million tons of coal imports (calculated by subtracting production from the sum of consumption and exports), which is higher than all the others shown in the comparison table. Coal imports remain above 20 million tons in the INFORUM projections, and as in the ICF and *AEO2013* projections, they increase over time, doubling in 2035 from the 2025 level.

Only *AEO2013*, ICF, and INFORUM provide projections of minemouth coal prices. In the ICF projections, minemouth prices in 2025 are 20 percent below those in 2011 (on a dollar-per-ton basis), and they decline only slightly through 2035. INFORUM projects coal minemouth prices that are very similar to the *AEO2013* prices (on a dollar-per-million Btu basis).

The ICF outlook shows the lowest price for coal delivered to the electricity sector in both 2025 and 2035, with the real coal price lower than in 2011. INFORUM's prices for coal delivered to electricity generators (on a dollar-per-ton basis) are similar. IHSGI's delivered coal prices to electricity generators are significantly lower than those in the *AEO2013* Reference case and remain close to the 2011 price over the entire projection period. As a result, the IHSGI delivered coal price to electricity generators is 9 percent lower in 2025 and 22 percent lower in 2040, on a dollar-per-ton basis, than projected in the *AEO2013* Reference case.

# Endnotes for Comparison with other projections

**Links current as of March 2013**

145. EIA summed the sector-level sales from the INFORUM and EVA projections to develop a total electricity sales value for comparison purposes.
146. EIA estimated a weighted-average electricity price for INFORUM based on the sector-level prices and sales.
147. For purposes of comparison, generation from natural gas, turbine, and oil/gas steam capacity from EVA was combined, resulting in a total of 2,330 billion kilowatthours of generation from natural gas for 2040, as shown in Table 25.

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# List of acronyms

| | |
|---|---|
| AB 32 | California Assembly Bill 32 |
| ACP | Alternative compliance payment |
| *AEO* | *Annual Energy Outlook* |
| *AEO2012* | *Annual Energy Outlook 2012* |
| *AEO2013* | *Annual Energy Outlook 2013* |
| API | American Petroleum Institute |
| ARRA2009 | American Recovery and Reinvestment Act of 2009 |
| ATRA | American Taxpayer Relief Act of 2012 |
| Blue Chip | Blue Chip Consensus |
| BTL | Biomass-to-liquids |
| Btu | British thermal units |
| CAFE | Corporate average fuel economy |
| CAIR | Clean Air Interstate Rule |
| CARB | California Air Resources Board |
| CBO | Congressional Budget Office |
| CBTL | Coal- and biomass-to-liquids |
| CCS | Carbon capture and storage |
| CHP | Combined heat and power |
| CMM | Coal Market Module |
| CNG | Compressed natural gas |
| CO | Carbon monoxide |
| $CO_2$ | Carbon dioxide |
| $CO_2e$ | Carbon dioxide equivalent |
| COL | Combined license |
| $CO_2$-EOR | Carbon dioxide-enhanced oil recovery |
| CSAPR | Cross-State Air Pollution Rule |
| CTL | Coal-to-liquids |
| DG | Distributed generation |
| DOE | U.S. Department of Energy |
| DSI | Dry sorbent injection |
| E10 | Motor gasoline blend containing up to 10 percent ethanol |
| E15 | Motor gasoline blend containing up to 15 percent ethanol |
| E85 | Motor fuel containing up to 85 percent ethanol |
| EIA | U.S. Energy Information Administration |
| EIEA2008 | Energy Improvement and Extension Act of 2008 |
| EISA2007 | Energy Independence and Security Act of 2007 |
| EMM | Electricity Market Module |
| EOR | Enhanced oil recovery |
| EPA | U.S. Environmental Protection Agency |
| EPACT2005 | Energy Policy Act of 2005 |
| EUR | Estimated ultimate recovery |
| EVA | Energy Ventures Analysis |
| FCC | Fluid catalytic cracking |
| FFV | Flex-fuel vehicle |
| FGD | Flue gas desulfurization |
| GDP | Gross domestic product |
| GHG | Greenhouse gas |
| GTL | Gas-to-liquids |
| GVWR | Gross vehicle weight rating |
| HAP | Hazardous air pollutant |
| HDV | Heavy-duty vehicle |
| Hg | Mercury |
| ICF | ICF International |
| IDM | Industrial Demand Module |
| IEA | International Energy Agency |
| IEM | International Energy Module |
| IHSGI | IHS Global Insight, Inc. |
| INFORUM | Interindustry Forecasting Project at the University of Maryland |
| ITC | Investment tax credit |
| LCFS | Low Carbon Fuel Standard |
| LDV | Light-duty vehicle |
| LED | Light-emitting diode |
| LFG | Landfill gas |
| LFMM | Liquid Fuels Market Module |
| LNG | Liquefied natural gas |
| LPG | Liquefied petroleum gases |
| MACT | Maximum achievable control technology |
| MATS | Mercury and Air Toxics Standards |
| MAM | Macroeconomic Activity Module |
| $MMTCO_2e$ | Million metric tons carbon dioxide equivalent |
| mpg | Miles per gallon |
| MY | Model year |
| MSW | Municipal solid waste |
| NAICS | North American Industry Classification System |
| NEMS | National Energy Modeling System |
| NESHAP | National Emissions Standards for Hazardous Air Pollutants |
| NGCC | Natural gas combined-cycle |
| NGL | Natural gas liquids |
| NGPL | Natural gas plant liquids |
| NGTDM | Natural Gas Transmission and Distribution Module |
| NHTSA | National Highway Traffic Safety Administration |
| $NO_X$ | Nitrogen oxides |
| NRC | U.S. Nuclear Regulatory Commission |
| NREL | National Renewable Energy Laboratory |
| O&M | Operations and maintenance |
| OECD | Organization for Economic Cooperation and Development |
| OEG | Oxford Economics Group |
| OMB | Office of Management and Budget |
| OPEC | Organization of the Petroleum Exporting Countries |
| PADDs | Petroleum Administration for Defense Districts |
| PCs | Personal computers |
| PM | Particulate matter |
| PTC | Production tax credit |
| PV | Solar photovoltaic |
| RAC | U.S. refiner acquisition cost |
| RFM | Renewable Fuels Module |
| RFS | Renewable fuel standard |
| RPS | Renewable portfolio standard |
| SCR | Selective catalytic reduction |
| SMR | Small modular reactor |
| SNCR | Selective noncatalytic reduction |
| SONGS | San Onofre Nuclear Generating Station |
| $SO_2$ | Sulfur dioxide |
| SSA | Social Security Administration |
| *STEO* | *Short-Term Energy Outlook* |
| TRR | Technically recoverable resource |
| TVA | Tennessee Valley Authority |
| VMT | Vehicle miles traveled |
| WTI | West Texas Intermediate |

# Notes and sources

## Table notes and sources

### Legislation and regulations

**Table 1. NHTSA projected average fleet-wide CAFE compliance levels for passenger cars and light-duty trucks, model years 2017-2025, based on the model year 2010 baseline fleet:** U.S. Environmental Protection Agency and National Highway Traffic Safety Administration, "2017 and Later Model Year Light-Duty Vehicle Greenhouse Gas Emissions and Corporate Average Fuel Economy Standards; Final Rule," *Federal Register,* Vol. 77, No. 199 (Washington, DC, October 15, 2012), https://federalregister.gov/articles/2012/10/15/2012-21972/2017-and-later-model-year-light-duty-vehicle-greenhouse-gas-emissions-and-corporate-average-fuel.

**Table 2. *AEO2013* projected average fleet-wide CAFE compliance levels for passenger cars and light-duty trucks, model years 2017-2025:** AEO2013 National Energy Modeling System, run REF2013.D102312A.

**Table 3. Renewable portfolio standards in the 30 States and District of Columbia with current mandates:** U.S. Energy Information Administration, Office of Energy Analysis. Based on a review of enabling legislation and regulatory actions from the various States of policies identified by the Database of States Incentives for Renewable Energy as of December 15, 2012, http://www.dsireusa.org.

### Issues in focus

**Table 4. Key analyses from "Issues in focus" in recent *AEO*s:** U.S. Energy Information Administration, *Annual Energy Outlook 2012,* DOE/EIA-0383(2012) (Washington, DC, June 2012); U.S. Energy Information Administration, *Annual Energy Outlook 2011,* DOE/EIA-0383(2011) (Washington, DC, April 2011); and U.S. Energy Information Administration, *Annual Energy Outlook 2010,* DOE/EIA-0383(2010) (Washington, DC, April 2010).

**Table 5. Differences in crude oil and natural gas assumptions across three cases:** AEO2013 National Energy Modeling System, runs REF2013.D102312A, LOWRESOURCE.D011813A, and HIGHRESOURCE.D021413A.

**Table 6. Differences in transportation demand assumptions across three cases:** AEO2013 National Energy Modeling System, runs REF2013.D102312A, LOWIMPORT.D021113B, and HIGHIMPORT.D012813A.

**Table 7. Proposed U.S. ethylene production capacity, 2013-2020:** Stephen Zinger et. al., "A Renaissance for U.S. Gas-Intensive Industries Part 2," Wood Mackenzie (November 2012).

### Comparison with other projections

**Table 8. Projections of average annual economic growth, 2011-2040: *AEO2013* (Reference case):** AEO2013 National Energy Modeling System, run REF2013.D102312A. ***AEO2012* (Reference case):** AEO2012 National Energy Modeling System, run AEO2012.REF2012.D020112C. **IHSGI:** IHS Global Insight, *30-year U.S. and Regional Economic Forecast* (Lexington, MA, November 2012), http://www.ihs.com/products/global-insight/index.aspx (subscription site). **OMB:** Office of Management and Budget, *Fiscal Year 2013 Budget of the U.S. Government* (Washington, DC, January 2013), http://www.whitehouse.gov/sites/default/files/omb/budget/fy2013/assets/budget.pdf. **CBO:** Congressional Budget Office, The Budget and Economic Outlook: Fiscal Years 2012 to 2022 (Washington, DC, February 2013), http://www.cbo.gov/publication/42905. **INFORUM:** "INFORUM AEO2012 Reference Case, Lift (Long-term Interindustry Forecasting Tool) Model" (College Park, MD, December 2012), http://inforumweb.umd.edu/services/models/lift.html. **SSA:** Social Security Administration, *The 2012 Annual Report of the Board of Trustees of the Federal Old-Age And Survivors Insurance and Federal Disability Insurance Trust Funds* (U.S. Government Printing Office, Washington, DC, April 23 2012), http://www.ssa.gov/oact/tr/2012/2012_Long-Range_Economic_Assumptions.pdf. **IEA (2012):** International Energy Agency, *World Energy Outlook 2012* (Paris, France, November 2012), http://www.worldenergyoutlook.org. **Blue Chip Consensus:** *Blue Chip Economic Indicators* (Aspen Publishers, October 2012), http://www.aspenpublishers.com/Topics/Banking-Law-Finance-Economic-Forecast/. **ExxonMobil:** ExxonMobil Corporation, *ExxonMobil 2013: The Outlook for Energy: A View to 2040* (Irving, TX, 2013), http://www.exxonmobil.com/Corporate/energy_outlook.aspx. **ICF:** "ICF Integrated Energy Outlook Q4 2012," ICF Integrated Planning Model (IPM) and Gas Market Model (GMM) (Fairfax, VA, 4th Quarter, 2012). **Oxford Economics Group:** Oxford Economics, Ltd., 2013 Long Term Forecast (Oxford, United Kingdom, January 2013), http://www.OxfordEconomics.com (subscription site).

**Table 9. Projections of oil prices, 2025, 2035, and 2040: *AEO2013* (Reference case):** AEO2013 National Energy Modeling System, run REF2013.D102312A. ***AEO2012* (Reference case):** AEO2012 National Energy Modeling System, run AEO2012.REF2012.D020112C. **EVA:** Energy Ventures Analysis, Inc., e-mail from Anthony Petruzzo (December 21, 2012). **IEA (Current Policies Scenario):** International Energy Agency, *World Energy Outlook 2012* (Paris, France, November 2012), http://www.worldenergyoutlook.org. **INFORUM:** "INFORUM AEO2012 Reference Case, Lift (Long-term Interindustry Forecasting Tool) Model" (College Park, MD, December 2012), http://inforumweb.umd.edu/services/models/lift.html. **IHSGI:** IHS Global Insight, *30-year U.S. and Regional Economic Forecast* (Lexington, MA, November 2012), http://www.ihs.com/products/global-insight/index.aspx (subscription site).

**Table 10. Projections of energy consumption by sector, 2025, 2035, and 2040: *AEO2013* (Reference case):** AEO2013 National Energy Modeling System, run REF2013.D102312A. **INFORUM:** "INFORUM AEO2012 Reference Case, Lift (Long-term Interindustry Forecasting Tool) Model" (College Park, MD, December 2012), http://inforumweb.umd.edu/services/models/lift.html. **IHSGI:** IHS Global Insight, *30-year U.S. and Regional Economic Forecast* (Lexington, MA, November 2012), http://www.ihs.com/products/global-insight/index.aspx (subscription site). **ExxonMobil:** ExxonMobil Corporation, *ExxonMobil 2013: The Outlook for Energy: A View to 2040* (Irving, TX, 2013), http://www.exxonmobil.com/Corporate/energy_outlook.aspx. **IEA:** International Energy Agency, *World Energy Outlook 2012* (Paris, France, November 2012), http://www.worldenergyoutlook.org.

**Table 11. Comparison of electricity projections, 2025, 2035, and 2040: *AEO2013* (Reference case):** AEO2013 National Energy Modeling System, run REF2013.D102312A. **EVA:** Energy Ventures Analysis, Inc., e-mail from Anthony Petruzzo (December 21, 2012). **IHSGI:** IHS Global Insight, *30-year U.S. and Regional Economic Forecast* (Lexington, MA, November 2012), http://www.ihs.com/products/global-insight/index.aspx (subscription site). **INFORUM:** "INFORUM AEO2012 Reference Case, Lift (Long-term Interindustry Forecasting Tool) Model" (College Park, MD, December 2012), http://inforumweb.umd.edu/services/models/lift.html. **ICF:** "ICF Integrated Energy Outlook Q4 2012," ICF Integrated Planning Model (IPM) and Gas Market Model (GMM) (Fairfax, VA, 4th Quarter 2012. **NREL:** National Renewable Energy Laboratory, e-mail from Trieu Mai (January 14, 2013).

**Table 12. Comparison of natural gas projections, 2025, 2035, and 2040: *AEO2013* (Reference case):** AEO2013 National Energy Modeling System, run REF2013.D102312A. **IHSGI:** IHS Global Insight, *30-year U.S. and Regional Economic Forecast* (Lexington, MA, November 2012), http://www.ihs.com/products/global-insight/index.aspx (subscription site). **EVA:** Energy Ventures Analysis, Inc., e-mail from Anthony Petruzzo (December 21, 2012). **ICF:** "ICF Integrated Energy Outlook Q4 2012," ICF Integrated Planning Model (IPM) and Gas Market Model (GMM)" (Fairfax, VA, 4th Quarter 2012). **ExxonMobil:** ExxonMobil Corporation, *ExxonMobil 2013: The Outlook for Energy: A View to 2040* (Irving, TX, 2013), http://www.exxonmobil.com/Corporate/energy_outlook.aspx. **INFORUM:** "INFORUM AEO2012 Reference Case, Lift (Long-term Interindustry Forecasting Tool) Model" (College Park, MD, December 2012), http://inforumweb.umd.edu/services/models/lift.html.

**Table 13. Comparison of liquids projections, 2025, 2035, and 2040: *AEO2013* (Reference case):** AEO2013 National Energy Modeling System, run REF2013.D102312A. **EVA:** Energy Ventures Analysis, Inc., e-mail from Anthony Petruzzo (December 21, 2012). **IHSGI:** IHS Global Insight, *30-year U.S. and Regional Economic Forecast* (Lexington, MA, November 2012), http://www.ihs.com/products/global-insight/index.aspx (subscription site). **INFORUM:** "INFORUM AEO2012 Reference Case, Lift (Long-term Interindustry Forecasting Tool) Model" (College Park, MD, December 2012), http://inforumweb.umd.edu/services/models/lift.html. **IEA:** International Energy Agency, *World Energy Outlook 2012* (Paris, France, November 2012), http://www.worldenergyoutlook.org. **ExxonMobil:** ExxonMobil Corporation, *ExxonMobil 2013: The Outlook for Energy: A View to 2040* (Irving, TX, 2013), http://www.exxonmobil.com/Corporate/energy_outlook.aspx.

**Table 14. Comparison of coal projections, 2025, 2035, and 2040: *AEO2013* (Reference case):** AEO2013 National Energy Modeling System, run REF2013.D102312A. **EVA:** Energy Ventures Analysis, Inc., e-mail from Anthony Petruzzo (December 21, 2012). **ICF:** "ICF Integrated Energy Outlook Q4 2012," ICF Integrated Planning Model (IPM) and Gas Market Model (GMM) (Fairfax, VA, 4th Quarter 2012). **IHSGI:** IHS Global Insight, *30-year U.S. and Regional Economic Forecast* (Lexington, MA, November 2012), http://www.ihs.com/products/global-insight/index.aspx (subscription site). **INFORUM:** "INFORUM AEO2012 Reference Case, Lift (Long-term Interindustry Forecasting Tool) Model" (College Park, MD, December 2012), http://inforumweb.umd.edu/services/models/lift.html. **IEA:** International Energy Agency, *World Energy Outlook 2012* (Paris, France, November 2012), http://www.worldenergyoutlook.org. **ExxonMobil:** ExxonMobil Corporation, *ExxonMobil 2013: The Outlook for Energy: A View to 2040* (Irving, TX, 2013), http://www.exxonmobil.com/Corporate/energy_outlook.aspx.

## Figure notes and sources

### Executive summary

**Figure 1. Net import share of U.S. liquids supply in two cases, 1970-2040: History:** U.S. Energy Information Administration, *Annual Energy Review 2011,* DOE/EIA-0384(2011) (Washington, DC, September 2012). Projections: AEO2013 National Energy Modeling System, runs REF2013.D102312A and LOWIMPORT.D021113A.

**Figure 2. Total U.S. natural gas production, consumption, and net imports, 1990-2040: History:** U.S. Energy Information Administration, *Natural Gas Annual 2011,* DOE/EIA-0131(2011) (Washington, DC, January 2013). Projections: AEO2013 National Energy Modeling System, run REF2013.D102312A.

**Figure 3. Power sector electricity generation from coal and natural gas in two cases, 2008-2040: History:** U.S. Energy Information Administration, *Annual Energy Review 2011,* DOE/EIA-0384(2011) (Washington, DC, September 2012). **Projections:** AEO2013 National Energy Modeling System, run REF2013.D102312A and HIGHRESOURCE.D021413A.

**Figure 4. Coal and natural gas use in the electric power sector in three cases, 2011, 2025, and 2040: 2011:** U.S. Energy Information Administration, *Annual Energy Review 2011,* DOE/EIA-0384(2011) (Washington, DC, September 2012). **Projections:** AEO2013 National Energy Modeling System, runs REF2013.D102312A, HIGHRESOURCE.D021413A, and CO2FEE15.D021413A.

**Figure 5. Energy-related carbon dioxide emissions in four cases, 2000-2040: History:** U.S. Energy Information Administration, *Annual Energy Review 2011,* DOE/EIA-0384(2011) (Washington, DC, September 2012). **Projections:** AEO2013 National Energy Modeling System, runs REF2013.D102312A, HIGHRESOURCE.D021413A, CO2FEE10.D021413A, CO2FEE15.D021413A, CO2FEE25.D021413A, CO2FEE10HR.D021413A, CO2FEE15HR.D021413A, and CO2FEE25HR.D021413A.

**Figure 6. Transportation energy consumption by fuel, 1990-2040: History:** U.S. Energy Information Administration, *Annual Energy Review 2011,* DOE/EIA-0384(2011) (Washington, DC, September 2012). **Projections:** AEO2013 National Energy Modeling System, run REF2013.D102312A.

**Figure 7. U.S. dry natural gas consumption by sector, 2005-2040: History:** U.S. Energy Information Administration, *Annual Energy Review 2011,* DOE/EIA-0384(2011) (Washington, DC, September 2012). **Projections:** AEO2013 National Energy Modeling System, run REF2013.D102312A.

**Figure 8. Renewable energy share of U.S. electricity generation in five cases, 2000-2040: History:** U.S. Energy Information Administration, *Annual Energy Review 2011,* DOE/EIA-0384(2011) (Washington, DC, September 2012). **Projections:** AEO2013 National Energy Modeling System, runs REF2013.D102312A, CO2FEE10.D021413A, CO2FEE15.D021413A, and CO2FEE25.D021413A.

## Legislation and regulations

**Figure 9. Projected average passenger car CAFE compliance targets by vehicle footprint, model years 2017-2025:** U.S. Environmental Protection Agency and National Highway Traffic Safety Administration, "2017 and Later Model Year Light-Duty Vehicle Greenhouse Gas Emissions and Corporate Average Fuel Economy Standards; Final Rule," Federal Register, Vol. 77, No. 199 (Washington, DC, October 15, 2012), https://www.federalregister.gov/articles/2012/10/15/2012-21972/2017-and-later-model-year-light-duty-vehicle-greenhouse-gas-emissions-and-corporate-average-fuel.

**Figure 10. Projected average light-duty truck CAFE compliance targets by vehicle footprint, model years 2017-2025:** U.S. Environmental Protection Agency and National Highway Traffic Safety Administration, "2017 and Later Model Year Light-Duty Vehicle Greenhouse Gas Emissions and Corporate Average Fuel Economy Standards; Final Rule," Federal Register, Vol. 77, No. 199 (Washington, DC, October 15, 2012), https://www.federalregister.gov/articles/2012/10/15/2012-21972/2017-and-later-model-year-light-duty-vehicle-greenhouse-gas-emissions-and-corporate-average-fuel.

**Figure 11. States covered by CAIR limits on emissions of sulfur dioxide and nitrogen oxides:** U.S. Environmental Protection Agency, States Covered by CAIR, http://www.epa.gov/cair/where.html.

**Figure 12. Total renewable generation required for combined state renewable portfolio standards and projected total achieved, 2012-2040:** AEO2013 National Energy Modeling System, run REF2013.D102312A.

## Issues in focus

**Figure 13. Total energy consumption in three cases, 2005-2040: History:** U.S. Energy Information Administration, *Annual Energy Review 2011,* DOE/EIA-0384(2011) (Washington, DC, September 2012). **Projections:** AEO2013 National Energy Modeling System, runs REF2013.D102312A, NOSUNSET.D120712A, and EXTENDED.D010313A.

**Figure 14. Consumption of petroleum and other liquids for transportation in three cases, 2005-2040:** History: U.S. Energy Information Administration, *Annual Energy Review 2011,* DOE/EIA-0384(2011) (Washington, DC, September 2012). **Projections:** AEO2013 National Energy Modeling System, runs REF2013.D102312A, NOSUNSET.D120712A, and EXTENDED.D010313A.

**Figure 15. Renewable electricity generation in three cases, 2005-2040: History:** U.S. Energy Information Administration, *Annual Energy Review 2011,* DOE/EIA-0384(2011) (Washington, DC, September 2012). **Projections:** AEO2013 National Energy Modeling System, runs REF2013.D102312A, NOSUNSET.D120712A, and EXTENDED.D010313A.

**Figure 16. Renewable electricity generation in two cases, 2012-2040: History:** U.S. Energy Information Administration, *Annual Energy Review 2010,* DOE/EIA-0384(2010) (Washington, DC, October 2011). **Projections:** AEO2012 National Energy Modeling System, runs REF2012.D020112C and AEO2013HR8.D021213A.

**Figure 17. Electricity generation from natural gas in three cases, 2005-2040: History:** U.S. Energy Information Administration, *Annual Energy Review 2011,* DOE/EIA-0384(2011) (Washington, DC, September 2012). **Projections:** AEO2013 National Energy Modeling System, runs REF2013.D102312A, NOSUNSET.D120712A, and EXTENDED.D010313A.

**Figure 18. Energy-related carbon dioxide emissions in three cases, 2005-2040: History:** U.S. Energy Information Administration, *Annual Energy Review 2011,* DOE/EIA-0384(2011) (Washington, DC, September 2012). **Projections:** AEO2013 National Energy Modeling System, runs REF2013.D102312A, NOSUNSET.D120712A, and EXTENDED.D010313A.

**Figure 19. Average delivered prices for natural gas in three cases, 2005-2040: History:** U.S. Energy Information Administration, *Annual Energy Review 2011,* DOE/EIA-0384(2011) (Washington, DC, September 2012). **Projections:** AEO2013 National Energy Modeling System, runs REF2013.D102312A, NOSUNSET.D120712A, and EXTENDED.D010313A.

**Figure 20. Average electricity prices in three cases, 2005-2040: History:** U.S. Energy Information Administration, *Annual Energy Review 2011,* DOE/EIA-0384(2011) (Washington, DC, September 2012). **Projections:** AEO2013 National Energy Modeling System, runs REF2013.D102312A, NOSUNSET.D120712A, and EXTENDED.D010313A.

**Figure 21. Annual average spot price for Brent crude oil in three cases, 1990-2040: History:** U.S. Energy Information Administration, *Annual Energy Review 2011,* DOE/EIA-0384(2011) (Washington, DC, September 2012). **Projections:** AEO2013 National Energy Modeling System, runs REF2013.D102312A, LOWPRICE.D031213A, and HIGHPRICE.D110912A.

**Figure 22. World petroleum and other liquids supply in three cases, 1990-2040: History:** U.S. Energy Information Administration, *Annual Energy Review 2011,* DOE/EIA-0384(2011) (Washington, DC, September 2012). **Projections:** AEO2013 National Energy Modeling System, runs REF2013.D102312A, LOWPRICE.D031213A, and HIGHPRICE.D110912A.

**Figure 23. World petroleum and other liquids supply by source in the Reference case, 1990-2040: History:** U.S. Energy Information Administration, *Annual Energy Review 2011,* DOE/EIA-0384(2011) (Washington, DC, September 2012). **Projections:** AEO2013 National Energy Modeling System, run REF2013.D102312A.

**Figure 24. Net import share of liquid fuels in five cases, 2005-2040: History:** U.S. Energy Information Administration, *Annual Energy Review 2011,* DOE/EIA-0384(2011) (Washington, DC, September 2012). **Projections:** AEO2013 National Energy Modeling System, runs REF2013.D102312A, HIGHIMPORT.D012813A, LOWIMPORT.D021113A, LOWRESOURCE.D012813A, and HIGHRESOURCE.D021413A.

**Figure 25. U.S. carbon dioxide emissions in five cases, 2005-2040: History:** U.S. Energy Information Administration, *Annual Energy Review 2011,* DOE/EIA-0384(2011) (Washington, DC, September 2012). **Projections:** AEO2013 National Energy Modeling System, runs REF2013.D102312A, HIGHIMPORT.D012813A, LOWIMPORT.D021113A, LOWRESOURCE.D012813A, and HIGHRESOURCE.D021413A.

**Figure 26. Average delivered fuel prices to electric power plants, 2008-2040: History:** U.S. Energy Information Administration, *Annual Energy Review 2011,* DOE/EIA-0384(2011) (Washington, DC, September 2012). **Projections:** AEO2013 National Energy Modeling System, run REF2013.D102312A.

**Figure 27. Ratio of average per megawatthour fuel costs for natural gas combined-cycle plants to coal-fired steam turbines in five cases, 2008-2040: History:** U.S. Energy Information Administration, *Annual Energy Review 2011,* DOE/EIA-0384(2011) (Washington, DC, September 2012). **Projections:** AEO2013 National Energy Modeling System, runs REF2013.D102312A, LOWRESOURCE.D012813A, HIGHRESOURCE.D021413A, LCCST13.D112112A, and HCCST13.D112112A.

**Figure 28. Power sector electricity generation capacity by fuel in five cases, 2011 and 2025: History:** U.S. Energy Information Administration, *Annual Energy Review 2011,* DOE/EIA-0384(2011) (Washington, DC, September 2012). **Projections:** AEO2013 National Energy Modeling System, runs REF2013.D102312A, LOWRESOURCE.D012813A, HIGHRESOURCE.D021413A, LCCST13.D112112A, and HCCST13.D112112A.

**Figure 29. Power sector electricity generation capacity by fuel in five cases, 2011 and 2040: History:** U.S. Energy Information Administration, *Annual Energy Review 2011,* DOE/EIA-0384(2011) (Washington, DC, September 2012). **Projections:** AEO2013 National Energy Modeling System, runs REF2013.D102312A, LOWRESOURCE.D012813A, HIGHRESOURCE.D021413A, LCCST13.D112112A, and HCCST13.D112112A.

**Figure 30. Power sector electricity generation by fuel in five cases, 2011 and 2025: History:** U.S. Energy Information Administration, *Annual Energy Review 2011,* DOE/EIA-0384(2011) (Washington, DC, September 2012). **Projections:** AEO2013 National Energy Modeling System, runs REF2013.D102312A, LOWRESOURCE.D012813A, HIGHRESOURCE.D021413A, LCCST13.D112112A, and HCCST13.D112112A.

**Figure 31. Power sector electricity generation by fuel in five cases, 2011 and 2040: History:** U.S. Energy Information Administration, *Annual Energy Review 2011,* DOE/EIA-0384(2011) (Washington, DC, September 2012). **Projections:** AEO2013 National Energy Modeling System, runs REF2013.D102312A, LOWRESOURCE.D012813A, HIGHRESOURCE.D021413A, LCCST13.D112112A, and HCCST13.D112112A.

**Figure 32. Power sector electricity generation from coal and natural gas in two cases, 2008-2040: History:** U.S. Energy Information Administration, *Annual Energy Review 2011,* DOE/EIA-0384(2011) (Washington, DC, September 2012). **Projections:** AEO2013 National Energy Modeling System, runs REF2013.D102312A and HIGHRESOURCE.D021413A.

**Figure 33. Ratio of average per megawatthour fuel costs for natural gas combined-cycle plants to coal-fired steam turbines in the SERC southeast subregion in five cases, 2008-2040: History:** U.S. Energy Information Administration, *Annual Energy Review 2011,* DOE/EIA-0384(2011) (Washington, DC, September 2012). **Projections:** AEO2013 National Energy Modeling System, runs REF2013.D102312A, LOWRESOURCE.D012813A, HIGHRESOURCE.D021413A, LCCST13.D112112A, and HCCST13.D112112A.

**Figure 34. Ratio of average per megawatthour fuel costs for natural gas combined-cycle plants to coal-fired steam turbines in the RFC west subregion in five cases, 2008-2040: History:** U.S. Energy Information Administration, *Annual Energy Review 2011,* DOE/EIA-0384(2011) (Washington, DC, September 2012). **Projections:** AEO2013 National Energy Modeling System, runs REF2013.D102312A, LOWRESOURCE.D012813A, HIGHRESOURCE.D021413A, LCCST13.D112112A, and HCCST13.D112112A.

**Figure 35. Nuclear capacity additions in five cases, 2011-2040: Projections:** AEO2013 National Energy Modeling System, runs REF2013.D102312A, LOWNUC13.D112113A, HINUC13.D112112A, LOWRESOURCE.D012813A, and HIGHRESOURCE.D021413A.

**Figure 36. Electricity generation from natural gas in three cases, 2005-2040: History:** U.S. Energy Information Administration, *Annual Energy Review 2011,* DOE/EIA-0384(2011) (Washington, DC, September 2012). **Projections:** AEO2013 National Energy Modeling System, runs REF2013.D102312A, LOWNUC13.D112113A, and HINUC13.D112112A.

**Figure 37. Carbon dioxide emissions from electricity generation in three cases, 2005-2040: History:** U.S. Energy Information Administration, *Annual Energy Review 2011,* DOE/EIA-0384(2011) (Washington, DC, September 2012). **Projections:** AEO2013 National Energy Modeling System, runs REF2013.D102312A, LOWNUC13.D112113A, and HINUC13.D112112A.

**Figure 38. Levelized costs of nuclear electricity generation in two cases, 2025: Projections:** AEO2013 National Energy Modeling System, runs REF2013.D102312A and NUCSMR13.D112712A.

**Figure 39. U.S. production of natural gas liquids by type, 2005-2012: History:** U.S. Energy Information Administration, *Petroleum Supply Monthly,* January 2013, http://www.eia.gov/dnav/pet/pet_sum_snd_d_nus_mbblpd_a_cur.htm.

**Figure 40. U.S. imports and exports of propane/propylene, 2005-2012: History:** U.S. Energy Information Administration, *Petroleum Supply Monthly,* January 2013, http://www.eia.gov/dnav/pet/pet_sum_snd_d_nus_mbblpd_a_cur.htm.

**Figure 41. U.S. Brent crude oil and Henry Hub natural gas spot market prices in three cases, 2005-2040: History:** U.S. Energy Information Administration, *Annual Energy Review 2011,* DOE/EIA-0384(2011) (Washington, DC, September 2012). **Projections:** AEO2013 National Energy Modeling System, runs REF2013.D102312A, LOWRESOURCE.D012813A, and HIGHRESOURCE.D021413A.

**Figure 42. U.S. production of dry natural gas and natural gas plant liquids in three cases, 2005-2040: History:** U.S. Energy Information Administration, *Annual Energy Review 2011,* DOE/EIA-0384(2011) (Washington, DC, September 2012). **Projections:** AEO2013 National Energy Modeling System, runs REF2013.D102312A, LOWRESOURCE.D012813A, and HIGHRESOURCE.D021413A.

**Figure 43. U.S. net exports of liquefied petroleum gases in three cases, 2011-2040: History:** U.S. Energy Information Administration, *Annual Energy Review 2011,* DOE/EIA-0384(2011) (Washington, DC, September 2012). **Projections:** AEO2013 National Energy Modeling System, runs REF2013.D102312A, LOWRESOURCE.D012813A, and HIGHRESOURCE.D021413A.

## Market Trends

**Figure 44. Average annual growth rates of real GDP, labor force, and productivity in three cases, 2011-2040: Projections:** AEO2013 National Energy Modeling System, runs REF2013.D102312A, LOWMACRO.D110912A, and HIGHMACRO.D110912A.

**Figure 45. Average annual growth rates for real output and its major components in three cases, 2011-2040: History:** Bureau of Economic Analysis. **Projections:** AEO2013 National Energy Modeling System, runs REF2013.D102312A, LOWMACRO.D110912A, and HIGHMACRO.D110912A.

**Figure 46. Sectoral composition of industrial shipments, annual growth rates in three cases, 2011-2040: Projections:** AEO2013 National Energy Modeling System, runs REF2013.D102312A, LOWMACRO.D110912A, and HIGHMACRO.D110912A.

**Figure 47. Energy end-use expenditures as a share of gross domestic product, 1970-2040: History:** U.S. Energy Information Administration, *Annual Energy Review 2011,* DOE/EIA-0384(2011) (Washington, DC, September 2012). **Projections:** AEO2013 National Energy Modeling System, run REF2013.D102312A.

**Figure 48. Energy end-use expenditures as a share of gross output, 1987-2040: History:** U.S. Energy Information Administration, *Annual Energy Review 2011,* DOE/EIA-0384(2011) (Washington, DC, September 2012). **Projections:** AEO2013 National Energy Modeling System, run REF2013.D102312A.

**Figure 49. Brent crude oil spot prices in three cases, 1990-2040: History:** U.S. Energy Information Administration, *Petroleum & Other Liquids, Europe Bent Spot Price FOB,* http://www.eia.gov/dnav/pet/hist/LeafHandler.ashx?n=PET&s=RBRTE&f=D. **Projections:** AEO2013 National Energy Modeling System, runs REF2013.D102312A, LOWPRICE.D031213A, and HIGHPRICE.D110912A.

**Figure 50. World petroleum and other liquids consumption by region in three cases, 2011 and 2040: History:** U.S. Energy Information Administration, *Annual Energy Review 2011,* DOE/EIA-0384(2011) (Washington, DC, September 2012). **Projections:** AEO2013 National Energy Modeling System, runs REF2013.D102312A LOWPRICE.D031213A, and HIGHPRICE.D110912A.

**Figure 51. World production of liquids from biomass, coal, and natural gas in three cases, 2011 and 2040: Projections:** AEO2013 National Energy Modeling System, runs REF2013.D102312A LOWPRICE.D031213A, and HIGHPRICE.D110912A.

**Figure 52. Energy use per capita and per dollar of gross domestic product, 1980-2040: History:** U.S. Energy Information Administration, *Annual Energy Review 2011,* DOE/EIA-0384(2011) (Washington, DC, September 2012). **Projections:** AEO2013 National Energy Modeling System, run REF2013.D102312A.

**Figure 53. Primary energy use by end-use sector, 2011-2040: History:** U.S. Energy Information Administration, *Annual Energy Review 2011,* DOE/EIA-0384(2011) (Washington, DC, September 2012). **Projections:** AEO2013 National Energy Modeling System, run REF2013.D102312A.

**Figure 54. Primary energy use by fuel, 1980-2040: History:** U.S. Energy Information Administration, *Annual Energy Review 2011,* DOE/EIA-0384(2011) (Washington, DC, September 2012). **Projections:** AEO2013 National Energy Modeling System, run REF2013.D102312A.

**Figure 55. Residential delivered energy intensity in four cases, 2005-2040: History:** U.S. Energy Information Administration, *Annual Energy Review 2011,* DOE/EIA-0384(2011) (Washington, DC, September 2012). **Projections:** AEO2013 National Energy Modeling System, runs REF2013.D102312A, FROZTECH.D120712A, HIGHTECH.D120712A, and BESTTECH.D121012A.

**Figure 56. Change in residential electricity consumption for selected end uses in the Reference case, 2011-2040: Projections:** AEO2013 National Energy Modeling System, run REF2013.D102312A.

**Figure 57. Change in residential delivered energy consumption for selected end uses in four cases, 2011-2040: Projections:** AEO2013 National Energy Modeling System, runs REF2013.D102312A, EXTENDED.D010313A, HIGHTECH.D120712A, and BESTTECH.D121012A.

**Figure 58. Residential sector adoption of renewable energy technologies in two cases, 2005-2040: History:** U.S. Energy Information Administration, *Annual Energy Review 2011,* DOE/EIA-0384(2011) (Washington, DC, September 2012), American Wind Energy Association, and Interstate Renewable Energy Council. **Projections:** AEO2013 National Energy Modeling System, runs REF2013.D102312A and NOSUNSET.D120712A.

**Figure 59. Commercial delivered energy intensity in four cases, 2005-2040: History:** U.S. Energy Information Administration, *Annual Energy Review 2011,* DOE/EIA-0384(2011) (Washington, DC, September 2012). **Projections:** AEO2013 National Energy Modeling System, runs REF2013.D102312A, FROZTECH.D120712A, HIGHTECH.D120712A, and BESTTECH.D121012A.

**Figure 60. Energy intensity of selected commercial electric end uses, 2011 and 2040: Projections:** AEO2013 National Energy Modeling System, run REF2013.D102312A.

**Figure 61. Efficiency gains for selected commercial equipment in three cases, 2040: Projections:** AEO2013 National Energy Modeling System, runs REF2013.D102312A, FROZTECH.D120712A, and BESTTECH.D121012A.

**Figure 62. Additions to electricity generation capacity in the commercial sector in two cases, 2011-2040: Projections:** AEO2013 National Energy Modeling System, runs REF2013.D102312A and EXTENDED.D010313A.

**Figure 63. Industrial delivered energy consumption by application, 2011-2040: Projections:** AEO2013 National Energy Modeling System, run REF2013.D102312A.

**Figure 64. Industrial energy consumption by fuel, 2011, 2025, and 2040: Projections:** AEO2013 National Energy Modeling System, run REF2013.D102312A.

**Figure 65. Cumulative growth in value of shipments from energy-intensive industries in three cases, 2011-2040: Projections:** AEO2013 National Energy Modeling System, runs REF2013.D102312A, LOWMACRO.D110912A, and HIGHMACRO.D110912A.

**Figure 66. Change in delivered energy consumption for energy-intensive industries in three cases, 2011-2040: Projections:** AEO2013 National Energy Modeling System, runs REF2013.D102312A, LOWMACRO.D110912A, and HIGHMACRO.D110912A.

**Figure 67. Cumulative growth in value of shipments from energy-intensive industries, 2011-2040, 2011-2025, and 2025-2040: Projections:** AEO2013 National Energy Modeling System, run REF2013.D102312A.

**Figure 68. Cumulative growth in value of shipments from non-energy-intensive industries in three cases, 2011-2040: Projections:** AEO2013 National Energy Modeling System, runs REF2013.D102312A, LOWMACRO.D110912A, and HIGHMACRO.D110912A.

**Figure 69. Change in delivered energy consumption for non-energy-intensive industries in three cases, 2011-2040: Projections:** AEO2013 National Energy Modeling System, runs REF2013.D102312A, LOWMACRO.D110912A, and HIGHMACRO.D110912A.

**Figure 70. Delivered energy consumption for transportation by mode, 2011 and 2040: Projections:** AEO2013 National Energy Modeling System, run REF2013.D102312A.

**Figure 71. Average fuel economy of new light-duty vehicles, 1980-2040: History:** S.C. Davis, S.W. Diegel, and R.G. Boundy, *Transportation Energy Databook: Edition 31,* ORNL-6987 (Oak Ridge, TN: July 2012), Chapter 4, Table 4.21 "Car Corporate Average Fuel Economy (CAFE) Standards versus Sales-Weighted Fuel Economy Estimates, 1978-2011 (miles per gallon)." **Projections:** AEO2013 National Energy Modeling System, run REF2013.D102312A.

**Figure 72. Vehicle miles traveled per licensed driver, 1970-2040: History:** U.S. Department of Transportation, Federal Highway Administration, *Highway Statistics 2010* (Washington, DC: 2012), http://www.fhwa.dot.gov/policyinformation/statistics/2010/. Projections: AEO2013 National Energy Modeling System, run REF2013.D102312A.

**Figure 73. Sales of light-duty vehicles using non-gasoline technologies by type, 2011, 2025, and 2040: Projections:** AEO2013 National Energy Modeling System, run REF2013.D102312A.

**Figure 74. Natural gas consumption in the transportation sector, 1995-2040: History:** Oak Ridge National Laboratory, *Transportation Energy Data Book: Edition 30* (Oak Ridge, TN, 2011), http://cta.ornl.gov/data/index.shtml. **Projections:** AEO2013 National Energy Modeling System, run REF2013.D102312A.

**Figure 75. U.S. electricity demand growth, 1950-2040: History:** U.S. Energy Information Administration, *Annual Energy Review 2011,* DOE/EIA-0384(2011) (Washington, DC, September 2012). **Projections:** AEO2013 National Energy Modeling System, run REF2013.D102312A.

**Figure 76. Electricity generation by fuel, 2011, 2025, and 2040: Projections:** AEO2013 National Energy Modeling System, run REF2013.D102312A.

**Figure 77. Electricity generation capacity additions by fuel type, including combined heat and power, 2012-2040: Projections:** AEO2013 National Energy Modeling System, run REF2013.D102312A.

**Figure 78. Additions to electricity generating capacity, 1985-2040: History:** Energy Information Administration, Form EIA-860, "Annual Electric Generator Report." **Projections:** AEO2013 National Energy Modeling System, run REF2013.D102312A.

**Figure 79. Electricity sales and power sector generating capacity, 1949-2040: History:** U.S. Energy Information Administration, *Annual Energy Review 2011,* DOE/EIA-0384(2011) (Washington, DC, September 2012). **Projections:** AEO2013 National Energy Modeling System, run REF2013.D102312A.

**Figure 80. Levelized electricity costs for new power plants, excluding subsidies, 2020 and 2040: Projections:** AEO2013 National Energy Modeling System, run REF2013.D102312A.

**Figure 81. Electricity generating capacity at U.S. nuclear power plants in three cases, 2011, 2025, and 2040: Projections:** AEO2013 National Energy Modeling System, runs REF2013.D102312A, LOWMACRO.D110912A, and HIGHMACRO.D110912A.

**Figure 82. Renewable electricity generation capacity by energy source, including end-use capacity, 2011-2040: Projections:** AEO2013 National Energy Modeling System, run REF2013.D102312A.

**Figure 83. Renewable electricity generation by type, including end-use generation, 2008-2040: History:** U.S. Energy Information Administration, *Annual Energy Review 2011,* DOE/EIA-0384(2011) (Washington, DC, September 2012). **Projections:** AEO2013 National Energy Modeling System, run REF2013.D102312A.

**Figure 84. Regional nonhydropower renewable electricity generation, including end-use generation, 2011 and 2040: Projections:** AEO2013 National Energy Modeling System, run REF2013.D102312A.

**Figure 85. Natural gas consumption by sector, 1990-2040: History:** U.S. Energy Information Administration, *Annual Energy Review 2011,* DOE/EIA-0384(2011) (Washington, DC, September 2012). **Projections:** AEO2013 National Energy Modeling System, run REF2013.D102312A.

**Figure 86. Annual average Henry Hub spot natural gas prices, 1990-2040: History:** U.S. Energy Information Administration, *Natural Gas Annual 2011,* DOE/EIA-0131(2011) (Washington, DC, January 2013). **Projections:** AEO2013 National Energy Modeling System, run REF2013.D102312A.

**Figure 87. Ratio of Brent crude oil price to Henry Hub spot natural gas price in energy-equivalent terms, 1990-2040: History:** U.S. Energy Information Administration, *Short-Term Energy Outlook* Query System, Monthly Natural Gas Data, Variable NGHHUUS. **Projections:** AEO2013 National Energy Modeling System, run REF2013.D102312A.

**Figure 88. Annual average Henry Hub spot prices for natural gas in five cases, 1990-2040: History:** U.S. Energy Information Administration, *Natural Gas Annual 2011,* DOE/EIA-0131(2011) (Washington, DC, January 2013). **Projections:** AEO2013 National Energy Modeling System, runs REF2013.D102312A, LOWMACRO.D110912A, HIGHMACRO.D110912A, LOWRESOURCE.D012813A, and HIGHRESOURCE.D021413A.

**Figure 89. Total U.S. natural gas production, consumption, and net imports, 1990-2040: History:** U.S. Energy Information Administration, *Natural Gas Annual 2011,* DOE/EIA-0131(2011) (Washington, DC, January 2013). **Projections:** AEO2013 National Energy Modeling System, run REF2013.D102312A.

**Figure 90. Total U.S. natural gas production in three oil price cases, 1990-2040: History:** U.S. Energy Information Administration, *Natural Gas Annual 2011,* DOE/EIA-0131(2011) (Washington, DC, January 2013). **Projections:** AEO2013 National Energy Modeling System, runs REF2013.D102312A, LOWPRICE.D031213A, and HIGHPRICE.D110912A.

**Figure 91. Natural gas production by source, 1990-2040: History:** U.S. Energy Information Administration, *Natural Gas Annual 2011,* DOE/EIA-0131(2011) (Washington, DC, January 2013). **Projections:** AEO2013 National Energy Modeling System, run REF2013.D102312A.

**Figure 92. U.S. net imports of natural gas by source, 1990-2040: History:** U.S. Energy Information Administration, *Natural Gas Annual 2011,* DOE/EIA-0131(2011) (Washington, DC, January 2013). **Projections:** AEO2013 National Energy Modeling System, run REF2013.D102312A.

**Figure 93. Consumption of petroleum and other liquids by sector, 1990-2040: History:** U.S. Energy Information Administration, *Annual Energy Review 2011,* DOE/EIA-0384(2011) (Washington, DC, September 2012). **Projections:** AEO2013 National Energy Modeling System, run REF2013.D102312A.

**Figure 94. U.S. production of petroleum and other liquids by source, 2011-2040: Projections:** AEO2013 National Energy Modeling System, run REF2013.D102312A.

**Figure 95. Total U.S. crude oil production in three resource cases, 1990-2040: History:** U.S. Energy Information Administration, *Annual Energy Review 2011,* DOE/EIA-0384(2011) (Washington, DC, September 2012). **Projections:** AEO2013 National Energy Modeling System, runs REF2013.D102312A, LOWRESOURCE.D012813A, and HIGHRESOURCE.D021413A.

**Figure 96. Domestic crude oil production by source, 2000-2040: History:** U.S. Energy Information Administration, *Annual Energy Review 2011,* DOE/EIA-0384(2011), Table 5.2, (Washington, DC, September 2011). **Projections:** AEO2013 National Energy Modeling System, run REF2013.D102312A.

**Figure 97. Total U.S. tight oil production by geologic formation, 2008-2040: History:** Drilling Info (formerly HPDI), Texas RRC, North Dakota department of mineral resources. **Projections:** AEO2013 National Energy Modeling System, run REF2013.D102312A.

**Figure 98. API gravity of U.S. domestic and imported crude oil supplies, 1990-2040: History:** U.S. Energy Information Administration, Crude Oil Input Qualities and Company Level Imports Archives, http://www.eia.gov/petroleum/imports/companylevel/archive/. **Projections:** AEO2013 National Energy Modeling System, run REF2013.D102312A.

**Figure 99. Net import share of U.S. petroleum and other liquids consumption in three oil price cases, 1990-2040: History:** U.S. Energy Information Administration, *Annual Energy Review 2011,* DOE/EIA-0384(2011) (Washington, DC, September 2012). **Projections:** AEO2013 National Energy Modeling System, runs REF2013.D102312A, LOWPRICE.D031213A, and HIGHPRICE.D110912A.

**Figure 100. EISA2007 RFS credits earned in selected years, 2011-2040: Projections:** AEO2013 National Energy Modeling System, run REF2013.D102312A.

**Figure 101. Consumption of advanced renewable fuels, 2011-2040: Projections:** AEO2013 National Energy Modeling System, run REF2013.D102312A.

**Figure 102. U.S. motor gasoline and diesel fuel consumption, 2000-2040: History:** U.S. Energy Information Administration, *Annual Energy Review 2011,* DOE/EIA-0384(2011) (Washington, DC, September 2012). **Projections:** AEO2013 National Energy Modeling System, run REF2013.D102312A.

**Figure 103. U.S. refinery gasoline-to-diesel production ratio and crack spread, 2008-2040: History:** 2008-2010: Crack spread calculated from national average wholesale prices for diesel fuel and gasoline blend components (RBOB) and historical crude prices. Wholesale prices calculated from historical end use prices and distributor/tax markups. Oil and Gas Information Reporting System (OGIRS). **2011:** U.S. Energy Information Administration, *EIA Today In Energy* (October 31, 2011), "3:2:1 crack spreads based on WTI & LLS crude oils have diverged in 2011," http://www.eia.gov/todayinenergy/detail.cfm?id=3710. **2008-2011:** Gasoline and diesel refinery production calculated as the difference of historical consumption levels and corresponding non-petroleum components (ethanol, biodiesel). Oil and Gas Information Reporting System (OGIRS). **Projections:** AEO2013 National Energy Modeling System, run REF2013.D102312A.

**Figure 104. Coal production by region, 1970-2040: History (short tons): 1970-1990:** U.S. Energy Information Administration, *The U.S. Coal Industry, 1970-1990: Two Decades of Change,* DOE/EIA-0559 (Washington, DC, November 2002). **1991-2000:** U.S. Energy Information Administration, *Coal Industry Annual,* DOE/EIA-0584 (various years). **2001-2011:** U.S. Energy Information Administration, *Annual Coal Report 2011,* DOE/EIA-0584(2011) (Washington, DC, November 2012), and previous issues. **History (conversion to quadrillion Btu): 1970-2010: Estimation Procedure:** Estimates of average heat content by region and year are based on coal quality data collected through various energy surveys (see sources) and national-level estimates of U.S. coal production by year in units of quadrillion Btu, published in EIA's *Annual Energy Review.* **Sources:** U.S. Energy Information Administration, *Annual Energy Review 2011,* DOE/EIA-0384(2011) (Washington, DC, September 2012), Table 1.2; Form EIA-3, "Quarterly Coal Consumption and Quality Report, Manufacturing and Transformation/Processing Coal Plants and Commercial and Institutional Coal Users"; Form EIA-5, "Quarterly Coal Consumption and Quality Report, Coke Plants"; Form EIA-6A, "Coal Distribution Report"; Form EIA-7A, "Annual Coal Production and Preparation Report"; Form EIA-423, "Monthly Cost and Quality of Fuels for Electric Plants Report"; Form EIA-906, "Power Plant Report"; Form EIA-920, "Combined Heat and Power Plant Report"; Form EIA-923, "Power Plant Operations Report"; U.S. Department of Commerce, Bureau of the Census, "Monthly Report EM 545"; and Federal Energy Regulatory Commission, Form 423, "Monthly Report of Cost and Quality of Fuels for Electric Plants." **Projections:** AEO2013 National Energy Modeling System, run REF2013.D102312A. **Note:** For 1989-2035, coal production includes waste coal.

**Figure 105. U.S. total coal production in six cases, 2011, 2020, and 2040: Projections:** AEO2013 National Energy Modeling System, runs REF2013.D102312A, LCCST13.D112112A, HCCST13.D112112A, LOWRESOURCE.D012813A, HIGHRESOURCE.D021413A, and CO2FEE15.D021413A. **Note:** Coal production includes waste coal.

**Figure 106. Average annual minemouth coal prices by region, 1990-2040: History (dollars per short ton): 1990-2000:** U.S. Energy Information Administration, *Coal Industry Annual,* DOE/EIA-0584 (various years). **2001-2011:** U.S. Energy Information Administration, *Annual Coal Report 2011,* DOE/EIA-0584(2011) (Washington, DC, November 2012), and previous issues. **History (conversion to dollars per million Btu): 1970-2011: Estimation Procedure:** Estimates of average heat content by region and year based on coal quality data collected through various energy surveys (see sources) and national-level estimates of U.S. coal production by year in units of quadrillion Btu published in EIA's *Annual Energy Review.* **Sources:** U.S. Energy Information Administration, *Annual Energy Review 2011,* DOE/EIA-0384(2011) (Washington, DC, September 2012), Table 1.2; Form EIA-3, "Quarterly Coal Consumption and Quality Report, Manufacturing and Transformation/Processing Coal Plants and Commercial and Institutional Coal Users"; Form EIA-5, "Quarterly Coal Consumption and Quality Report, Coke Plants"; Form EIA-6A, "Coal Distribution Report"; Form EIA-7A, "Annual Coal Production and Preparation Report"; Form EIA-423, "Monthly Cost and Quality of Fuels for Electric Plants Report"; Form EIA-906, "Power Plant Report"; Form EIA-920, "Combined Heat and Power Plant Report"; Form EIA-923, "Power Plant Operations Report"; U.S. Department of Commerce, Bureau of the Census, "Monthly Report EM 545"; and Federal Energy Regulatory Commission, Form 423, "Monthly Report of Cost and Quality of Fuels for Electric Plants." **Projections:** AEO2013 National Energy Modeling System, run REF2013.D102312A. **Note:** Includes reported prices for both open-market and captive mines.

**Figure 107. Cumulative coal-fired generating capacity additions and environmental retrofits in two cases, 2012-2040: Projections:** AEO2013 National Energy Modeling System, runs REF2013.D102312A and NOGHGCONCERN.D110912A.

**Figure 108. U.S. energy-related carbon dioxide emissions by sector and fuel, 2005 and 2040: History:** U.S. Energy Information Administration, *Monthly Energy Review,* March, 2013, DOE/EIA-0035(2013/03). **Projections:** AEO2013 National Energy Modeling System, run REF2013.D102312A.

**Figure 109. Sulfur dioxide emissions from electricity generation, 1990-2040: History:** U.S. Environmental Protection Agency, *Clean Air Interstate Rule, Acid Rain Program, and Former $NO_X$ Budget Trading Program 2011 Progress Report,* http://www.epa.gov/airmarkets/progress/ARPCAIR11_01.html#qualityassurance. **Projections:** AEO2013 National Energy Modeling System, run REF2013.D102312A.

**Figure 110. Nitrogen oxides emissions from electricity generation, 1990-2040: History:** U.S. Environmental Protection Agency, *Clean Air Interstate Rule, Acid Rain Program, and Former $NO_X$ Budget Trading Program 2011 Progress Report,* http://www.epa.gov/airmarkets/progress/ARPCAIR11_01.html#qualityassurance. **Projections:** AEO2013 National Energy Modeling System, run REF2013.D102312A.

**Figure 111. Energy-related carbon dioxide emissions in two cases with three levels of emissions fees, 2000-2040: History:** U.S. Energy Information Administration, *Annual Energy Review 2011,* DOE/EIA-0384(2011) (Washington, DC, September 2012). **Projections:** AEO2013 National Energy Modeling System, runs REF2013.D102312A, HIGHRESOURCE.D021413A, CO2FEE10.D021413A, CO2FEE15.D021413A, CO2FEE25.D021413A, CO2FEE10HR.D021413A, CO2FEE15HR.D021413A, and CO2FEE25HR.D021413A.

**Figure 112. Natural gas-fired electricity generation in six $CO_2$ fee cases, 2000-2040: History:** U.S. Energy Information Administration, *Annual Energy Review 2011,* DOE/EIA-0384(2011) (Washington, DC, September 2012). **Projections:** AEO2013 National Energy Modeling System, runs REF2013.D102312A, HIGHRESOURCE.D021413A, CO2FEE10.D021413A, CO2FEE15.D021413A, CO2FEE25.D021413A, CO2FEE10HR.D021413A, CO2FEE15HR.D021413A, and CO2FEE25HR.D021413A.

# Reference case

## Table A1. Total energy supply, disposition, and price summary
(quadrillion Btu per year, unless otherwise noted)

| Supply, disposition, and prices | Reference case | | | | | | | Annual growth 2011-2040 (percent) |
|---|---|---|---|---|---|---|---|---|
| | 2010 | 2011 | 2020 | 2025 | 2030 | 2035 | 2040 | |
| **Production** | | | | | | | | |
| Crude oil and lease condensate | 11.59 | 12.16 | 15.95 | 14.50 | 13.47 | 13.40 | 13.12 | 0.3% |
| Natural gas plant liquids | 2.78 | 2.88 | 4.14 | 4.20 | 3.85 | 3.87 | 3.89 | 1.0% |
| Dry natural gas | 21.82 | 23.51 | 27.19 | 29.22 | 30.44 | 32.04 | 33.87 | 1.3% |
| Coal[1] | 22.04 | 22.21 | 21.74 | 22.54 | 23.25 | 23.60 | 23.54 | 0.2% |
| Nuclear / uranium[2] | 8.43 | 8.26 | 9.25 | 9.54 | 9.49 | 9.14 | 9.44 | 0.5% |
| Hydropower | 2.54 | 3.17 | 2.83 | 2.86 | 2.87 | 2.90 | 2.92 | -0.3% |
| Biomass[3] | 4.05 | 4.05 | 5.00 | 5.27 | 5.42 | 5.83 | 6.96 | 1.9% |
| Other renewable energy[4] | 1.31 | 1.58 | 2.22 | 2.32 | 2.50 | 2.91 | 3.84 | 3.1% |
| Other[5] | 0.76 | 1.20 | 0.83 | 0.85 | 0.88 | 0.90 | 0.89 | -1.0% |
| **Total** | **75.31** | **79.02** | **89.16** | **91.29** | **92.18** | **94.59** | **98.46** | **0.8%** |
| **Imports** | | | | | | | | |
| Crude oil | 20.14 | 19.46 | 15.02 | 15.57 | 16.33 | 16.43 | 16.89 | -0.5% |
| Liquid fuels and other petroleum[6] | 5.26 | 5.24 | 5.55 | 5.47 | 5.33 | 5.13 | 4.82 | -0.3% |
| Natural gas[7] | 3.83 | 3.54 | 2.58 | 2.36 | 2.63 | 2.53 | 2.01 | -1.9% |
| Other imports[8] | 0.52 | 0.43 | 0.11 | 0.17 | 0.13 | 0.48 | 0.84 | 2.4% |
| **Total** | **29.75** | **28.66** | **23.26** | **23.57** | **24.41** | **24.57** | **24.55** | **-0.5%** |
| **Exports** | | | | | | | | |
| Liquid fuels and other petroleum[9] | 4.86 | 6.08 | 5.37 | 5.14 | 5.25 | 5.55 | 5.71 | -0.2% |
| Natural gas[10] | 1.15 | 1.52 | 2.67 | 3.92 | 4.71 | 5.07 | 5.56 | 4.6% |
| Coal | 2.10 | 2.75 | 3.13 | 3.18 | 3.51 | 3.80 | 3.79 | 1.1% |
| **Total** | **8.11** | **10.35** | **11.17** | **12.25** | **13.47** | **14.42** | **15.06** | **1.3%** |
| **Discrepancy[11]** | **-1.40** | **-0.36** | **0.21** | **0.27** | **0.30** | **0.32** | **0.32** | **- -** |
| **Consumption** | | | | | | | | |
| Liquid fuels and other petroleum[12] | 37.76 | 37.02 | 37.54 | 36.87 | 36.08 | 35.82 | 36.07 | -0.1% |
| Natural gas | 24.32 | 24.91 | 26.77 | 27.28 | 27.95 | 29.06 | 29.83 | 0.6% |
| Coal[13] | 20.81 | 19.66 | 18.59 | 19.35 | 19.70 | 20.09 | 20.35 | 0.1% |
| Nuclear / uranium[2] | 8.43 | 8.26 | 9.25 | 9.54 | 9.49 | 9.14 | 9.44 | 0.5% |
| Hydropower | 2.54 | 3.17 | 2.83 | 2.86 | 2.87 | 2.90 | 2.92 | -0.3% |
| Biomass[14] | 2.87 | 2.74 | 3.53 | 3.82 | 3.94 | 4.23 | 4.91 | 2.0% |
| Other renewable energy[4] | 1.31 | 1.58 | 2.22 | 2.32 | 2.50 | 2.91 | 3.84 | 3.1% |
| Other[15] | 0.31 | 0.35 | 0.31 | 0.30 | 0.28 | 0.26 | 0.29 | -0.6% |
| **Total** | **98.35** | **97.70** | **101.04** | **102.34** | **102.81** | **104.41** | **107.64** | **0.3%** |
| **Prices (2011 dollars per unit)** | | | | | | | | |
| Crude oil spot prices (dollars per barrel) | | | | | | | | |
| Brent | 81.31 | 111.26 | 105.57 | 117.36 | 130.47 | 145.41 | 162.68 | 1.3% |
| West Texas Intermediate | 81.08 | 94.86 | 103.57 | 115.36 | 128.47 | 143.41 | 160.68 | 1.8% |
| Natural gas at Henry Hub (dollars per million Btu) | 4.46 | 3.98 | 4.13 | 4.87 | 5.40 | 6.32 | 7.83 | 2.4% |
| Coal (dollars per ton) | | | | | | | | |
| at the minemouth[16] | 36.37 | 41.16 | 49.26 | 52.02 | 55.64 | 58.57 | 61.28 | 1.4% |
| Coal (dollars per million Btu) | | | | | | | | |
| at the minemouth[16] | 1.80 | 2.04 | 2.45 | 2.60 | 2.79 | 2.94 | 3.08 | 1.4% |
| Average end-use[17] | 2.42 | 2.57 | 2.77 | 2.94 | 3.10 | 3.25 | 3.42 | 1.0% |
| Average electricity (cents per kilowatthour) | 10.0 | 9.9 | 9.4 | 9.5 | 9.7 | 10.1 | 10.8 | 0.3% |

## Table A1. Total energy supply, disposition, and price summary (continued)
(quadrillion Btu per year, unless otherwise noted)

| Supply, disposition, and prices | Reference case | | | | | | | Annual growth 2011-2040 (percent) |
|---|---|---|---|---|---|---|---|---|
| | 2010 | 2011 | 2020 | 2025 | 2030 | 2035 | 2040 | |
| **Prices (nominal dollars per unit)** | | | | | | | | |
| Crude oil spot prices (dollars per barrel) | | | | | | | | |
| Brent | 79.61 | 111.26 | 121.73 | 147.90 | 180.04 | 219.73 | 268.50 | 3.1% |
| West Texas Intermediate | 79.39 | 94.86 | 119.43 | 145.38 | 177.28 | 216.70 | 265.20 | 3.6% |
| Natural gas at Henry Hub (dollars per million Btu) | 4.37 | 3.98 | 4.77 | 6.14 | 7.45 | 9.55 | 12.92 | 4.1% |
| Coal (dollars per ton) | | | | | | | | |
| at the minemouth[16] | 35.61 | 41.16 | 56.81 | 65.55 | 76.78 | 88.51 | 101.14 | 3.1% |
| Coal (dollars per million Btu) | | | | | | | | |
| at the minemouth[16] | 1.76 | 2.04 | 2.83 | 3.27 | 3.85 | 4.44 | 5.08 | 3.2% |
| Average end-use[17] | 2.37 | 2.57 | 3.19 | 3.70 | 4.28 | 4.92 | 5.65 | 2.8% |
| Average electricity (cents per kilowatthour) | 9.8 | 9.9 | 10.8 | 12.0 | 13.4 | 15.2 | 17.8 | 2.0% |

[1]Includes waste coal.
[2]These values represent the energy obtained from uranium when it is used in light water reactors. The total energy content of uranium is much larger, but alternative processes are required to take advantage of it.
[3]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.
[4]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 data.
[5]Includes non-biogenic municipal waste, liquid hydrogen, methanol, and some domestic inputs to refineries.
[6]Includes imports of finished petroleum products, unfinished oils, alcohols, ethers, blending components, and renewable fuels such as ethanol.
[7]Includes imports of liquefied natural gas that are later re-exported.
[8]Includes coal, coal coke (net), and electricity (net). Excludes imports of fuel used in nuclear power plants.
[9]Includes crude oil, petroleum products, ethanol, and biodiesel.
[10]Includes re-exported liquefied natural gas.
[11]Balancing item. Includes unaccounted for supply, losses, gains, and net storage withdrawals.
[12]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.
[13]Excludes coal converted to coal-based synthetic liquids and natural gas.
[14]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.
[15]Includes non-biogenic municipal waste, liquid hydrogen, and net electricity imports.
[16]Includes reported prices for both open market and captive mines. Prices weighted by production, which differs from average minemouth prices published in EIA data reports where it is weighted by reported sales.
[17]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 2010 and 2011 are model results and may differ slightly from official EIA data reports.
**Sources:** 2010 natural gas supply values: U.S. Energy Information Administration (EIA), *Natural Gas Annual 2010*, DOE/EIA-0131(2010) (Washington, DC, December 2011). 2011 natural gas supply values: EIA, *Natural Gas Monthly*, DOE/EIA-0130Natural Gas Monthly, DOE/EIA-0130(2012/07) (Washington, DC, July 2012). 2010 and 2011 natural gas spot price at Henry Hub based on daily data from Natural Gas Intelligence. 2010 and 2011 coal minemouth and delivered coal prices: EIA, *Annual Coal Report 2011*, DOE/EIA-0584(2011) (Washington, DC, November 2012). 2011 petroleum supply values and 2010 crude oil and lease condensate production: EIA, *Petroleum Supply Annual 2011*, DOE/EIA-0340(2011)/1 (Washington, DC, August 2012). Other 2010 petroleum supply values: EIA, *Petroleum Supply Annual 2010*, DOE/EIA-0340(2010)/1 (Washington, DC, July 2011). 2010 and 2011 crude oil spot prices: Thomson Reuters. Other 2010 and 2011 coal values: *Quarterly Coal Report, October-December 2011*, DOE/EIA-0121(2011/4Q) (Washington, DC, March 2012). Other 2010 and 2011 values: EIA, *Annual Energy Review 2011*, DOE/EIA-0384(2011) (Washington, DC, September 2012). **Projections:** EIA, AEO2013 National Energy Modeling System run REF2013.D102312A.

**Table A2. Energy consumption by sector and source**
(quadrillion Btu per year, unless otherwise noted)

| Sector and source | Reference case | | | | | | | Annual growth 2011-2040 (percent) |
|---|---|---|---|---|---|---|---|---|
| | 2010 | 2011 | 2020 | 2025 | 2030 | 2035 | 2040 | |
| **Energy consumption** | | | | | | | | |
| **Residential** | | | | | | | | |
| Propane | 0.53 | 0.53 | 0.52 | 0.52 | 0.52 | 0.52 | 0.52 | -0.0% |
| Kerosene | 0.03 | 0.02 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | -1.8% |
| Distillate fuel oil | 0.58 | 0.59 | 0.51 | 0.45 | 0.40 | 0.36 | 0.32 | -2.1% |
| Liquid fuels and other petroleum subtotal | 1.14 | 1.14 | 1.05 | 0.98 | 0.93 | 0.89 | 0.86 | -1.0% |
| Natural gas | 4.89 | 4.83 | 4.62 | 4.54 | 4.46 | 4.34 | 4.23 | -0.5% |
| Coal | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.00 | -0.9% |
| Renewable energy[1] | 0.44 | 0.45 | 0.44 | 0.44 | 0.45 | 0.45 | 0.45 | 0.1% |
| Electricity | 4.93 | 4.86 | 4.84 | 5.08 | 5.36 | 5.67 | 6.03 | 0.7% |
| **Delivered energy** | **11.41** | **11.28** | **10.95** | **11.04** | **11.20** | **11.35** | **11.57** | **0.1%** |
| Electricity related losses | 10.35 | 10.20 | 9.66 | 10.04 | 10.45 | 10.90 | 11.50 | 0.4% |
| **Total** | **21.76** | **21.48** | **20.62** | **21.08** | **21.65** | **22.25** | **23.08** | **0.2%** |
| **Commercial** | | | | | | | | |
| Propane | 0.14 | 0.14 | 0.16 | 0.16 | 0.16 | 0.17 | 0.17 | 0.7% |
| Motor gasoline[2] | 0.06 | 0.05 | 0.05 | 0.06 | 0.06 | 0.06 | 0.06 | 0.5% |
| Kerosene | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 2.1% |
| Distillate fuel oil | 0.41 | 0.42 | 0.34 | 0.33 | 0.32 | 0.31 | 0.30 | -1.1% |
| Residual fuel oil | 0.08 | 0.07 | 0.09 | 0.09 | 0.09 | 0.09 | 0.09 | 0.6% |
| Liquid fuels and other petroleum subtotal | 0.69 | 0.69 | 0.65 | 0.64 | 0.64 | 0.63 | 0.63 | -0.3% |
| Natural gas | 3.17 | 3.23 | 3.40 | 3.43 | 3.50 | 3.59 | 3.68 | 0.4% |
| Coal | 0.06 | 0.05 | 0.05 | 0.05 | 0.05 | 0.05 | 0.05 | -0.0% |
| Renewable energy[3] | 0.11 | 0.13 | 0.13 | 0.13 | 0.13 | 0.13 | 0.13 | 0.0% |
| Electricity | 4.54 | 4.50 | 4.72 | 4.97 | 5.22 | 5.47 | 5.72 | 0.8% |
| **Delivered energy** | **8.57** | **8.60** | **8.95** | **9.22** | **9.54** | **9.86** | **10.21** | **0.6%** |
| Electricity related losses | 9.52 | 9.45 | 9.42 | 9.82 | 10.18 | 10.51 | 10.92 | 0.5% |
| **Total** | **18.09** | **18.05** | **18.37** | **19.04** | **19.72** | **20.37** | **21.13** | **0.5%** |
| **Industrial[4]** | | | | | | | | |
| Liquefied petroleum gases | 2.12 | 2.10 | 2.46 | 2.54 | 2.47 | 2.40 | 2.30 | 0.3% |
| Propylene | 0.41 | 0.40 | 0.56 | 0.56 | 0.52 | 0.49 | 0.46 | 0.6% |
| Motor gasoline[2] | 0.28 | 0.27 | 0.32 | 0.32 | 0.32 | 0.32 | 0.32 | 0.6% |
| Distillate fuel oil | 1.19 | 1.21 | 1.22 | 1.19 | 1.18 | 1.19 | 1.22 | 0.0% |
| Residual fuel oil | 0.12 | 0.11 | 0.11 | 0.11 | 0.11 | 0.11 | 0.11 | -0.1% |
| Petrochemical feedstocks | 0.94 | 0.88 | 1.03 | 1.08 | 1.08 | 1.08 | 1.09 | 0.7% |
| Other petroleum[5] | 3.70 | 3.61 | 3.54 | 3.48 | 3.46 | 3.53 | 3.65 | 0.0% |
| Liquid fuels and other petroleum subtotal | 8.76 | 8.57 | 9.25 | 9.28 | 9.14 | 9.11 | 9.16 | 0.2% |
| Natural gas | 6.67 | 6.92 | 7.86 | 8.00 | 7.97 | 8.02 | 8.08 | 0.5% |
| Natural-gas-to-liquids heat and power | 0.00 | 0.00 | 0.13 | 0.16 | 0.21 | 0.27 | 0.33 | - - |
| Lease and plant fuel[6] | 1.31 | 1.42 | 1.57 | 1.68 | 1.73 | 1.84 | 1.97 | 1.1% |
| Natural gas subtotal | 7.98 | 8.34 | 9.56 | 9.84 | 9.91 | 10.13 | 10.38 | 0.8% |
| Metallurgical coal | 0.55 | 0.56 | 0.60 | 0.58 | 0.52 | 0.48 | 0.46 | -0.7% |
| Other industrial coal | 1.06 | 1.04 | 1.00 | 1.00 | 1.00 | 1.02 | 1.05 | 0.0% |
| Coal-to-liquids heat and power | 0.00 | 0.00 | 0.00 | 0.07 | 0.09 | 0.12 | 0.15 | - - |
| Net coal coke imports | -0.01 | 0.01 | -0.01 | -0.03 | -0.04 | -0.06 | -0.05 | - - |
| Coal subtotal | 1.60 | 1.62 | 1.58 | 1.63 | 1.57 | 1.56 | 1.61 | -0.0% |
| Biofuels heat and coproducts | 0.85 | 0.67 | 0.82 | 0.82 | 0.85 | 0.97 | 1.37 | 2.5% |
| Renewable energy[7] | 1.47 | 1.51 | 1.72 | 1.85 | 1.97 | 2.11 | 2.28 | 1.4% |
| Electricity | 3.31 | 3.33 | 3.95 | 4.05 | 3.96 | 3.90 | 3.91 | 0.6% |
| **Delivered energy** | **23.98** | **24.04** | **26.87** | **27.46** | **27.40** | **27.77** | **28.71** | **0.6%** |
| Electricity related losses | 6.95 | 6.99 | 7.89 | 8.00 | 7.72 | 7.49 | 7.45 | 0.2% |
| **Total** | **30.93** | **31.03** | **34.76** | **35.46** | **35.11** | **35.26** | **36.16** | **0.5%** |

## Table A2. Energy consumption by sector and source (continued)
(quadrillion Btu per year, unless otherwise noted)

| Sector and source | Reference case | | | | | | | Annual growth 2011-2040 (percent) |
|---|---|---|---|---|---|---|---|---|
| | 2010 | 2011 | 2020 | 2025 | 2030 | 2035 | 2040 | |
| **Transportation** | | | | | | | | |
| Propane | 0.04 | 0.06 | 0.06 | 0.06 | 0.07 | 0.08 | 0.08 | 1.3% |
| E85[8] | 0.01 | 0.05 | 0.08 | 0.14 | 0.16 | 0.15 | 0.17 | 4.3% |
| Motor gasoline[2] | 16.79 | 16.31 | 14.88 | 13.86 | 13.06 | 12.69 | 12.64 | -0.9% |
| Jet fuel[9] | 3.07 | 3.01 | 3.11 | 3.20 | 3.28 | 3.35 | 3.42 | 0.4% |
| Distillate fuel oil[10] | 5.82 | 5.91 | 7.28 | 7.52 | 7.61 | 7.73 | 7.90 | 1.0% |
| Residual fuel oil | 0.88 | 0.82 | 0.84 | 0.85 | 0.86 | 0.86 | 0.87 | 0.2% |
| Other petroleum[11] | 0.17 | 0.17 | 0.15 | 0.15 | 0.16 | 0.16 | 0.16 | -0.1% |
| Liquid fuels and other petroleum subtotal | 26.78 | 26.32 | 26.42 | 25.79 | 25.20 | 25.01 | 25.24 | -0.1% |
| Pipeline fuel natural gas | 0.68 | 0.70 | 0.71 | 0.73 | 0.74 | 0.76 | 0.78 | 0.4% |
| Compressed / liquefied natural gas | 0.04 | 0.04 | 0.08 | 0.12 | 0.26 | 0.60 | 1.05 | 11.9% |
| Liquid hydrogen | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | - - |
| Electricity | 0.02 | 0.02 | 0.03 | 0.04 | 0.04 | 0.06 | 0.07 | 3.9% |
| **Delivered energy** | **27.52** | **27.09** | **27.24** | **26.68** | **26.25** | **26.43** | **27.14** | **0.0%** |
| Electricity related losses | 0.05 | 0.05 | 0.06 | 0.07 | 0.09 | 0.11 | 0.13 | 3.5% |
| **Total** | **27.57** | **27.13** | **27.30** | **26.75** | **26.33** | **26.54** | **27.27** | **0.0%** |
| **Delivered energy consumption for all sectors** | | | | | | | | |
| Liquefied petroleum gases | 2.83 | 2.82 | 3.21 | 3.29 | 3.23 | 3.16 | 3.08 | 0.3% |
| Propylene | 0.41 | 0.40 | 0.56 | 0.56 | 0.52 | 0.49 | 0.46 | 0.6% |
| E85[8] | 0.01 | 0.05 | 0.08 | 0.14 | 0.16 | 0.15 | 0.17 | 4.3% |
| Motor gasoline[2] | 17.13 | 16.64 | 15.26 | 14.24 | 13.43 | 13.07 | 13.03 | -0.8% |
| Jet fuel[9] | 3.07 | 3.01 | 3.11 | 3.20 | 3.28 | 3.35 | 3.42 | 0.4% |
| Kerosene | 0.04 | 0.03 | 0.03 | 0.03 | 0.02 | 0.02 | 0.02 | -0.3% |
| Distillate fuel oil | 8.00 | 8.12 | 9.35 | 9.49 | 9.51 | 9.58 | 9.74 | 0.6% |
| Residual fuel oil | 1.08 | 1.01 | 1.05 | 1.05 | 1.05 | 1.06 | 1.07 | 0.2% |
| Petrochemical feedstocks | 0.94 | 0.88 | 1.03 | 1.08 | 1.08 | 1.08 | 1.09 | 0.7% |
| Other petroleum[12] | 3.86 | 3.77 | 3.69 | 3.63 | 3.61 | 3.68 | 3.80 | 0.0% |
| Liquid fuels and other petroleum subtotal | 37.37 | 36.72 | 37.37 | 36.69 | 35.90 | 35.64 | 35.88 | -0.1% |
| Natural gas | 14.77 | 15.03 | 15.95 | 16.08 | 16.19 | 16.54 | 17.05 | 0.4% |
| Natural-gas-to-liquids heat and power | 0.00 | 0.00 | 0.13 | 0.16 | 0.21 | 0.27 | 0.33 | - - |
| Lease and plant fuel[6] | 1.31 | 1.42 | 1.57 | 1.68 | 1.73 | 1.84 | 1.97 | 1.1% |
| Pipeline natural gas | 0.68 | 0.70 | 0.71 | 0.73 | 0.74 | 0.76 | 0.78 | 0.4% |
| Natural gas subtotal | 16.77 | 17.15 | 18.36 | 18.66 | 18.87 | 19.42 | 20.13 | 0.6% |
| Metallurgical coal | 0.55 | 0.56 | 0.60 | 0.58 | 0.52 | 0.48 | 0.46 | -0.7% |
| Other coal | 1.12 | 1.10 | 1.06 | 1.06 | 1.06 | 1.07 | 1.11 | 0.0% |
| Coal-to-liquids heat and power | 0.00 | 0.00 | 0.00 | 0.07 | 0.09 | 0.12 | 0.15 | - - |
| Net coal coke imports | -0.01 | 0.01 | -0.01 | -0.03 | -0.04 | -0.06 | -0.05 | - - |
| Coal subtotal | 1.67 | 1.67 | 1.64 | 1.69 | 1.63 | 1.61 | 1.67 | -0.0% |
| Biofuels heat and coproducts | 0.85 | 0.67 | 0.82 | 0.82 | 0.85 | 0.97 | 1.37 | 2.5% |
| Renewable energy[13] | 2.01 | 2.08 | 2.28 | 2.42 | 2.54 | 2.68 | 2.86 | 1.1% |
| Liquid hydrogen | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | - - |
| Electricity | 12.81 | 12.71 | 13.54 | 14.13 | 14.59 | 15.08 | 15.72 | 0.7% |
| **Delivered energy** | **71.49** | **71.01** | **74.01** | **74.40** | **74.38** | **75.41** | **77.63** | **0.3%** |
| Electricity related losses | 26.86 | 26.69 | 27.03 | 27.94 | 28.43 | 29.00 | 30.00 | 0.4% |
| **Total** | **98.35** | **97.70** | **101.04** | **102.34** | **102.81** | **104.41** | **107.64** | **0.3%** |
| **Electric power[14]** | | | | | | | | |
| Distillate fuel oil | 0.08 | 0.06 | 0.08 | 0.08 | 0.08 | 0.08 | 0.08 | 0.9% |
| Residual fuel oil | 0.31 | 0.23 | 0.10 | 0.10 | 0.10 | 0.10 | 0.11 | -2.6% |
| Liquid fuels and other petroleum subtotal | 0.39 | 0.30 | 0.18 | 0.18 | 0.18 | 0.18 | 0.19 | -1.6% |
| Natural gas | 7.55 | 7.76 | 8.40 | 8.63 | 9.08 | 9.64 | 9.70 | 0.8% |
| Steam coal | 19.13 | 17.99 | 16.95 | 17.66 | 18.07 | 18.48 | 18.68 | 0.1% |
| Nuclear / uranium[15] | 8.43 | 8.26 | 9.25 | 9.54 | 9.49 | 9.14 | 9.44 | 0.5% |
| Renewable energy[16] | 3.85 | 4.74 | 5.49 | 5.77 | 5.93 | 6.38 | 7.44 | 1.6% |
| Electricity imports | 0.09 | 0.13 | 0.08 | 0.07 | 0.05 | 0.03 | 0.06 | -2.4% |
| **Total[17]** | **39.67** | **39.40** | **40.57** | **42.07** | **43.02** | **44.08** | **45.73** | **0.5%** |

## Table A2. Energy consumption by sector and source (continued)
(quadrillion Btu per year, unless otherwise noted)

| Sector and source | Reference case | | | | | | | Annual growth 2011-2040 (percent) |
|---|---|---|---|---|---|---|---|---|
| | 2010 | 2011 | 2020 | 2025 | 2030 | 2035 | 2040 | |
| **Total energy consumption** | | | | | | | | |
| Liquefied petroleum gases | 2.83 | 2.82 | 3.21 | 3.29 | 3.23 | 3.16 | 3.08 | 0.3% |
| Propylene | 0.41 | 0.40 | 0.56 | 0.56 | 0.52 | 0.49 | 0.46 | 0.6% |
| E85[8] | 0.01 | 0.05 | 0.08 | 0.14 | 0.16 | 0.15 | 0.17 | 4.3% |
| Motor gasoline[2] | 17.13 | 16.64 | 15.26 | 14.24 | 13.43 | 13.07 | 13.03 | -0.8% |
| Jet fuel[9] | 3.07 | 3.01 | 3.11 | 3.20 | 3.28 | 3.35 | 3.42 | 0.4% |
| Kerosene | 0.04 | 0.03 | 0.03 | 0.03 | 0.02 | 0.02 | 0.02 | -0.3% |
| Distillate fuel oil | 8.08 | 8.18 | 9.43 | 9.57 | 9.59 | 9.66 | 9.82 | 0.6% |
| Residual fuel oil | 1.38 | 1.24 | 1.15 | 1.15 | 1.15 | 1.16 | 1.17 | -0.2% |
| Petrochemical feedstocks | 0.94 | 0.88 | 1.03 | 1.08 | 1.08 | 1.08 | 1.09 | 0.7% |
| Other petroleum[12] | 3.86 | 3.77 | 3.69 | 3.63 | 3.61 | 3.68 | 3.80 | 0.0% |
| Liquid fuels and other petroleum subtotal | 37.76 | 37.02 | 37.54 | 36.87 | 36.08 | 35.82 | 36.07 | -0.1% |
| Natural gas | 22.32 | 22.79 | 24.36 | 24.71 | 25.27 | 26.18 | 26.75 | 0.6% |
| Natural-gas-to-liquids heat and power | 0.00 | 0.00 | 0.13 | 0.16 | 0.21 | 0.27 | 0.33 | - - |
| Lease and plant fuel[6] | 1.31 | 1.42 | 1.57 | 1.68 | 1.73 | 1.84 | 1.97 | 1.1% |
| Pipeline natural gas | 0.68 | 0.70 | 0.71 | 0.73 | 0.74 | 0.76 | 0.78 | 0.4% |
| Natural gas subtotal | 24.32 | 24.91 | 26.77 | 27.28 | 27.95 | 29.06 | 29.83 | 0.6% |
| Metallurgical coal | 0.55 | 0.56 | 0.60 | 0.58 | 0.52 | 0.48 | 0.46 | -0.7% |
| Other coal | 20.26 | 19.09 | 18.01 | 18.72 | 19.12 | 19.55 | 19.79 | 0.1% |
| Coal-to-liquids heat and power | 0.00 | 0.00 | 0.00 | 0.07 | 0.09 | 0.12 | 0.15 | - - |
| Net coal coke imports | -0.01 | 0.01 | -0.01 | -0.03 | -0.04 | -0.06 | -0.05 | - - |
| Coal subtotal | 20.81 | 19.66 | 18.59 | 19.35 | 19.70 | 20.09 | 20.35 | 0.1% |
| Nuclear / uranium[15] | 8.43 | 8.26 | 9.25 | 9.54 | 9.49 | 9.14 | 9.44 | 0.5% |
| Biofuels heat and coproducts | 0.85 | 0.67 | 0.82 | 0.82 | 0.85 | 0.97 | 1.37 | 2.5% |
| Renewable energy[18] | 5.86 | 6.82 | 7.77 | 8.18 | 8.47 | 9.07 | 10.30 | 1.4% |
| Liquid hydrogen | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | - - |
| Electricity imports | 0.09 | 0.13 | 0.08 | 0.07 | 0.05 | 0.03 | 0.06 | -2.4% |
| **Total** | **98.35** | **97.70** | **101.04** | **102.34** | **102.81** | **104.41** | **107.64** | **0.3%** |
| **Energy use and related statistics** | | | | | | | | |
| Delivered energy use | 71.49 | 71.01 | 74.01 | 74.40 | 74.38 | 75.41 | 77.63 | 0.3% |
| Total energy use | 98.35 | 97.70 | 101.04 | 102.34 | 102.81 | 104.41 | 107.64 | 0.3% |
| Ethanol consumed in motor gasoline and E85 | 1.11 | 1.17 | 1.34 | 1.29 | 1.24 | 1.20 | 1.21 | 0.1% |
| Population (millions) | 310.06 | 312.38 | 340.45 | 356.46 | 372.41 | 388.35 | 404.39 | 0.9% |
| Gross domestic product (billion 2005 dollars) | 13,063 | 13,299 | 16,859 | 18,985 | 21,355 | 24,095 | 27,277 | 2.5% |
| Carbon dioxide emissions (million metric tons) | 5,633.6 | 5,470.7 | 5,454.6 | 5,501.4 | 5,522.8 | 5,606.7 | 5,691.1 | 0.1% |

[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 water heating, and electricity generation from wind and solar photovoltaic sources.
[2]Includes ethanol (blends of 15 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 water heating and electricity generation from wind and solar photovoltaic sources.
[4]Includes energy for combined heat and power plants that have a non-regulatory status, and small on-site generating systems.
[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, in natural gas processing plant machinery, and for liquefaction in export facilities.
[7]Includes consumption of energy produced from hydroelectric, wood and wood waste, municipal waste, and other biomass sources. Excludes ethanol blends (15 percent or less) in motor gasoline.
[8]E85 refers to a blend of 85 percent ethanol (renewable) and 15 percent motor gasoline (nonrenewable). To address cold starting issues, the percentage of ethanol varies seasonally. The annual average ethanol content of 74 percent is used for this forecast.
[9]Includes only kerosene type.
[10]Diesel fuel for on- and off- road use.
[11]Includes aviation gasoline and lubricants.
[12]Includes unfinished oils, natural gasoline, motor gasoline blending components, aviation gasoline, lubricants, still gas, asphalt, road oil, petroleum coke, and miscellaneous petroleum products.
[13]Includes electricity generated for sale to the grid and for own use from renewable sources, and non-electric energy from renewable sources. Excludes ethanol and nonmarketed renewable energy consumption for geothermal heat pumps, buildings photovoltaic systems, and solar thermal water heaters.
[14]Includes consumption of energy by electricity-only and combined heat and power plants that have a regulatory status.
[15]These values represent the energy obtained from uranium when it is used in light water reactors. The total energy content of uranium is much larger, but alternative processes are required to take advantage of it.
[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 water heaters.
Btu = British thermal unit.
- - = Not applicable.
Note: Totals may not equal sum of components due to independent rounding. Data for 2010 and 2011 are model results and may differ slightly from official EIA data reports.
**Sources:** 2010 and 2011 consumption based on: U.S. Energy Information Administration (EIA), *Annual Energy Review 2011*, DOE/EIA-0384(2011) (Washington, DC, September 2012). 2010 and 2011 population and gross domestic product: IHS Global Insight Industry and Employment models, August 2012. 2010 and 2011 carbon dioxide emissions: EIA, *Annual Energy Review 2011*, DOE/EIA-0384(2011) (Washington, DC, September 2012). 2010 carbon dioxide emissions: EIA, *Monthly Energy Review*, DOE/EIA-0035(2011/10) (Washington, DC, October 2011). 2011 carbon dioxide emissions: EIA, *Monthly Energy Review*, DOE/EIA-0035(2012/08) (Washington, DC, August 2012). **Projections:** EIA, AEO2013 National Energy Modeling System run REF2013.D102312A.

## Table A3. Energy prices by sector and source
(2011 dollars per million Btu, unless otherwise noted)

| Sector and source | Reference case 2010 | 2011 | 2020 | 2025 | 2030 | 2035 | 2040 | Annual growth 2011-2040 (percent) |
|---|---|---|---|---|---|---|---|---|
| **Residential** | | | | | | | | |
| Propane | 27.61 | 25.06 | 23.41 | 24.77 | 25.73 | 26.70 | 27.99 | 0.4% |
| Distillate fuel oil | 21.77 | 26.38 | 26.91 | 29.08 | 31.26 | 33.71 | 36.54 | 1.1% |
| Natural gas | 11.36 | 10.80 | 11.78 | 12.67 | 13.37 | 14.60 | 16.36 | 1.4% |
| Electricity | 34.52 | 34.34 | 33.62 | 33.96 | 34.56 | 35.42 | 37.10 | 0.3% |
| **Commercial** | | | | | | | | |
| Propane | 24.10 | 22.10 | 20.04 | 21.74 | 22.97 | 24.23 | 25.94 | 0.6% |
| Distillate fuel oil | 21.35 | 25.87 | 24.26 | 26.51 | 28.51 | 30.91 | 33.74 | 0.9% |
| Residual fuel oil | 11.39 | 19.17 | 14.82 | 16.60 | 18.77 | 20.89 | 23.41 | 0.7% |
| Natural gas | 9.40 | 8.84 | 9.47 | 10.19 | 10.70 | 11.68 | 13.21 | 1.4% |
| Electricity | 30.49 | 29.98 | 28.57 | 28.49 | 28.65 | 29.66 | 31.75 | 0.2% |
| **Industrial**[1] | | | | | | | | |
| Propane | 23.73 | 22.54 | 20.51 | 22.33 | 23.64 | 24.97 | 26.78 | 0.6% |
| Distillate fuel oil | 21.87 | 26.50 | 24.67 | 27.02 | 28.91 | 31.31 | 34.16 | 0.9% |
| Residual fuel oil | 11.30 | 18.86 | 17.19 | 18.96 | 21.09 | 23.25 | 25.78 | 1.1% |
| Natural gas[2] | 5.48 | 4.89 | 5.53 | 6.15 | 6.56 | 7.45 | 8.88 | 2.1% |
| Metallurgical coal | 5.96 | 7.01 | 8.75 | 9.36 | 10.09 | 10.69 | 11.11 | 1.6% |
| Other industrial coal | 2.77 | 3.43 | 3.44 | 3.56 | 3.71 | 3.88 | 4.06 | 0.6% |
| Coal to liquids | - - | - - | - - | 2.30 | 2.55 | 2.76 | 2.95 | - - |
| Electricity | 20.26 | 19.98 | 18.72 | 19.18 | 19.73 | 20.80 | 22.74 | 0.4% |
| **Transportation** | | | | | | | | |
| Propane | 27.52 | 26.06 | 24.48 | 25.83 | 26.80 | 27.77 | 29.07 | 0.4% |
| E85[3] | 25.56 | 25.30 | 29.64 | 27.27 | 26.94 | 29.19 | 30.58 | 0.7% |
| Motor gasoline[4] | 23.18 | 28.70 | 27.84 | 29.26 | 30.73 | 32.99 | 36.18 | 0.8% |
| Jet fuel[5] | 16.57 | 22.49 | 21.50 | 23.73 | 26.03 | 28.52 | 31.07 | 1.1% |
| Diesel fuel (distillate fuel oil)[6] | 22.38 | 26.15 | 26.61 | 28.98 | 30.81 | 33.19 | 36.05 | 1.1% |
| Residual fuel oil | 10.62 | 17.83 | 14.91 | 16.58 | 18.34 | 20.25 | 22.45 | 0.8% |
| Natural gas[7] | 16.51 | 16.14 | 16.87 | 17.97 | 18.90 | 19.86 | 21.20 | 0.9% |
| Electricity | 33.91 | 32.77 | 29.60 | 30.40 | 31.53 | 32.84 | 35.07 | 0.2% |
| **Electric power**[8] | | | | | | | | |
| Distillate fuel oil | 19.22 | 23.30 | 22.45 | 24.61 | 26.80 | 29.23 | 32.03 | 1.1% |
| Residual fuel oil | 12.11 | 15.97 | 24.94 | 27.29 | 29.36 | 31.85 | 34.54 | 2.7% |
| Natural gas | 5.26 | 4.77 | 4.90 | 5.58 | 6.05 | 6.98 | 8.38 | 2.0% |
| Steam coal | 2.30 | 2.38 | 2.52 | 2.69 | 2.87 | 3.03 | 3.20 | 1.0% |
| **Average price to all users**[9] | | | | | | | | |
| Propane | 16.23 | 17.13 | 13.69 | 16.07 | 18.14 | 20.43 | 23.79 | 1.1% |
| E85[3] | 25.56 | 25.30 | 29.64 | 27.27 | 26.94 | 29.19 | 30.58 | 0.7% |
| Motor gasoline[4] | 23.06 | 28.47 | 27.84 | 29.26 | 30.72 | 32.99 | 36.17 | 0.8% |
| Jet fuel[5] | 16.57 | 22.49 | 21.50 | 23.73 | 26.03 | 28.52 | 31.07 | 1.1% |
| Distillate fuel oil | 22.17 | 26.18 | 26.25 | 28.62 | 30.48 | 32.88 | 35.73 | 1.1% |
| Residual fuel oil | 11.06 | 17.65 | 15.97 | 17.72 | 19.59 | 21.61 | 23.95 | 1.1% |
| Natural gas | 7.27 | 6.68 | 7.07 | 7.76 | 8.27 | 9.31 | 10.94 | 1.7% |
| Metallurgical coal | 5.96 | 7.01 | 8.75 | 9.36 | 10.09 | 10.69 | 11.11 | 1.6% |
| Other coal | 2.33 | 2.45 | 2.57 | 2.74 | 2.92 | 3.08 | 3.25 | 1.0% |
| Coal to liquids | - - | - - | - - | 2.30 | 2.55 | 2.76 | 2.95 | - - |
| Electricity | 29.40 | 29.03 | 27.50 | 27.79 | 28.41 | 29.55 | 31.58 | 0.3% |
| **Non-renewable energy expenditures by sector (billion 2011 dollars)** | | | | | | | | |
| Residential | 253.56 | 248.08 | 243.44 | 256.13 | 271.05 | 290.43 | 319.63 | 0.9% |
| Commercial | 182.47 | 179.97 | 181.68 | 192.15 | 203.80 | 221.86 | 249.60 | 1.1% |
| Industrial | 210.38 | 225.18 | 259.03 | 283.62 | 294.99 | 316.87 | 353.70 | 1.6% |
| Transportation | 584.31 | 718.25 | 694.73 | 722.24 | 749.40 | 808.74 | 900.68 | 0.8% |
| Total non-renewable expenditures | 1,230.73 | 1,371.48 | 1,378.87 | 1,454.13 | 1,519.24 | 1,637.91 | 1,823.61 | 1.0% |
| Transportation renewable expenditures | 0.16 | 1.24 | 2.44 | 3.92 | 4.39 | 4.43 | 5.05 | 5.0% |
| **Total expenditures** | **1,230.88** | **1,372.71** | **1,381.31** | **1,458.06** | **1,523.63** | **1,642.34** | **1,828.66** | **1.0%** |

**Table A3. Energy prices by sector and source (continued)**
(nominal dollars per million Btu, unless otherwise noted)

| Sector and source | Reference case | | | | | | | Annual growth 2011-2040 (percent) |
|---|---|---|---|---|---|---|---|---|
| | 2010 | 2011 | 2020 | 2025 | 2030 | 2035 | 2040 | |
| **Residential** | | | | | | | | |
| Propane | 27.04 | 25.06 | 27.00 | 31.21 | 35.51 | 40.35 | 46.20 | 2.1% |
| Distillate fuel oil | 21.31 | 26.38 | 31.03 | 36.64 | 43.14 | 50.93 | 60.31 | 2.9% |
| Natural gas | 11.12 | 10.80 | 13.58 | 15.97 | 18.45 | 22.06 | 27.01 | 3.2% |
| Electricity | 33.80 | 34.34 | 38.76 | 42.80 | 47.69 | 53.52 | 61.23 | 2.0% |
| **Commercial** | | | | | | | | |
| Propane | 23.60 | 22.10 | 23.11 | 27.39 | 31.70 | 36.62 | 42.82 | 2.3% |
| Distillate fuel oil | 20.91 | 25.87 | 27.97 | 33.41 | 39.34 | 46.71 | 55.68 | 2.7% |
| Residual fuel oil | 11.15 | 19.17 | 17.09 | 20.92 | 25.90 | 31.56 | 38.64 | 2.4% |
| Natural gas | 9.20 | 8.84 | 10.92 | 12.85 | 14.76 | 17.65 | 21.81 | 3.2% |
| Electricity | 29.86 | 29.98 | 32.94 | 35.90 | 39.54 | 44.82 | 52.40 | 1.9% |
| **Industrial**[1] | | | | | | | | |
| Propane | 23.23 | 22.54 | 23.65 | 28.14 | 32.62 | 37.74 | 44.20 | 2.3% |
| Distillate fuel oil | 21.42 | 26.50 | 28.45 | 34.05 | 39.89 | 47.31 | 56.39 | 2.6% |
| Residual fuel oil | 11.06 | 18.86 | 19.82 | 23.89 | 29.10 | 35.13 | 42.55 | 2.8% |
| Natural gas[2] | 5.37 | 4.89 | 6.38 | 7.75 | 9.05 | 11.25 | 14.66 | 3.9% |
| Metallurgical coal | 5.84 | 7.01 | 10.09 | 11.79 | 13.92 | 16.15 | 18.34 | 3.4% |
| Other industrial coal | 2.71 | 3.43 | 3.97 | 4.48 | 5.12 | 5.86 | 6.70 | 2.3% |
| Coal to liquids | - - | - - | - - | 2.90 | 3.52 | 4.17 | 4.87 | - - |
| Electricity | 19.84 | 19.98 | 21.59 | 24.17 | 27.22 | 31.42 | 37.54 | 2.2% |
| **Transportation** | | | | | | | | |
| Propane | 26.95 | 26.06 | 28.22 | 32.56 | 36.98 | 41.97 | 47.97 | 2.1% |
| E85[3] | 25.03 | 25.30 | 34.18 | 34.37 | 37.18 | 44.10 | 50.46 | 2.4% |
| Motor gasoline[4] | 22.70 | 28.70 | 32.10 | 36.88 | 42.41 | 49.85 | 59.72 | 2.6% |
| Jet fuel[5] | 16.22 | 22.49 | 24.79 | 29.90 | 35.92 | 43.09 | 51.27 | 2.9% |
| Diesel fuel (distillate fuel oil)[6] | 21.91 | 26.15 | 30.68 | 36.52 | 42.52 | 50.16 | 59.50 | 2.9% |
| Residual fuel oil | 10.40 | 17.83 | 17.19 | 20.89 | 25.31 | 30.60 | 37.06 | 2.6% |
| Natural gas[7] | 16.17 | 16.14 | 19.46 | 22.65 | 26.08 | 30.01 | 34.98 | 2.7% |
| Electricity | 33.20 | 32.77 | 34.13 | 38.31 | 43.51 | 49.63 | 57.88 | 2.0% |
| **Electric power**[8] | | | | | | | | |
| Distillate fuel oil | 18.82 | 23.30 | 25.89 | 31.02 | 36.98 | 44.17 | 52.87 | 2.9% |
| Residual fuel oil | 11.86 | 15.97 | 28.76 | 34.39 | 40.52 | 48.13 | 57.01 | 4.5% |
| Natural gas | 5.15 | 4.77 | 5.65 | 7.03 | 8.35 | 10.55 | 13.83 | 3.7% |
| Steam coal | 2.25 | 2.38 | 2.90 | 3.39 | 3.96 | 4.58 | 5.28 | 2.8% |

## Table A3. Energy prices by sector and source (continued)
(nominal dollars per million Btu, unless otherwise noted)

| Sector and source | Reference case | | | | | | | Annual growth 2011-2040 (percent) |
|---|---|---|---|---|---|---|---|---|
| | 2010 | 2011 | 2020 | 2025 | 2030 | 2035 | 2040 | |
| **Average price to all users[9]** | | | | | | | | |
| Propane | 15.89 | 17.13 | 15.78 | 20.26 | 25.03 | 30.86 | 39.26 | 2.9% |
| E85[3] | 25.03 | 25.30 | 34.18 | 34.37 | 37.18 | 44.10 | 50.46 | 2.4% |
| Motor gasoline[4] | 22.58 | 28.47 | 32.10 | 36.87 | 42.40 | 49.84 | 59.70 | 2.6% |
| Jet fuel[5] | 16.22 | 22.49 | 24.79 | 29.90 | 35.92 | 43.09 | 51.27 | 2.9% |
| Distillate fuel oil | 21.71 | 26.18 | 30.27 | 36.06 | 42.07 | 49.68 | 58.97 | 2.8% |
| Residual fuel oil | 10.83 | 17.65 | 18.41 | 22.33 | 27.03 | 32.66 | 39.53 | 2.8% |
| Natural gas | 7.12 | 6.68 | 8.16 | 9.78 | 11.41 | 14.06 | 18.06 | 3.5% |
| Metallurgical coal | 5.84 | 7.01 | 10.09 | 11.79 | 13.92 | 16.15 | 18.34 | 3.4% |
| Other coal | 2.28 | 2.45 | 2.97 | 3.46 | 4.03 | 4.65 | 5.37 | 2.7% |
| Coal to liquids | - - | - - | - - | 2.90 | 3.52 | 4.17 | 4.87 | - - |
| Electricity | 28.79 | 29.03 | 31.71 | 35.02 | 39.20 | 44.65 | 52.12 | 2.0% |
| **Non-renewable energy expenditures by sector (billion nominal dollars)** | | | | | | | | |
| Residential | 248.27 | 248.08 | 280.71 | 322.77 | 374.04 | 438.86 | 527.54 | 2.6% |
| Commercial | 178.66 | 179.97 | 209.48 | 242.14 | 281.23 | 335.25 | 411.95 | 2.9% |
| Industrial | 205.99 | 225.18 | 298.68 | 357.41 | 407.07 | 478.81 | 583.76 | 3.3% |
| Transportation | 572.11 | 718.25 | 801.07 | 910.16 | 1,034.13 | 1,222.05 | 1,486.52 | 2.5% |
| Total non-renewable expenditures | 1,205.03 | 1,371.48 | 1,589.94 | 1,832.48 | 2,096.47 | 2,474.97 | 3,009.77 | 2.7% |
| Transportation renewable expenditures | 0.15 | 1.24 | 2.81 | 4.95 | 6.06 | 6.70 | 8.33 | 6.8% |
| **Total expenditures** | **1,205.18** | **1,372.71** | **1,592.75** | **1,837.43** | **2,102.52** | **2,481.67** | **3,018.11** | **2.8%** |

[1]Includes energy for combined heat and power plants that have a non-regulatory status, and small on-site generating systems.
[2]Excludes use for lease and plant fuel.
[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]Kerosene-type jet fuel. Includes Federal and State taxes while excluding county and local taxes.
[6]Diesel fuel for on-road use. Includes Federal and State taxes while excluding county and local taxes.
[7]Natural gas used as a vehicle fuel. Includes estimated motor vehicle fuel taxes and estimated dispensing costs or charges.
[8]Includes electricity-only and combined heat and power plants that have a regulatory status.
[9]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 2010 and 2011 are model results and may differ slightly from official EIA data reports.
**Sources:** 2010 and 2011 prices for motor gasoline, distillate fuel oil, and jet fuel are based on prices in the U.S. Energy Information Administration (EIA), *Petroleum Marketing Monthly*, DOE/EIA-0380(2012/08) (Washington, DC, August 2012). 2010 residential, commercial, and industrial natural gas delivered prices: EIA, *Natural Gas Annual 2010*, DOE/EIA-0131(2010) (Washington, DC, December 2011). 2011 residential, commercial, and industrial natural gas delivered prices: EIA, *Natural Gas Monthly*, DOE/EIA-0130Natural Gas Monthly, DOE/EIA-0130(2012/07) (Washington, DC, July 2012). 2010 transportation sector natural gas delivered prices are based on: EIA, *Natural Gas Annual 2010*, DOE/EIA-0131(2010) (Washington, DC, December 2011) and estimated State taxes, Federal taxes, and dispensing costs or charges. 2011 transportation sector natural gas delivered prices are model results. 2010 and 2011 electric power sector distillate and residual fuel oil prices: EIA, *Monthly Energy Review*, DOE/EIA-0035(2012/09) (Washington, DC, September 2012). 2010 and 2011 electric power sector natural gas prices: EIA, *Electric Power Monthly*, DOE/EIA-0226, Electric Power Monthly, DOE/EIA-0226, April 2011 and April 2012, Table 4.2, and EIA, *State Energy Data Report 2010*, DOE/EIA-0214(2010) (Washington, DC, June 2012). 2010 and 2011 coal prices based on: EIA, *Quarterly Coal Report, October-December 2011*, DOE/EIA-0121(2011/4Q) (Washington, DC, March 2012) and EIA, AEO2013 National Energy Modeling System run REF2013.D102312A. 2010 and 2011 electricity prices: EIA, *Annual Energy Review 2011*, DOE/EIA-0384(2011) (Washington, DC, September 2012). 2010 and 2011 E85 prices derived from monthly prices in the Clean Cities Alternative Fuel Price Report. **Projections:** EIA, AEO2013 National Energy Modeling System run REF2013.D102312A.

## Table A4. Residential sector key indicators and consumption
(quadrillion Btu per year, unless otherwise noted)

| Key indicators and consumption | Reference case | | | | | | | Annual growth 2011-2040 (percent) |
|---|---|---|---|---|---|---|---|---|
| | 2010 | 2011 | 2020 | 2025 | 2030 | 2035 | 2040 | |
| **Key indicators** | | | | | | | | |
| **Households (millions)** | | | | | | | | |
| Single-family | 82.85 | 83.56 | 91.25 | 95.37 | 99.34 | 103.03 | 106.77 | 0.8% |
| Multifamily | 25.78 | 26.07 | 29.82 | 32.05 | 34.54 | 37.05 | 39.53 | 1.4% |
| Mobile homes | 6.60 | 6.54 | 6.45 | 6.60 | 6.75 | 6.88 | 7.02 | 0.2% |
| **Total** | **115.23** | **116.17** | **127.52** | **134.02** | **140.63** | **146.96** | **153.32** | **1.0%** |
| **Average house square footage** | **1,653** | **1,659** | **1,704** | **1,724** | **1,740** | **1,754** | **1,767** | **0.2%** |
| **Energy intensity** | | | | | | | | |
| **(million Btu per household)** | | | | | | | | |
| Delivered energy consumption | 99.2 | 97.2 | 86.0 | 82.5 | 79.7 | 77.3 | 75.5 | -0.9% |
| Total energy consumption | 189.0 | 185.0 | 161.7 | 157.4 | 154.0 | 151.4 | 150.6 | -0.7% |
| **(thousand Btu per square foot)** | | | | | | | | |
| Delivered energy consumption | 60.0 | 58.6 | 50.4 | 47.8 | 45.8 | 44.1 | 42.7 | -1.1% |
| Total energy consumption | 114.3 | 111.5 | 94.9 | 91.3 | 88.5 | 86.3 | 85.2 | -0.9% |
| **Delivered energy consumption by fuel** | | | | | | | | |
| **Electricity** | | | | | | | | |
| Space heating | 0.30 | 0.27 | 0.29 | 0.30 | 0.31 | 0.32 | 0.32 | 0.6% |
| Space cooling | 0.92 | 0.93 | 0.95 | 1.04 | 1.14 | 1.23 | 1.32 | 1.2% |
| Water heating | 0.45 | 0.45 | 0.50 | 0.52 | 0.53 | 0.54 | 0.55 | 0.7% |
| Refrigeration | 0.38 | 0.38 | 0.38 | 0.39 | 0.41 | 0.43 | 0.45 | 0.6% |
| Cooking | 0.11 | 0.11 | 0.12 | 0.13 | 0.14 | 0.15 | 0.16 | 1.3% |
| Clothes dryers | 0.20 | 0.20 | 0.22 | 0.23 | 0.24 | 0.25 | 0.26 | 1.0% |
| Freezers | 0.08 | 0.08 | 0.08 | 0.08 | 0.08 | 0.08 | 0.09 | 0.1% |
| Lighting | 0.65 | 0.63 | 0.45 | 0.40 | 0.38 | 0.37 | 0.38 | -1.8% |
| Clothes washers[1] | 0.03 | 0.03 | 0.03 | 0.02 | 0.02 | 0.02 | 0.03 | -0.8% |
| Dishwashers[1] | 0.10 | 0.10 | 0.10 | 0.10 | 0.11 | 0.12 | 0.13 | 0.8% |
| Televisions and related equipment[2] | 0.32 | 0.32 | 0.35 | 0.37 | 0.40 | 0.43 | 0.45 | 1.2% |
| Computers and related equipment[3] | 0.16 | 0.16 | 0.13 | 0.12 | 0.12 | 0.12 | 0.13 | -0.8% |
| Furnace fans and boiler circulation pumps | 0.13 | 0.13 | 0.14 | 0.14 | 0.14 | 0.14 | 0.14 | 0.2% |
| Other uses[4] | 1.11 | 1.07 | 1.08 | 1.21 | 1.33 | 1.46 | 1.62 | 1.4% |
| **Delivered energy** | **4.93** | **4.86** | **4.84** | **5.08** | **5.36** | **5.67** | **6.03** | **0.7%** |
| **Natural gas** | | | | | | | | |
| Space heating | 3.32 | 3.25 | 3.02 | 2.92 | 2.85 | 2.77 | 2.67 | -0.7% |
| Space cooling | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.1% |
| Water heating | 1.30 | 1.30 | 1.33 | 1.33 | 1.31 | 1.27 | 1.26 | -0.1% |
| Cooking | 0.22 | 0.22 | 0.22 | 0.22 | 0.23 | 0.23 | 0.24 | 0.3% |
| Clothes dryers | 0.06 | 0.06 | 0.06 | 0.06 | 0.07 | 0.07 | 0.07 | 0.7% |
| **Delivered energy** | **4.89** | **4.83** | **4.62** | **4.54** | **4.46** | **4.34** | **4.23** | **-0.5%** |
| **Distillate fuel oil** | | | | | | | | |
| Space heating | 0.49 | 0.50 | 0.45 | 0.40 | 0.36 | 0.32 | 0.29 | -1.9% |
| Water heating | 0.10 | 0.09 | 0.06 | 0.05 | 0.04 | 0.04 | 0.03 | -3.3% |
| **Delivered energy** | **0.58** | **0.59** | **0.51** | **0.45** | **0.40** | **0.36** | **0.32** | **-2.1%** |
| **Propane** | | | | | | | | |
| Space heating | 0.28 | 0.27 | 0.25 | 0.24 | 0.23 | 0.22 | 0.21 | -0.8% |
| Water heating | 0.07 | 0.07 | 0.05 | 0.05 | 0.05 | 0.04 | 0.04 | -1.8% |
| Cooking | 0.03 | 0.03 | 0.03 | 0.03 | 0.03 | 0.03 | 0.02 | -0.7% |
| Other uses[5] | 0.15 | 0.16 | 0.19 | 0.21 | 0.22 | 0.23 | 0.25 | 1.5% |
| **Delivered energy** | **0.53** | **0.53** | **0.52** | **0.52** | **0.52** | **0.52** | **0.52** | **-0.0%** |
| Marketed renewables (wood)[6] | 0.44 | 0.45 | 0.44 | 0.44 | 0.45 | 0.45 | 0.45 | 0.1% |
| Other fuels[7] | 0.04 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | -1.5% |

## Table A4. Residential sector key indicators and consumption (continued)
(quadrillion Btu per year, unless otherwise noted)

| Key indicators and consumption | Reference case | | | | | | | Annual growth 2011-2040 (percent) |
|---|---|---|---|---|---|---|---|---|
| | 2010 | 2011 | 2020 | 2025 | 2030 | 2035 | 2040 | |
| **Delivered energy consumption by end use** | | | | | | | | |
| Space heating | 4.86 | 4.76 | 4.47 | 4.32 | 4.22 | 4.09 | 3.96 | -0.6% |
| Space cooling | 0.92 | 0.93 | 0.95 | 1.04 | 1.14 | 1.23 | 1.32 | 1.2% |
| Water heating | 1.91 | 1.91 | 1.94 | 1.95 | 1.93 | 1.89 | 1.89 | -0.0% |
| Refrigeration | 0.38 | 0.38 | 0.38 | 0.39 | 0.41 | 0.43 | 0.45 | 0.6% |
| Cooking | 0.36 | 0.36 | 0.37 | 0.38 | 0.40 | 0.41 | 0.42 | 0.6% |
| Clothes dryers | 0.25 | 0.25 | 0.28 | 0.29 | 0.30 | 0.32 | 0.33 | 0.9% |
| Freezers | 0.08 | 0.08 | 0.08 | 0.08 | 0.08 | 0.08 | 0.09 | 0.1% |
| Lighting | 0.65 | 0.63 | 0.45 | 0.40 | 0.38 | 0.37 | 0.38 | -1.8% |
| Clothes washers[1] | 0.03 | 0.03 | 0.03 | 0.02 | 0.02 | 0.02 | 0.03 | -0.8% |
| Dishwashers[1] | 0.10 | 0.10 | 0.10 | 0.10 | 0.11 | 0.12 | 0.13 | 0.8% |
| Televisions and related equipment[2] | 0.32 | 0.32 | 0.35 | 0.37 | 0.40 | 0.43 | 0.45 | 1.2% |
| Computers and related equipment[3] | 0.16 | 0.16 | 0.13 | 0.12 | 0.12 | 0.12 | 0.13 | -0.8% |
| Furnace fans and boiler circulation pumps | 0.13 | 0.13 | 0.14 | 0.14 | 0.14 | 0.14 | 0.14 | 0.2% |
| Other uses[8] | 1.26 | 1.23 | 1.28 | 1.41 | 1.55 | 1.69 | 1.87 | 1.5% |
| **Delivered energy** | **11.41** | **11.28** | **10.95** | **11.04** | **11.20** | **11.35** | **11.57** | **0.1%** |
| **Electricity related losses** | **10.35** | **10.20** | **9.66** | **10.04** | **10.45** | **10.90** | **11.50** | **0.4%** |
| **Total energy consumption by end use** | | | | | | | | |
| Space heating | 5.49 | 5.33 | 5.05 | 4.93 | 4.83 | 4.71 | 4.57 | -0.5% |
| Space cooling | 2.84 | 2.88 | 2.86 | 3.10 | 3.35 | 3.60 | 3.84 | 1.0% |
| Water heating | 2.85 | 2.85 | 2.95 | 2.99 | 2.97 | 2.92 | 2.94 | 0.1% |
| Refrigeration | 1.16 | 1.16 | 1.14 | 1.16 | 1.21 | 1.25 | 1.31 | 0.4% |
| Cooking | 0.58 | 0.59 | 0.62 | 0.65 | 0.67 | 0.70 | 0.72 | 0.7% |
| Clothes dryers | 0.66 | 0.66 | 0.71 | 0.74 | 0.77 | 0.80 | 0.83 | 0.8% |
| Freezers | 0.25 | 0.26 | 0.25 | 0.25 | 0.25 | 0.24 | 0.25 | -0.1% |
| Lighting | 2.02 | 1.97 | 1.35 | 1.19 | 1.11 | 1.09 | 1.10 | -2.0% |
| Clothes washers[1] | 0.10 | 0.10 | 0.08 | 0.07 | 0.07 | 0.07 | 0.07 | -1.0% |
| Dishwashers[1] | 0.32 | 0.32 | 0.31 | 0.31 | 0.33 | 0.35 | 0.37 | 0.5% |
| Televisions and related equipment[2] | 0.98 | 0.98 | 1.05 | 1.12 | 1.18 | 1.25 | 1.32 | 1.0% |
| Computers and related equipment[3] | 0.49 | 0.49 | 0.39 | 0.37 | 0.36 | 0.36 | 0.36 | -1.0% |
| Furnace fans and boiler circulation pumps | 0.42 | 0.42 | 0.42 | 0.42 | 0.42 | 0.42 | 0.41 | -0.0% |
| Other uses[8] | 3.60 | 3.48 | 3.44 | 3.80 | 4.14 | 4.49 | 4.97 | 1.2% |
| **Total** | **21.76** | **21.48** | **20.62** | **21.08** | **21.65** | **22.25** | **23.08** | **0.2%** |
| **Nonmarketed renewables[9]** | | | | | | | | |
| Geothermal heat pumps | 0.01 | 0.01 | 0.02 | 0.02 | 0.02 | 0.03 | 0.03 | 4.3% |
| Solar hot water heating | 0.01 | 0.01 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 1.6% |
| Solar photovoltaic | 0.01 | 0.02 | 0.14 | 0.15 | 0.17 | 0.18 | 0.21 | 9.1% |
| Wind | 0.00 | 0.00 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 7.0% |
| **Total** | **0.03** | **0.04** | **0.20** | **0.21** | **0.22** | **0.24** | **0.27** | **6.9%** |
| **Heating degree days[10]** | **4,388** | **4,240** | **4,054** | **3,978** | **3,903** | **3,829** | **3,756** | **-0.4%** |
| **Cooling degree days[10]** | **1,498** | **1,528** | **1,499** | **1,545** | **1,591** | **1,638** | **1,685** | **0.3%** |

[1]Does not include water heating portion of load.
[2]Includes televisions, set-top boxes, and video game consoles.
[3]Includes desktop and laptop computers, monitors, printers, speakers, networking equipment, and uninterruptible power supplies.
[4]Includes small electric devices, heating elements, and motors not listed above. Electric vehicles are included in the transportation sector.
[5]Includes such appliances as outdoor grills and mosquito traps.
[6]Includes wood used for primary and secondary heating in wood stoves or fireplaces as reported in the *Residential Energy Consumption Survey 2005*.
[7]Includes kerosene and coal.
[8]Includes all other uses listed above.
[9]Consumption determined by using the fossil fuel equivalent of 9,756 Btu per kilowatthour.
[10]See Table A5 for regional detail.
Btu = British thermal unit.
- - = Not applicable.
Note: Totals may not equal sum of components due to independent rounding. Data for 2010 and 2011 are model results and may differ slightly from official EIA data reports.
**Sources:** 2010 and 2011 consumption based on: U.S. Energy Information Administration (EIA), *Annual Energy Review 2011*, DOE/EIA-0384(2011) (Washington, DC, September 2012). 2010 and 2011 degree days based on state-level data from the National Oceanic and Atmospheric Administration's Climatic Data Center and Climate Prediction Center. **Projections:** EIA, AEO2013 National Energy Modeling System run REF2013.D102312A.

**Table A5. Commercial sector key indicators and consumption**
(quadrillion Btu per year, unless otherwise noted)

| Key indicators and consumption | Reference case | | | | | | | Annual growth 2011-2040 (percent) |
|---|---|---|---|---|---|---|---|---|
| | 2010 | 2011 | 2020 | 2025 | 2030 | 2035 | 2040 | |
| **Key indicators** | | | | | | | | |
| **Total floorspace (billion square feet)** | | | | | | | | |
| Surviving | 79.3 | 80.2 | 87.0 | 91.9 | 96.2 | 100.7 | 106.4 | 1.0% |
| New additions | 1.8 | 1.5 | 2.1 | 2.0 | 2.0 | 2.3 | 2.4 | 1.6% |
| **Total** | **81.1** | **81.7** | **89.1** | **93.9** | **98.1** | **103.0** | **108.8** | **1.0%** |
| **Energy consumption intensity (thousand Btu per square foot)** | | | | | | | | |
| Delivered energy consumption | 105.6 | 105.2 | 100.4 | 98.1 | 97.2 | 95.8 | 93.8 | -0.4% |
| Electricity related losses | 117.3 | 115.7 | 105.7 | 104.6 | 103.7 | 102.0 | 100.4 | -0.5% |
| Total energy consumption | 222.9 | 220.9 | 206.2 | 202.7 | 200.9 | 197.8 | 194.2 | -0.4% |
| **Delivered energy consumption by fuel** | | | | | | | | |
| **Purchased electricity** | | | | | | | | |
| Space heating[1] | 0.18 | 0.17 | 0.16 | 0.15 | 0.15 | 0.15 | 0.15 | -0.5% |
| Space cooling[1] | 0.56 | 0.57 | 0.53 | 0.54 | 0.56 | 0.58 | 0.59 | 0.1% |
| Water heating[1] | 0.09 | 0.09 | 0.09 | 0.09 | 0.09 | 0.08 | 0.08 | -0.4% |
| Ventilation | 0.49 | 0.49 | 0.54 | 0.56 | 0.58 | 0.59 | 0.60 | 0.6% |
| Cooking | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | -0.3% |
| Lighting | 0.96 | 0.94 | 0.89 | 0.90 | 0.90 | 0.88 | 0.87 | -0.3% |
| Refrigeration | 0.39 | 0.38 | 0.35 | 0.35 | 0.36 | 0.37 | 0.38 | 0.0% |
| Office equipment (PC) | 0.21 | 0.20 | 0.19 | 0.20 | 0.20 | 0.21 | 0.22 | 0.2% |
| Office equipment (non-PC) | 0.23 | 0.22 | 0.25 | 0.27 | 0.28 | 0.30 | 0.31 | 1.1% |
| Other uses[2] | 1.42 | 1.41 | 1.70 | 1.88 | 2.08 | 2.29 | 2.51 | 2.0% |
| **Delivered energy** | **4.54** | **4.50** | **4.72** | **4.97** | **5.22** | **5.47** | **5.72** | **0.8%** |
| **Natural gas** | | | | | | | | |
| Space heating[1] | 1.65 | 1.64 | 1.66 | 1.62 | 1.58 | 1.53 | 1.45 | -0.4% |
| Space cooling[1] | 0.04 | 0.04 | 0.04 | 0.04 | 0.04 | 0.04 | 0.04 | -0.3% |
| Water heating[1] | 0.44 | 0.45 | 0.50 | 0.52 | 0.53 | 0.54 | 0.53 | 0.6% |
| Cooking | 0.18 | 0.18 | 0.20 | 0.21 | 0.22 | 0.22 | 0.23 | 0.7% |
| Other uses[3] | 0.86 | 0.91 | 1.00 | 1.05 | 1.13 | 1.26 | 1.43 | 1.6% |
| **Delivered energy** | **3.17** | **3.23** | **3.40** | **3.43** | **3.50** | **3.59** | **3.68** | **0.4%** |
| **Distillate fuel oil** | | | | | | | | |
| Space heating[1] | 0.14 | 0.13 | 0.11 | 0.10 | 0.09 | 0.09 | 0.08 | -1.7% |
| Water heating[1] | 0.03 | 0.03 | 0.03 | 0.03 | 0.03 | 0.03 | 0.04 | 1.0% |
| Other uses[4] | 0.24 | 0.26 | 0.20 | 0.20 | 0.19 | 0.19 | 0.19 | -1.1% |
| **Delivered energy** | **0.41** | **0.42** | **0.34** | **0.33** | **0.32** | **0.31** | **0.30** | **-1.1%** |
| Marketed renewables (biomass) | 0.11 | 0.13 | 0.13 | 0.13 | 0.13 | 0.13 | 0.13 | 0.0% |
| Other fuels[5] | 0.34 | 0.32 | 0.36 | 0.37 | 0.37 | 0.37 | 0.38 | 0.6% |
| **Delivered energy consumption by end use** | | | | | | | | |
| Space heating[1] | 1.97 | 1.94 | 1.93 | 1.88 | 1.83 | 1.76 | 1.68 | -0.5% |
| Space cooling[1] | 0.60 | 0.61 | 0.57 | 0.58 | 0.59 | 0.61 | 0.63 | 0.1% |
| Water heating[1] | 0.56 | 0.57 | 0.62 | 0.64 | 0.65 | 0.66 | 0.65 | 0.5% |
| Ventilation | 0.49 | 0.49 | 0.54 | 0.56 | 0.58 | 0.59 | 0.60 | 0.6% |
| Cooking | 0.20 | 0.21 | 0.22 | 0.23 | 0.24 | 0.25 | 0.25 | 0.6% |
| Lighting | 0.96 | 0.94 | 0.89 | 0.90 | 0.90 | 0.88 | 0.87 | -0.3% |
| Refrigeration | 0.39 | 0.38 | 0.35 | 0.35 | 0.36 | 0.37 | 0.38 | 0.0% |
| Office equipment (PC) | 0.21 | 0.20 | 0.19 | 0.20 | 0.20 | 0.21 | 0.22 | 0.2% |
| Office equipment (non-PC) | 0.23 | 0.22 | 0.25 | 0.27 | 0.28 | 0.30 | 0.31 | 1.1% |
| Other uses[6] | 2.97 | 3.03 | 3.38 | 3.62 | 3.90 | 4.23 | 4.63 | 1.5% |
| **Delivered energy** | **8.57** | **8.60** | **8.95** | **9.22** | **9.54** | **9.86** | **10.21** | **0.6%** |

## Table A5. Commercial sector key indicators and consumption (continued)
(quadrillion Btu per year, unless otherwise noted)

| Key indicators and consumption | Reference case | | | | | | | Annual growth 2011-2040 (percent) |
|---|---|---|---|---|---|---|---|---|
| | 2010 | 2011 | 2020 | 2025 | 2030 | 2035 | 2040 | |
| **Electricity related losses** | **9.52** | **9.45** | **9.42** | **9.82** | **10.18** | **10.51** | **10.92** | **0.5%** |
| **Total energy consumption by end use** | | | | | | | | |
| Space heating[1] | 2.34 | 2.29 | 2.24 | 2.18 | 2.12 | 2.05 | 1.95 | -0.5% |
| Space cooling[1] | 1.77 | 1.81 | 1.62 | 1.65 | 1.68 | 1.72 | 1.77 | -0.1% |
| Water heating[1] | 0.75 | 0.76 | 0.80 | 0.81 | 0.82 | 0.82 | 0.81 | 0.2% |
| Ventilation | 1.52 | 1.53 | 1.62 | 1.66 | 1.70 | 1.72 | 1.73 | 0.4% |
| Cooking | 0.25 | 0.25 | 0.27 | 0.27 | 0.28 | 0.29 | 0.29 | 0.4% |
| Lighting | 2.97 | 2.91 | 2.68 | 2.68 | 2.66 | 2.58 | 2.52 | -0.5% |
| Refrigeration | 1.20 | 1.18 | 1.06 | 1.06 | 1.07 | 1.09 | 1.12 | -0.2% |
| Office equipment (PC) | 0.65 | 0.63 | 0.57 | 0.58 | 0.60 | 0.61 | 0.63 | -0.0% |
| Office equipment (non-PC) | 0.70 | 0.70 | 0.74 | 0.79 | 0.84 | 0.87 | 0.89 | 0.9% |
| Other uses[6] | 5.95 | 5.99 | 6.77 | 7.35 | 7.94 | 8.63 | 9.42 | 1.6% |
| **Total** | **18.09** | **18.05** | **18.37** | **19.04** | **19.72** | **20.37** | **21.13** | **0.5%** |
| **Nonmarketed renewable fuels[7]** | | | | | | | | |
| Solar thermal | 0.08 | 0.08 | 0.09 | 0.10 | 0.10 | 0.11 | 0.12 | 1.4% |
| Solar photovoltaic | 0.02 | 0.03 | 0.10 | 0.12 | 0.13 | 0.16 | 0.19 | 6.6% |
| Wind | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 0.01 | 7.7% |
| **Total** | **0.10** | **0.11** | **0.20** | **0.22** | **0.24** | **0.28** | **0.32** | **3.7%** |
| **Heating Degree Days** | | | | | | | | |
| New England | 5,944 | 6,138 | 6,131 | 6,062 | 5,992 | 5,922 | 5,850 | -0.2% |
| Middle Atlantic | 5,453 | 5,413 | 5,362 | 5,281 | 5,201 | 5,121 | 5,042 | -0.2% |
| East North Central | 6,209 | 6,187 | 6,073 | 6,019 | 5,965 | 5,911 | 5,856 | -0.2% |
| West North Central | 6,585 | 6,646 | 6,297 | 6,230 | 6,161 | 6,091 | 6,020 | -0.3% |
| South Atlantic | 3,183 | 2,555 | 2,660 | 2,627 | 2,596 | 2,566 | 2,538 | -0.0% |
| East South Central | 4,003 | 3,397 | 3,417 | 3,400 | 3,382 | 3,364 | 3,345 | -0.1% |
| West South Central | 2,503 | 2,203 | 2,036 | 1,996 | 1,956 | 1,916 | 1,876 | -0.6% |
| Mountain | 4,882 | 5,054 | 4,545 | 4,430 | 4,312 | 4,192 | 4,071 | -0.7% |
| Pacific | 3,202 | 3,411 | 3,094 | 3,076 | 3,057 | 3,039 | 3,022 | -0.4% |
| **United States** | **4,388** | **4,240** | **4,054** | **3,978** | **3,903** | **3,829** | **3,756** | **-0.4%** |
| **Cooling Degree Days** | | | | | | | | |
| New England | 655 | 607 | 588 | 611 | 635 | 659 | 683 | 0.4% |
| Middle Atlantic | 997 | 887 | 875 | 909 | 944 | 978 | 1,011 | 0.5% |
| East North Central | 978 | 898 | 805 | 815 | 824 | 834 | 844 | -0.2% |
| West North Central | 1,123 | 1,116 | 995 | 1,003 | 1,012 | 1,021 | 1,030 | -0.3% |
| South Atlantic | 2,289 | 2,357 | 2,228 | 2,271 | 2,313 | 2,356 | 2,397 | 0.1% |
| East South Central | 1,999 | 1,811 | 1,779 | 1,812 | 1,845 | 1,877 | 1,910 | 0.2% |
| West South Central | 2,755 | 3,194 | 2,847 | 2,911 | 2,974 | 3,037 | 3,099 | -0.1% |
| Mountain | 1,490 | 1,396 | 1,698 | 1,766 | 1,837 | 1,910 | 1,985 | 1.2% |
| Pacific | 746 | 809 | 913 | 925 | 938 | 950 | 961 | 0.6% |
| **United States** | **1,498** | **1,528** | **1,499** | **1,545** | **1,591** | **1,638** | **1,685** | **0.3%** |

[1]Includes fuel consumption for district services.
[2]Includes (but is not limited to) miscellaneous uses such as transformers, medical imaging and other medical equipment, elevators, escalators, off-road electric vehicles, laboratory fume hoods, laundry equipment, coffee brewers, and water services.
[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 (but is not limited to) miscellaneous uses such as transformers, medical imaging and other medical equipment, elevators, escalators, off-road electric vehicles, laboratory fume hoods, laundry equipment, coffee brewers, water services, 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, kerosene, and marketed renewable fuels (biomass).
[7]Consumption determined by using the fossil fuel equivalent of 9,756 Btu per kilowatthour.
Btu = British thermal unit.
PC = Personal computer.
Note: Totals may not equal sum of components due to independent rounding. Data for 2010 and 2011 are model results and may differ slightly from official EIA data reports.
**Sources:** 2010 and 2011 consumption based on: U.S. Energy Information Administration (EIA), *Annual Energy Review 2011*, DOE/EIA-0384(2011) (Washington, DC, September 2012). 2010 and 2011 degree days based on state-level data from the National Oceanic and Atmospheric Administration's Climatic Data Center and Climate Prediction Center. **Projections:** EIA, AEO2013 National Energy Modeling System run REF2013.D102312A.

## Table A6. Industrial sector key indicators and consumption

| Key indicators and consumption | Reference case | | | | | | | Annual growth 2011-2040 (percent) |
|---|---|---|---|---|---|---|---|---|
| | 2010 | 2011 | 2020 | 2025 | 2030 | 2035 | 2040 | |
| **Key indicators** | | | | | | | | |
| **Value of shipments (billion 2005 dollars)** | | | | | | | | |
| Manufacturing | 4,257 | 4,438 | 5,683 | 6,253 | 6,712 | 7,285 | 7,972 | 2.0% |
| Nonmanufacturing | 1,585 | 1,582 | 2,211 | 2,295 | 2,375 | 2,494 | 2,644 | 1.8% |
| **Total** | **5,842** | **6,019** | **7,894** | **8,548** | **9,087** | **9,779** | **10,616** | **2.0%** |
| **Energy prices** | | | | | | | | |
| (2011 dollars per million Btu) | | | | | | | | |
| Liquefied petroleum gases | 23.73 | 22.54 | 20.51 | 22.33 | 23.64 | 24.97 | 26.78 | 0.6% |
| Motor gasoline | 17.16 | 17.14 | 27.71 | 29.11 | 30.56 | 32.80 | 35.98 | 2.6% |
| Distillate fuel oil | 21.87 | 26.50 | 24.67 | 27.02 | 28.91 | 31.31 | 34.16 | 0.9% |
| Residual fuel oil | 11.30 | 18.86 | 17.19 | 18.96 | 21.09 | 23.25 | 25.78 | 1.1% |
| Asphalt and road oil | 5.74 | 9.66 | 11.94 | 13.28 | 14.64 | 16.19 | 18.05 | 2.2% |
| Natural gas heat and power | 5.18 | 4.54 | 5.19 | 5.84 | 6.28 | 7.18 | 8.64 | 2.2% |
| Natural gas feedstocks | 5.81 | 5.28 | 5.87 | 6.47 | 6.86 | 7.73 | 9.15 | 1.9% |
| Metallurgical coal | 5.96 | 7.01 | 8.75 | 9.36 | 10.09 | 10.69 | 11.11 | 1.6% |
| Other industrial coal | 2.77 | 3.43 | 3.44 | 3.56 | 3.71 | 3.88 | 4.06 | 0.6% |
| Coal to liquids | - - | - - | - - | 2.30 | 2.55 | 2.76 | 2.95 | - - |
| Electricity | 20.26 | 19.98 | 18.72 | 19.18 | 19.73 | 20.80 | 22.74 | 0.4% |
| (nominal dollars per million Btu) | | | | | | | | |
| Liquefied petroleum gases | 23.23 | 22.54 | 23.65 | 28.14 | 32.62 | 37.74 | 44.20 | 2.3% |
| Motor gasoline | 16.80 | 17.14 | 31.95 | 36.69 | 42.17 | 49.57 | 59.39 | 4.4% |
| Distillate fuel oil | 21.42 | 26.50 | 28.45 | 34.05 | 39.89 | 47.31 | 56.39 | 2.6% |
| Residual fuel oil | 11.06 | 18.86 | 19.82 | 23.89 | 29.10 | 35.13 | 42.55 | 2.8% |
| Asphalt and road oil | 5.62 | 9.66 | 13.77 | 16.73 | 20.20 | 24.46 | 29.78 | 4.0% |
| Natural gas heat and power | 5.07 | 4.54 | 5.99 | 7.36 | 8.66 | 10.85 | 14.25 | 4.0% |
| Natural gas feedstocks | 5.69 | 5.28 | 6.77 | 8.15 | 9.46 | 11.68 | 15.10 | 3.7% |
| Metallurgical coal | 5.84 | 7.01 | 10.09 | 11.79 | 13.92 | 16.15 | 18.34 | 3.4% |
| Other industrial coal | 2.71 | 3.43 | 3.97 | 4.48 | 5.12 | 5.86 | 6.70 | 2.3% |
| Coal to liquids | - - | - - | - - | 2.90 | 3.52 | 4.17 | 4.87 | - - |
| Electricity | 19.84 | 19.98 | 21.59 | 24.17 | 27.22 | 31.42 | 37.54 | 2.2% |
| **Energy consumption (quadrillion Btu)[1]** | | | | | | | | |
| **Industrial consumption excluding refining** | | | | | | | | |
| Liquefied petroleum gases heat and power | 0.09 | 0.07 | 0.06 | 0.06 | 0.06 | 0.06 | 0.07 | -0.2% |
| Liquefied petroleum gases feedstocks | 2.02 | 2.02 | 2.40 | 2.48 | 2.41 | 2.34 | 2.24 | 0.4% |
| Propylene | 0.41 | 0.40 | 0.56 | 0.56 | 0.52 | 0.49 | 0.46 | 0.6% |
| Motor gasoline | 0.28 | 0.27 | 0.32 | 0.32 | 0.32 | 0.32 | 0.32 | 0.6% |
| Distillate fuel oil | 1.19 | 1.20 | 1.22 | 1.19 | 1.18 | 1.19 | 1.22 | 0.0% |
| Residual fuel oil | 0.12 | 0.11 | 0.11 | 0.11 | 0.11 | 0.11 | 0.11 | 0.0% |
| Petrochemical feedstocks | 0.94 | 0.88 | 1.03 | 1.08 | 1.08 | 1.08 | 1.09 | 0.7% |
| Petroleum coke | 0.16 | 0.15 | 0.33 | 0.35 | 0.34 | 0.34 | 0.34 | 3.0% |
| Asphalt and road oil | 0.88 | 0.86 | 1.11 | 1.13 | 1.16 | 1.21 | 1.30 | 1.4% |
| Miscellaneous petroleum[2] | 0.71 | 0.67 | 0.43 | 0.41 | 0.37 | 0.36 | 0.37 | -2.0% |
| Petroleum subtotal | 6.80 | 6.62 | 7.57 | 7.69 | 7.55 | 7.50 | 7.52 | 0.4% |
| Natural gas heat and power | 4.81 | 5.03 | 5.74 | 5.84 | 5.84 | 5.93 | 6.04 | 0.6% |
| Natural gas feedstocks | 0.48 | 0.46 | 0.55 | 0.55 | 0.51 | 0.48 | 0.45 | -0.1% |
| Lease and plant fuel[3] | 1.31 | 1.42 | 1.57 | 1.68 | 1.73 | 1.84 | 1.97 | 1.1% |
| Natural gas subtotal | 6.60 | 6.91 | 7.86 | 8.07 | 8.09 | 8.25 | 8.45 | 0.7% |
| Metallurgical coal and coke[4] | 0.55 | 0.57 | 0.59 | 0.55 | 0.48 | 0.42 | 0.41 | -1.1% |
| Other industrial coal | 1.00 | 1.04 | 1.00 | 1.00 | 1.00 | 1.02 | 1.05 | 0.0% |
| Coal subtotal | 1.54 | 1.62 | 1.58 | 1.56 | 1.48 | 1.44 | 1.46 | -0.3% |
| Renewables[5] | 1.47 | 1.51 | 1.72 | 1.85 | 1.97 | 2.11 | 2.28 | 1.4% |
| Purchased electricity | 3.10 | 3.12 | 3.74 | 3.84 | 3.75 | 3.68 | 3.68 | 0.6% |
| **Delivered energy** | **19.52** | **19.78** | **22.47** | **23.00** | **22.83** | **22.97** | **23.39** | **0.6%** |
| Electricity related losses | 6.51 | 6.55 | 7.46 | 7.59 | 7.30 | 7.07 | 7.02 | 0.2% |
| **Total** | **26.03** | **26.33** | **29.93** | **30.59** | **30.14** | **30.05** | **30.41** | **0.5%** |

## Table A6. Industrial sector key indicators and consumption (continued)

| Key indicators and consumption | Reference case | | | | | | | Annual growth 2011-2040 (percent) |
|---|---|---|---|---|---|---|---|---|
| | 2010 | 2011 | 2020 | 2025 | 2030 | 2035 | 2040 | |
| **Refining consumption** | | | | | | | | |
| Liquefied petroleum gases heat and power | 0.01 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | - - |
| Distillate fuel oil | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | - - |
| Residual fuel oil | 0.01 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | - - |
| Petroleum coke | 0.52 | 0.53 | 0.42 | 0.40 | 0.40 | 0.40 | 0.41 | -0.9% |
| Still gas | 1.41 | 1.40 | 1.25 | 1.19 | 1.19 | 1.21 | 1.23 | -0.4% |
| Miscellaneous petroleum[2] | 0.01 | 0.01 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | -22.9% |
| Petroleum subtotal | 1.96 | 1.95 | 1.67 | 1.59 | 1.59 | 1.61 | 1.64 | -0.6% |
| Natural gas heat and power | 1.38 | 1.43 | 1.57 | 1.60 | 1.62 | 1.61 | 1.60 | 0.4% |
| Natural-gas-to-liquids heat and power | 0.00 | 0.00 | 0.13 | 0.16 | 0.21 | 0.27 | 0.33 | - - |
| Natural gas subtotal | 1.38 | 1.43 | 1.70 | 1.77 | 1.83 | 1.88 | 1.93 | 1.0% |
| Other industrial coal | 0.06 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | - - |
| Coal-to-liquids heat and power | 0.00 | 0.00 | 0.00 | 0.07 | 0.09 | 0.12 | 0.15 | - - |
| Coal subtotal | 0.06 | 0.00 | 0.00 | 0.07 | 0.09 | 0.12 | 0.15 | - - |
| Biofuels heat and coproducts | 0.85 | 0.67 | 0.82 | 0.82 | 0.85 | 0.97 | 1.37 | 2.5% |
| Purchased electricity | 0.21 | 0.21 | 0.21 | 0.21 | 0.21 | 0.22 | 0.23 | 0.3% |
| **Delivered energy** | **4.46** | **4.26** | **4.40** | **4.46** | **4.57** | **4.80** | **5.31** | **0.8%** |
| Electricity related losses | 0.44 | 0.44 | 0.42 | 0.41 | 0.41 | 0.41 | 0.43 | -0.0% |
| **Total** | **4.90** | **4.70** | **4.82** | **4.87** | **4.98** | **5.21** | **5.75** | **0.7%** |
| **Total industrial sector consumption** | | | | | | | | |
| Liquefied petroleum gases heat and power | 0.10 | 0.08 | 0.06 | 0.06 | 0.06 | 0.06 | 0.07 | -0.5% |
| Liquefied petroleum gases feedstocks | 2.02 | 2.02 | 2.40 | 2.48 | 2.41 | 2.34 | 2.24 | 0.4% |
| Propylene | 0.41 | 0.40 | 0.56 | 0.56 | 0.52 | 0.49 | 0.46 | 0.6% |
| Motor gasoline | 0.28 | 0.27 | 0.32 | 0.32 | 0.32 | 0.32 | 0.32 | 0.6% |
| Distillate fuel oil | 1.19 | 1.21 | 1.22 | 1.19 | 1.18 | 1.19 | 1.22 | 0.0% |
| Residual fuel oil | 0.12 | 0.11 | 0.11 | 0.11 | 0.11 | 0.11 | 0.11 | -0.1% |
| Petrochemical feedstocks | 0.94 | 0.88 | 1.03 | 1.08 | 1.08 | 1.08 | 1.09 | 0.7% |
| Petroleum coke | 0.68 | 0.67 | 0.75 | 0.75 | 0.73 | 0.74 | 0.75 | 0.4% |
| Asphalt and road oil | 0.88 | 0.86 | 1.11 | 1.13 | 1.16 | 1.21 | 1.30 | 1.4% |
| Still gas | 1.41 | 1.40 | 1.25 | 1.19 | 1.19 | 1.21 | 1.23 | -0.4% |
| Miscellaneous petroleum[2] | 0.73 | 0.68 | 0.43 | 0.41 | 0.37 | 0.36 | 0.37 | -2.1% |
| Petroleum subtotal | 8.76 | 8.57 | 9.25 | 9.28 | 9.14 | 9.11 | 9.16 | 0.2% |
| Natural gas heat and power | 6.19 | 6.46 | 7.31 | 7.44 | 7.46 | 7.54 | 7.63 | 0.6% |
| Natural-gas-to-liquids heat and power | 0.00 | 0.00 | 0.13 | 0.16 | 0.21 | 0.27 | 0.33 | - - |
| Natural gas feedstocks | 0.48 | 0.46 | 0.55 | 0.55 | 0.51 | 0.48 | 0.45 | -0.1% |
| Lease and plant fuel[3] | 1.31 | 1.42 | 1.57 | 1.68 | 1.73 | 1.84 | 1.97 | 1.1% |
| Natural gas subtotal | 7.98 | 8.34 | 9.56 | 9.84 | 9.91 | 10.13 | 10.38 | 0.8% |
| Metallurgical coal and coke[4] | 0.55 | 0.57 | 0.59 | 0.55 | 0.48 | 0.42 | 0.41 | -1.1% |
| Other industrial coal | 1.06 | 1.04 | 1.00 | 1.00 | 1.00 | 1.02 | 1.05 | 0.0% |
| Coal-to-liquids heat and power | 0.00 | 0.00 | 0.00 | 0.07 | 0.09 | 0.12 | 0.15 | - - |
| Coal subtotal | 1.60 | 1.62 | 1.58 | 1.63 | 1.57 | 1.56 | 1.61 | -0.0% |
| Biofuels heat and coproducts | 0.85 | 0.67 | 0.82 | 0.82 | 0.85 | 0.97 | 1.37 | 2.5% |
| Renewables[5] | 1.47 | 1.51 | 1.72 | 1.85 | 1.97 | 2.11 | 2.28 | 1.4% |
| Purchased electricity | 3.31 | 3.33 | 3.95 | 4.05 | 3.96 | 3.90 | 3.91 | 0.6% |
| **Delivered energy** | **23.98** | **24.04** | **26.87** | **27.46** | **27.40** | **27.77** | **28.71** | **0.6%** |
| Electricity related losses | 6.95 | 6.99 | 7.89 | 8.00 | 7.72 | 7.49 | 7.45 | 0.2% |
| **Total** | **30.93** | **31.03** | **34.76** | **35.46** | **35.11** | **35.26** | **36.16** | **0.5%** |

# Table A6. Industrial sector key indicators and consumption (continued)

| Key indicators and consumption | Reference case | | | | | | | Annual growth 2011-2040 (percent) |
|---|---|---|---|---|---|---|---|---|
| | 2010 | 2011 | 2020 | 2025 | 2030 | 2035 | 2040 | |
| **Energy consumption per dollar of shipments (thousand Btu per 2005 dollar)** | | | | | | | | |
| Liquid fuels and other petroleum | 1.50 | 1.42 | 1.17 | 1.09 | 1.01 | 0.93 | 0.86 | -1.7% |
| Natural gas | 1.37 | 1.39 | 1.23 | 1.17 | 1.11 | 1.06 | 1.01 | -1.1% |
| Coal | 0.27 | 0.27 | 0.20 | 0.19 | 0.17 | 0.16 | 0.15 | -1.9% |
| Renewable fuels[5] | 0.40 | 0.36 | 0.32 | 0.31 | 0.31 | 0.32 | 0.34 | -0.2% |
| Purchased electricity | 0.57 | 0.55 | 0.50 | 0.47 | 0.44 | 0.40 | 0.37 | -1.4% |
| **Delivered energy** | **4.11** | **3.99** | **3.42** | **3.23** | **3.04** | **2.87** | **2.74** | **-1.3%** |
| **Industrial combined heat and power[1]** | | | | | | | | |
| Capacity (gigawatts) | 25.07 | 25.63 | 29.47 | 32.44 | 36.48 | 41.55 | 45.07 | 2.0% |
| Generation (billion kilowatthours) | 123.76 | 122.05 | 164.19 | 182.40 | 206.62 | 237.92 | 260.03 | 2.6% |

[1]Includes energy for combined heat and power plants that have a regulatory status, and small on-site generating systems.
[2]Includes lubricants and miscellaneous petroleum products.
[3]Represents natural gas used in well, field, and lease operations, in natural gas processing plant machinery, and for liquefaction in export facilities.
[4]Includes net coal coke imports.
[5]Includes consumption of energy produced from hydroelectric, wood and wood waste, municipal waste, and other biomass sources.
Btu = British thermal unit.
- - = Not applicable.
Note: Totals may not equal sum of components due to independent rounding. Data for 2010 and 2011 are model results and may differ slightly from official EIA data reports.
**Sources:** 2010 and 2011 prices for motor gasoline and distillate fuel oil are based on: U.S. Energy Information Administration (EIA), *Petroleum Marketing Monthly*, DOE/EIA-0380(2012/08) (Washington, DC, August 2012). 2010 and 2011 petrochemical feedstock and asphalt and road oil prices are based on: EIA, *State Energy Data Report 2010*, DOE/EIA-0214(2010) (Washington, DC, June 2012). 2010 and 2011 coal prices are based on: EIA, *Quarterly Coal Report, October-December 2011*, DOE/EIA-0121(2011/4Q) (Washington, DC, March 2012) and EIA, AEO2013 National Energy Modeling System run REF2013.D102312A. 2010 and 2011 electricity prices: EIA, *Annual Energy Review 2011*, DOE/EIA-0384(2011) (Washington, DC, September 2012). 2010 natural gas prices: EIA, *Natural Gas Annual 2010*, DOE/EIA-0131(2010) (Washington, DC, December 2011). 2011 natural gas prices: *Natural Gas Monthly*, DOE/EIA-0130Natural Gas Monthly, DOE/EIA-0130(2012/07) (Washington, DC, July 2012). 2010 refining consumption values are based on: *Petroleum Supply Annual 2010*, DOE/EIA-0340(2010)/1 (Washington, DC, July 2011). 2011 refining consumption based on: *Petroleum Supply Annual 2011*, DOE/EIA-0340(2011)/1 (Washington, DC, August 2012). Other 2010 and 2011 consumption values are based on: EIA, *Annual Energy Review 2011*, DOE/EIA-0384(2011) (Washington, DC, September 2012). 2010 and 2011 shipments: IHS Global Insight, Global Insight Industry model, August 2012. **Projections:** EIA, AEO2013 National Energy Modeling System run REF2013.D102312A.

# Table A7. Transportation sector key indicators and delivered energy consumption

| Key indicators and consumption | Reference case | | | | | | | Annual growth 2011-2040 (percent) |
|---|---|---|---|---|---|---|---|---|
| | 2010 | 2011 | 2020 | 2025 | 2030 | 2035 | 2040 | |
| **Key indicators** | | | | | | | | |
| **Travel indicators** | | | | | | | | |
| (billion vehicle miles traveled) | | | | | | | | |
| Light-duty vehicles less than 8,501 pounds | 2,654 | 2,629 | 2,870 | 3,089 | 3,323 | 3,532 | 3,719 | 1.2% |
| Commercial light trucks[1] | 65 | 65 | 80 | 87 | 94 | 102 | 110 | 1.8% |
| Freight trucks greater than 10,000 pounds | 235 | 240 | 323 | 350 | 371 | 401 | 438 | 2.1% |
| (billion seat miles available) | | | | | | | | |
| Air | 999 | 982 | 1,082 | 1,131 | 1,177 | 1,222 | 1,274 | 0.9% |
| (billion ton miles traveled) | | | | | | | | |
| Rail | 1,581 | 1,557 | 1,719 | 1,833 | 1,910 | 1,969 | 2,017 | 0.9% |
| Domestic shipping | 508 | 514 | 612 | 600 | 578 | 584 | 591 | 0.5% |
| **Energy efficiency indicators** | | | | | | | | |
| (miles per gallon) | | | | | | | | |
| New light-duty vehicle CAFE standard[2] | 25.5 | 27.6 | 37.0 | 46.8 | 47.2 | 47.5 | 47.8 | 1.9% |
| New car[2] | 27.7 | 30.9 | 43.9 | 54.6 | 54.6 | 54.7 | 54.7 | 2.0% |
| New light truck[2] | 23.4 | 24.6 | 30.9 | 39.5 | 39.5 | 39.5 | 39.5 | 1.6% |
| Compliance new light-duty vehicle[3] | 31.8 | 32.6 | 37.9 | 47.3 | 48.2 | 48.6 | 49.0 | 1.4% |
| New car[3] | 36.1 | 37.4 | 44.4 | 55.0 | 55.6 | 55.9 | 56.1 | 1.4% |
| New light truck[3] | 28.1 | 28.5 | 32.0 | 40.0 | 40.3 | 40.4 | 40.5 | 1.2% |
| Tested new light-duty vehicle[4] | 30.8 | 31.5 | 37.9 | 47.3 | 48.1 | 48.6 | 49.0 | 1.5% |
| New car[4] | 35.7 | 36.4 | 44.4 | 55.0 | 55.6 | 55.8 | 56.1 | 1.5% |
| New light truck[4] | 26.9 | 27.3 | 32.0 | 40.0 | 40.3 | 40.4 | 40.4 | 1.4% |
| On-road new light-duty vehicle[5] | 24.9 | 25.5 | 30.6 | 38.2 | 38.9 | 39.3 | 39.7 | 1.5% |
| New car[5] | 29.1 | 29.8 | 36.3 | 44.9 | 45.4 | 45.6 | 45.8 | 1.5% |
| New light truck[5] | 21.5 | 21.8 | 25.6 | 32.0 | 32.3 | 32.3 | 32.3 | 1.4% |
| Light-duty stock[6] | 20.9 | 20.6 | 24.1 | 27.6 | 31.3 | 34.2 | 36.1 | 2.0% |
| New commercial light truck[1] | 18.2 | 18.1 | 20.0 | 23.9 | 24.1 | 24.2 | 24.2 | 1.0% |
| Stock commercial light truck[1] | 14.6 | 14.9 | 17.9 | 20.1 | 22.2 | 23.5 | 24.1 | 1.7% |
| Freight truck | 6.7 | 6.7 | 7.3 | 7.7 | 8.0 | 8.1 | 8.2 | 0.7% |
| (seat miles per gallon) | | | | | | | | |
| Aircraft | 62.3 | 62.3 | 63.9 | 65.2 | 67.0 | 69.2 | 71.5 | 0.5% |
| (ton miles per thousand Btu) | | | | | | | | |
| Rail | 3.4 | 3.4 | 3.5 | 3.5 | 3.5 | 3.5 | 3.5 | 0.1% |
| Domestic shipping | 2.4 | 2.4 | 2.5 | 2.5 | 2.5 | 2.5 | 2.6 | 0.2% |
| **Energy use by mode (quadrillion Btu)** | | | | | | | | |
| Light-duty vehicles | 15.94 | 15.56 | 14.35 | 13.48 | 12.77 | 12.44 | 12.43 | -0.8% |
| Commercial light trucks[1] | 0.55 | 0.54 | 0.56 | 0.54 | 0.53 | 0.54 | 0.57 | 0.2% |
| Bus transportation | 0.25 | 0.25 | 0.27 | 0.28 | 0.29 | 0.31 | 0.32 | 0.9% |
| Freight trucks | 4.86 | 4.95 | 6.07 | 6.24 | 6.39 | 6.76 | 7.31 | 1.4% |
| Rail, passenger | 0.05 | 0.05 | 0.05 | 0.06 | 0.06 | 0.06 | 0.06 | 1.1% |
| Rail, freight | 0.46 | 0.45 | 0.49 | 0.53 | 0.54 | 0.56 | 0.57 | 0.8% |
| Shipping, domestic | 0.21 | 0.21 | 0.25 | 0.24 | 0.23 | 0.23 | 0.23 | 0.3% |
| Shipping, international | 0.85 | 0.80 | 0.81 | 0.82 | 0.82 | 0.83 | 0.84 | 0.2% |
| Recreational boats | 0.25 | 0.24 | 0.26 | 0.27 | 0.28 | 0.28 | 0.29 | 0.6% |
| Air | 2.52 | 2.46 | 2.65 | 2.73 | 2.78 | 2.82 | 2.86 | 0.5% |
| Military use | 0.76 | 0.74 | 0.63 | 0.65 | 0.68 | 0.72 | 0.77 | 0.1% |
| Lubricants | 0.14 | 0.13 | 0.12 | 0.12 | 0.12 | 0.13 | 0.13 | -0.1% |
| Pipeline fuel | 0.68 | 0.70 | 0.71 | 0.73 | 0.74 | 0.76 | 0.78 | 0.4% |
| **Total** | **27.52** | **27.09** | **27.24** | **26.68** | **26.24** | **26.43** | **27.14** | **0.0%** |

## Table A7. Transportation sector key indicators and delivered energy consumption (continued)

| Key indicators and consumption | Reference case | | | | | | | Annual growth 2011-2040 (percent) |
|---|---|---|---|---|---|---|---|---|
| | 2010 | 2011 | 2020 | 2025 | 2030 | 2035 | 2040 | |
| **Energy use by mode (million barrels per day oil equivalent)** | | | | | | | | |
| Light-duty vehicles | 8.37 | 8.46 | 7.85 | 7.38 | 6.99 | 6.80 | 6.80 | -0.7% |
| Commercial light trucks[1] | 0.28 | 0.28 | 0.29 | 0.28 | 0.27 | 0.28 | 0.29 | 0.2% |
| Bus transportation | 0.12 | 0.12 | 0.13 | 0.14 | 0.14 | 0.15 | 0.15 | 0.9% |
| Freight trucks | 2.34 | 2.39 | 2.92 | 3.01 | 3.08 | 3.25 | 3.52 | 1.3% |
| Rail, passenger | 0.02 | 0.02 | 0.02 | 0.03 | 0.03 | 0.03 | 0.03 | 1.1% |
| Rail, freight | 0.22 | 0.22 | 0.24 | 0.25 | 0.26 | 0.27 | 0.27 | 0.8% |
| Shipping, domestic | 0.10 | 0.10 | 0.12 | 0.11 | 0.11 | 0.11 | 0.11 | 0.3% |
| Shipping, international | 0.37 | 0.35 | 0.35 | 0.36 | 0.36 | 0.36 | 0.37 | 0.2% |
| Recreational boats | 0.13 | 0.13 | 0.14 | 0.15 | 0.15 | 0.15 | 0.16 | 0.6% |
| Air | 1.22 | 1.19 | 1.28 | 1.32 | 1.35 | 1.36 | 1.38 | 0.5% |
| Military use | 0.37 | 0.36 | 0.30 | 0.31 | 0.33 | 0.35 | 0.37 | 0.1% |
| Lubricants | 0.07 | 0.06 | 0.06 | 0.06 | 0.06 | 0.06 | 0.06 | -0.1% |
| Pipeline fuel | 0.32 | 0.33 | 0.34 | 0.34 | 0.35 | 0.36 | 0.37 | 0.4% |
| **Total** | **13.93** | **14.00** | **14.05** | **13.73** | **13.47** | **13.53** | **13.87** | **-0.0%** |

[1]Commercial trucks 8,501 to 10,000 pounds gross vehicle weight rating.
[2]CAFE standard based on projected new vehicle sales.
[3]Includes CAFE credits for alternative fueled vehicle sales and credit banking.
[4]Environmental Protection Agency rated miles per gallon.
[5]Tested new vehicle efficiency revised for on-road performance.
[6]Combined"on-the-road" estimate for all cars and light trucks.
CAFE = Corporate average fuel economy.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Data for 2010 and 2011 are model results and may differ slightly from official EIA data reports.
**Sources:** 2010 and 2011: U.S. Energy Information Administration (EIA), *Annual Energy Review 2011*, DOE/EIA-0384(2011) (Washington, DC, September 2012); Federal Highway Administration, *Highway Statistics 2010* (Washington, DC, February 2012); Oak Ridge National Laboratory, *Transportation Energy Data Book: Edition 31* (Oak Ridge, TN, July 2012); National Highway Traffic and Safety Administration, *Summary of Fuel Economy Performance* (Washington, DC, October 28, 2010); U.S. Department of Commerce, Bureau of the Census, "Vehicle Inventory and Use Survey," EC02TV (Washington, DC, December 2004); EIA, Alternatives to Traditional Transportation Fuels 2009 (Part II - User and Fuel Data), April 2011; EIA, *State Energy Data Report 2010*, DOE/EIA-0214(2010) (Washington, DC, June 2012); U.S. Department of Transportation, Research and Special Programs Administration, *Air Carrier Statistics Monthly, December 2010/2009* (Washington, DC, December 2010); and United States Department of Defense, Defense Fuel Supply Center, Factbook (January, 2010). **Projections:** EIA, AEO2013 National Energy Modeling System run REF2013.D102312A.

## Table A8. Electricity supply, disposition, prices, and emissions
(billion kilowatthours, unless otherwise noted)

| Supply, disposition, prices, and emissions | Reference case | | | | | | | Annual growth 2011-2040 (percent) |
|---|---|---|---|---|---|---|---|---|
| | 2010 | 2011 | 2020 | 2025 | 2030 | 2035 | 2040 | |
| **Generation by fuel type** | | | | | | | | |
| **Electric power sector[1]** | | | | | | | | |
| **Power only[2]** | | | | | | | | |
| Coal | 1,797 | 1,688 | 1,613 | 1,680 | 1,718 | 1,756 | 1,776 | 0.2% |
| Petroleum | 32 | 24 | 15 | 15 | 15 | 15 | 16 | -1.5% |
| Natural gas[3] | 779 | 809 | 948 | 996 | 1,093 | 1,193 | 1,224 | 1.4% |
| Nuclear power | 807 | 790 | 885 | 912 | 908 | 875 | 903 | 0.5% |
| Pumped storage/other[4] | 2 | 1 | 2 | 2 | 3 | 3 | 3 | 2.2% |
| Renewable sources[5] | 392 | 484 | 555 | 582 | 598 | 644 | 750 | 1.5% |
| Distributed generation (natural gas) | 0 | 0 | 3 | 6 | 10 | 12 | 13 | - - |
| **Total** | **3,809** | **3,797** | **4,021** | **4,194** | **4,345** | **4,497** | **4,684** | **0.7%** |
| **Combined heat and power[6]** | | | | | | | | |
| Coal | 31 | 27 | 27 | 27 | 27 | 28 | 28 | 0.2% |
| Petroleum | 2 | 2 | 1 | 1 | 1 | 1 | 1 | -4.1% |
| Natural gas | 123 | 121 | 130 | 131 | 128 | 127 | 125 | 0.1% |
| Renewable sources | 5 | 4 | 4 | 4 | 4 | 4 | 4 | -0.2% |
| **Total** | **163** | **157** | **161** | **162** | **161** | **160** | **158** | **0.0%** |
| **Total electric power sector generation** | **3,972** | **3,954** | **4,182** | **4,356** | **4,506** | **4,658** | **4,842** | **0.7%** |
| Less direct use | 17 | 12 | 13 | 13 | 13 | 13 | 13 | 0.0% |
| **Net available to the grid** | **3,956** | **3,942** | **4,169** | **4,343** | **4,493** | **4,645** | **4,830** | **0.7%** |
| **End-use sector[7]** | | | | | | | | |
| Coal | 20 | 15 | 16 | 20 | 21 | 23 | 25 | 1.7% |
| Petroleum | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 0.2% |
| Natural gas | 69 | 70 | 104 | 120 | 148 | 187 | 221 | 4.0% |
| Other gaseous fuels[8] | 10 | 11 | 14 | 14 | 14 | 14 | 14 | 0.9% |
| Renewable sources[9] | 32 | 36 | 68 | 75 | 82 | 92 | 104 | 3.7% |
| Other[10] | 4 | 4 | 4 | 4 | 4 | 4 | 4 | -0.3% |
| **Total end-use sector generation** | **138** | **139** | **208** | **235** | **271** | **322** | **370** | **3.4%** |
| Less direct use | 99 | 102 | 169 | 192 | 225 | 269 | 310 | 3.9% |
| **Total sales to the grid** | **39** | **37** | **39** | **43** | **47** | **53** | **60** | **1.7%** |
| **Total electricity generation by fuel** | | | | | | | | |
| Coal | 1847 | 1730 | 1656 | 1727 | 1766 | 1807 | 1829 | 0.2% |
| Petroleum | 37 | 28 | 17 | 18 | 18 | 18 | 18 | -1.5% |
| Natural gas | 970 | 1000 | 1184 | 1252 | 1379 | 1519 | 1582 | 1.6% |
| Nuclear power | 807 | 790 | 885 | 912 | 908 | 875 | 903 | 0.5% |
| Renewable sources[5,9] | 429 | 524 | 627 | 661 | 685 | 740 | 858 | 1.7% |
| Other[11] | 19 | 20 | 20 | 20 | 20 | 21 | 21 | 0.1% |
| **Total electricity generation** | **4110** | **4093** | **4389** | **4591** | **4777** | **4979** | **5212** | **0.8%** |
| **Net generation to the grid** | **3994** | **3979** | **4208** | **4386** | **4540** | **4698** | **4890** | **0.7%** |
| **Net imports** | **26** | **37** | **24** | **22** | **14** | **10** | **18** | **-2.4%** |
| **Electricity sales by sector** | | | | | | | | |
| Residential | 1446 | 1424 | 1419 | 1488 | 1572 | 1661 | 1767 | 0.7% |
| Commercial | 1330 | 1319 | 1384 | 1455 | 1531 | 1602 | 1677 | 0.8% |
| Industrial | 971 | 976 | 1158 | 1186 | 1161 | 1142 | 1145 | 0.6% |
| Transportation | 6 | 6 | 9 | 11 | 13 | 16 | 19 | 3.9% |
| **Total** | **3753** | **3725** | **3969** | **4140** | **4276** | **4421** | **4608** | **0.7%** |
| Direct use | 116 | 114 | 181 | 204 | 237 | 281 | 322 | 3.6% |
| **Total electricity use** | **3,870** | **3,841** | **4,151** | **4,344** | **4,513** | **4,702** | **4,930** | **0.9%** |

# Table A8. Electricity supply, disposition, prices, and emissions (continued)
(billion kilowatthours, unless otherwise noted)

| Supply, disposition, prices, and emissions | Reference case 2010 | 2011 | 2020 | 2025 | 2030 | 2035 | 2040 | Annual growth 2011-2040 (percent) |
|---|---|---|---|---|---|---|---|---|
| **End-use prices** | | | | | | | | |
| (2011 cents per kilowatthour) | | | | | | | | |
| Residential | 11.8 | 11.7 | 11.5 | 11.6 | 11.8 | 12.1 | 12.7 | 0.3% |
| Commercial | 10.4 | 10.2 | 9.7 | 9.7 | 9.8 | 10.1 | 10.8 | 0.2% |
| Industrial | 6.9 | 6.8 | 6.4 | 6.5 | 6.7 | 7.1 | 7.8 | 0.4% |
| Transportation | 11.6 | 11.2 | 10.1 | 10.4 | 10.8 | 11.2 | 12.0 | 0.2% |
| **All sectors average** | **10.0** | **9.9** | **9.4** | **9.5** | **9.7** | **10.1** | **10.8** | **0.3%** |
| (nominal cents per kilowatthour) | | | | | | | | |
| Residential | 11.5 | 11.7 | 13.2 | 14.6 | 16.3 | 18.3 | 20.9 | 2.0% |
| Commercial | 10.2 | 10.2 | 11.2 | 12.2 | 13.5 | 15.3 | 17.9 | 1.9% |
| Industrial | 6.8 | 6.8 | 7.4 | 8.2 | 9.3 | 10.7 | 12.8 | 2.2% |
| Transportation | 11.3 | 11.2 | 11.6 | 13.1 | 14.8 | 16.9 | 19.7 | 2.0% |
| **All sectors average** | **9.8** | **9.9** | **10.8** | **12.0** | **13.4** | **15.2** | **17.8** | **2.0%** |
| **Prices by service category** | | | | | | | | |
| (2011 cents per kilowatthour) | | | | | | | | |
| Generation | 6.0 | 5.8 | 5.6 | 5.8 | 6.0 | 6.4 | 7.1 | 0.7% |
| Transmission | 1.0 | 1.1 | 1.1 | 1.1 | 1.1 | 1.1 | 1.1 | 0.3% |
| Distribution | 3.0 | 3.1 | 2.8 | 2.6 | 2.6 | 2.6 | 2.6 | -0.5% |
| (nominal cents per kilowatthour) | | | | | | | | |
| Generation | 5.9 | 5.8 | 6.4 | 7.3 | 8.3 | 9.6 | 11.6 | 2.5% |
| Transmission | 1.0 | 1.1 | 1.2 | 1.4 | 1.5 | 1.7 | 1.9 | 2.0% |
| Distribution | 2.9 | 3.1 | 3.2 | 3.3 | 3.6 | 4.0 | 4.3 | 1.2% |
| **Electric power sector emissions**[1] | | | | | | | | |
| Sulfur dioxide (million short tons) | 5.00 | 4.42 | 1.35 | 1.43 | 1.50 | 1.60 | 1.66 | -3.3% |
| Nitrogen oxide (million short tons) | 2.07 | 1.94 | 1.72 | 1.80 | 1.82 | 1.85 | 1.87 | -0.1% |
| Mercury (short tons) | 33.14 | 31.49 | 6.84 | 7.19 | 7.33 | 7.55 | 7.75 | -4.7% |

[1]Includes electricity-only and combined heat and power plants that have a regulatory status.
[2]Includes plants that only produce electricity and have a regulatory status.
[3]Includes electricity generation from fuel cells.
[4]Includes non-biogenic municipal waste. The U.S. Energy Information Administration estimates that in 2011 approximately 6 billion kilowatthours of electricity were generated from a municipal waste stream containing petroleum-derived plastics and other non-renewable sources. See U.S. 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 or have a regulatory status).
[7]Includes combined heat and power plants and electricity-only plants in the commercial and industrial sectors that have a non-regulatory status; 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 2010 and 2011 are model results and may differ slightly from official EIA data reports.
**Sources:** 2010 and 2011 electric power sector generation; sales to the grid; net imports; electricity sales; and electricity end-use prices: U.S. Energy Information Administration (EIA), *Annual Energy Review 2011*, DOE/EIA-0384(2011) (Washington, DC, September 2012), and supporting databases. 2010 and 2011 emissions: U.S. Environmental Protection Agency, Clean Air Markets Database. 2010 and 2011 electricity prices by service category: EIA, AEO2013 National Energy Modeling System run REF2013.D102312A. **Projections**: EIA, AEO2013 National Energy Modeling System run REF2013.D102312A.

## Table A9. Electricity generating capacity
(gigawatts)

| Net summer capacity[1] | Reference case | | | | | | | Annual growth 2011-2040 (percent) |
|---|---|---|---|---|---|---|---|---|
| | 2010 | 2011 | 2020 | 2025 | 2030 | 2035 | 2040 | |
| **Electric power sector[2]** | | | | | | | | |
| **Power only[3]** | | | | | | | | |
| Coal | 308.0 | 309.5 | 268.7 | 267.9 | 267.9 | 267.9 | 269.0 | -0.5% |
| Oil and natural gas steam[4] | 105.6 | 101.9 | 86.4 | 78.3 | 69.1 | 66.6 | 64.0 | -1.6% |
| Combined cycle | 171.8 | 179.5 | 193.2 | 207.6 | 238.3 | 265.8 | 288.4 | 1.6% |
| Combustion turbine/diesel | 134.5 | 136.1 | 149.9 | 162.1 | 177.2 | 190.2 | 208.9 | 1.5% |
| Nuclear power[5] | 101.2 | 101.1 | 110.6 | 114.1 | 113.6 | 109.3 | 113.1 | 0.4% |
| Pumped storage | 22.3 | 22.3 | 22.3 | 22.3 | 22.3 | 22.3 | 22.3 | 0.0% |
| Fuel cells | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.8% |
| Renewable sources[6] | 125.3 | 132.3 | 152.9 | 155.6 | 159.7 | 174.3 | 206.8 | 1.6% |
| Distributed generation[7] | 0.0 | 0.0 | 0.9 | 1.9 | 3.1 | 4.1 | 5.1 | - - |
| **Total** | **968.7** | **982.8** | **985.0** | **1,009.8** | **1,051.2** | **1,100.7** | **1,177.7** | **0.6%** |
| **Combined heat and power[8]** | | | | | | | | |
| Coal | 4.9 | 4.9 | 4.3 | 4.2 | 4.2 | 4.2 | 4.2 | -0.5% |
| Oil and natural gas steam[4] | 0.8 | 0.8 | 0.8 | 0.8 | 0.8 | 0.8 | 0.8 | 0.0% |
| Combined cycle | 26.0 | 26.0 | 26.0 | 26.0 | 26.0 | 26.0 | 26.0 | 0.0% |
| Combustion turbine/diesel | 2.8 | 2.8 | 2.8 | 2.8 | 2.8 | 2.8 | 2.8 | -0.1% |
| Renewable sources[6] | 0.8 | 0.8 | 0.8 | 0.8 | 0.8 | 0.8 | 0.8 | 0.2% |
| **Total** | **35.3** | **35.3** | **34.6** | **34.6** | **34.6** | **34.6** | **34.6** | **-0.1%** |
| **Cumulative planned additions[9]** | | | | | | | | |
| Coal | 0.0 | 0.0 | 6.1 | 6.1 | 6.1 | 6.1 | 6.1 | - - |
| 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 | 10.9 | 10.9 | 10.9 | 10.9 | 10.9 | - - |
| Combustion turbine/diesel | 0.0 | 0.0 | 5.6 | 5.6 | 5.6 | 5.6 | 5.6 | - - |
| Nuclear power | 0.0 | 0.0 | 5.5 | 5.5 | 5.5 | 5.5 | 5.5 | - - |
| 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 | 18.1 | 18.1 | 18.1 | 18.1 | 18.1 | - - |
| Distributed generation[7] | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | - - |
| **Total** | **0.0** | **0.0** | **46.3** | **46.3** | **46.3** | **46.3** | **46.3** | **- -** |
| **Cumulative unplanned additions[9]** | | | | | | | | |
| Coal | 0.0 | 0.0 | 0.3 | 0.3 | 0.3 | 0.4 | 1.5 | - - |
| 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 | 3.1 | 17.4 | 48.2 | 75.7 | 98.3 | - - |
| Combustion turbine/diesel | 0.0 | 0.0 | 15.4 | 28.0 | 43.3 | 56.4 | 75.3 | - - |
| Nuclear power | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.8 | 5.5 | - - |
| 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 | 3.7 | 6.4 | 10.5 | 25.2 | 57.6 | - - |
| Distributed generation[7] | 0.0 | 0.0 | 0.9 | 1.9 | 3.1 | 4.1 | 5.1 | - - |
| **Total** | **0.0** | **0.0** | **23.4** | **54.1** | **105.4** | **162.4** | **243.3** | **- -** |
| **Cumulative electric power sector additions** | **0.0** | **0.0** | **69.7** | **100.4** | **151.7** | **208.7** | **289.5** | **- -** |
| **Cumulative retirements[10]** | | | | | | | | |
| Coal | 0.0 | 0.0 | 47.9 | 48.8 | 48.8 | 48.8 | 48.8 | - - |
| Oil and natural gas steam[4] | 0.0 | 0.0 | 15.5 | 23.6 | 32.8 | 35.3 | 37.9 | - - |
| Combined cycle | 0.0 | 0.0 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 | - - |
| Combustion turbine/diesel | 0.0 | 0.0 | 7.3 | 7.7 | 7.9 | 7.9 | 8.2 | - - |
| Nuclear power | 0.0 | 0.0 | 0.6 | 0.6 | 1.1 | 6.1 | 7.1 | - - |
| 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 | 1.2 | 1.2 | 1.2 | 1.2 | 1.2 | - - |
| **Total** | **0.0** | **0.0** | **72.7** | **82.1** | **92.0** | **99.6** | **103.4** | **- -** |
| **Total electric power sector capacity** | **1,004.1** | **1,018.1** | **1,019.6** | **1,044.4** | **1,085.8** | **1,135.3** | **1,212.3** | **0.6%** |

# Table A9. Electricity generating capacity (continued)
(gigawatts)

| Net summer capacity[1] | Reference case | | | | | | | Annual growth 2011-2040 (percent) |
|---|---|---|---|---|---|---|---|---|
| | 2010 | 2011 | 2020 | 2025 | 2030 | 2035 | 2040 | |
| **End-use generators[11]** | | | | | | | | |
| Coal | 3.6 | 3.6 | 3.6 | 4.2 | 4.4 | 4.6 | 4.9 | 1.1% |
| Petroleum | 0.7 | 0.7 | 1.0 | 1.0 | 1.0 | 1.0 | 1.0 | 1.0% |
| Natural gas | 15.1 | 15.0 | 17.2 | 19.7 | 24.1 | 30.1 | 35.1 | 3.0% |
| Other gaseous fuels[12] | 1.6 | 2.0 | 2.1 | 2.1 | 2.1 | 2.1 | 2.1 | 0.1% |
| Renewable sources[6] | 7.2 | 8.9 | 24.2 | 26.3 | 29.1 | 32.7 | 37.5 | 5.1% |
| Other[13] | 0.5 | 0.4 | 0.5 | 0.5 | 0.5 | 0.5 | 0.5 | 0.8% |
| **Total** | **28.7** | **30.6** | **48.5** | **53.7** | **61.1** | **71.0** | **81.0** | **3.4%** |
| **Cumulative capacity additions[9]** | **0.0** | **0.0** | **17.9** | **23.1** | **30.5** | **40.3** | **50.4** | **- -** |

[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 8.0 gigawatts of uprates through 2040.
[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, 2011.
[10]Cumulative retirements after December 31, 2011.
[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 refinery gas and still gas.
[13]Includes 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 2010 and 2011 are model results and may differ slightly from official EIA data reports.
**Sources:** 2010 and 2011 capacity and projected planned additions: U.S. Energy Information Administration (EIA), Form EIA-860, "Annual Electric Generator Report" (preliminary). **Projections:** EIA, AEO2013 National Energy Modeling System run REF2013.D102312A.

# Table A10. Electricity trade
(billion kilowatthours, unless otherwise noted)

| Electricity trade | Reference case | | | | | | | Annual growth 2011-2040 (percent) |
|---|---|---|---|---|---|---|---|---|
| | 2010 | 2011 | 2020 | 2025 | 2030 | 2035 | 2040 | |
| **Interregional electricity trade** | | | | | | | | |
| Gross domestic sales | | | | | | | | |
| Firm power | 237.5 | 173.8 | 104.4 | 47.1 | 24.2 | 24.2 | 24.2 | -6.6% |
| Economy | 150.1 | 158.1 | 162.7 | 167.5 | 189.9 | 186.3 | 220.2 | 1.1% |
| **Total** | **387.6** | **332.0** | **267.1** | **214.6** | **214.1** | **210.5** | **244.4** | **-1.1%** |
| Gross domestic sales (million 2011 dollars) | | | | | | | | |
| Firm power | 14,548.9 | 10,648.8 | 6,393.5 | 2,884.8 | 1,481.3 | 1,481.3 | 1,481.3 | -6.6% |
| Economy | 7,192.7 | 6,457.3 | 8,615.5 | 9,945.5 | 10,174.8 | 11,041.2 | 15,088.4 | 3.0% |
| **Total** | **21,741.6** | **17,106.2** | **15,008.9** | **12,830.3** | **11,656.1** | **12,522.5** | **16,569.7** | **-0.1%** |
| **International electricity trade** | | | | | | | | |
| Imports from Canada and Mexico | | | | | | | | |
| Firm power | 13.7 | 15.0 | 17.1 | 5.2 | 0.4 | 0.4 | 0.4 | -11.9% |
| Economy | 31.4 | 37.4 | 25.6 | 34.8 | 31.3 | 27.5 | 35.5 | -0.2% |
| **Total** | **45.1** | **52.4** | **42.7** | **40.0** | **31.7** | **27.8** | **35.8** | **-1.3%** |
| Exports to Canada and Mexico | | | | | | | | |
| Firm power | 3.7 | 2.6 | 1.3 | 0.4 | 0.0 | 0.0 | 0.0 | - - |
| Economy | 15.7 | 12.8 | 17.3 | 18.0 | 18.0 | 17.8 | 17.8 | 1.1% |
| **Total** | **19.4** | **15.4** | **18.6** | **18.4** | **18.0** | **17.8** | **17.8** | **0.5%** |

- - = Not applicable.
Note: Totals may not equal sum of components due to independent rounding. Data for 2010 and 2011 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:** 2010 and 2011 interregional firm electricity trade data: North American Electric Reliability Council (NERC), Electricity Sales and Demand Database 2007; NERC, 2011 Summer Reliability Assessment (May 2011); and NERC, Winter Reliability Assessment 2011/2012 (November 2011). 2010 and 2011 Mexican electricity trade data: U.S. Energy Information Administration (EIA), *Electric Power Annual 2010*, DOE/EIA-0348(2010) (Washington, DC, November 2011). 2010 Canadian international electricity trade data: National Energy Board, *Electricity Exports and Imports Statistics, 2010*. 2011 Canadian international electricity trade data: National Energy Board, *Electricity Exports and Imports Statistics, 2011*. **Projections:** EIA, AEO2013 National Energy Modeling System run REF2013.D102312A.

## Table A11. Liquid fuels supply and disposition
(million barrels per day, unless otherwise noted)

| Supply and disposition | Reference case | | | | | | | Annual growth 2011-2040 (percent) |
|---|---|---|---|---|---|---|---|---|
| | 2010 | 2011 | 2020 | 2025 | 2030 | 2035 | 2040 | |
| **Crude oil** | | | | | | | | |
| Domestic crude production[1] | 5.47 | 5.67 | 7.47 | 6.79 | 6.30 | 6.26 | 6.13 | 0.3% |
| Alaska | 0.60 | 0.57 | 0.49 | 0.35 | 0.38 | 0.35 | 0.41 | -1.1% |
| Lower 48 states | 4.88 | 5.10 | 6.98 | 6.44 | 5.92 | 5.91 | 5.72 | 0.4% |
| Net imports | 9.17 | 8.89 | 6.82 | 7.05 | 7.36 | 7.37 | 7.57 | -0.6% |
| Gross imports | 9.21 | 8.94 | 6.82 | 7.05 | 7.36 | 7.37 | 7.57 | -0.6% |
| Exports | 0.04 | 0.05 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | - - |
| Other crude supply[2] | 0.07 | 0.26 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | - - |
| **Total crude supply** | **14.72** | **14.81** | **14.29** | **13.84** | **13.66** | **13.63** | **13.70** | **-0.3%** |
| | | | | | | | | |
| **Other petroleum supply** | **3.41** | **3.02** | **4.04** | **4.12** | **3.82** | **3.57** | **3.29** | **0.3%** |
| Natural gas plant liquids | 2.07 | 2.22 | 3.13 | 3.17 | 2.90 | 2.91 | 2.92 | 1.0% |
| Net product imports | 0.29 | -0.30 | -0.13 | -0.04 | -0.08 | -0.37 | -0.67 | 2.7% |
| Gross refined product imports[3] | 1.23 | 1.15 | 1.47 | 1.50 | 1.53 | 1.50 | 1.42 | 0.7% |
| Unfinished oil imports | 0.61 | 0.69 | 0.56 | 0.53 | 0.51 | 0.48 | 0.45 | -1.5% |
| Blending component imports | 0.74 | 0.72 | 0.63 | 0.59 | 0.54 | 0.48 | 0.40 | -2.0% |
| Exports | 2.29 | 2.86 | 2.79 | 2.66 | 2.67 | 2.84 | 2.94 | 0.1% |
| Refinery processing gain[4] | 1.07 | 1.08 | 1.04 | 0.99 | 1.00 | 1.02 | 1.03 | -0.1% |
| Product stock withdrawal | -0.03 | 0.03 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | - - |
| **Other non-petroleum supply** | **1.03** | **1.09** | **1.51** | **1.55** | **1.58** | **1.68** | **1.97** | **2.1%** |
| Supply from renewable sources | 0.86 | 0.90 | 1.18 | 1.15 | 1.14 | 1.19 | 1.43 | 1.6% |
| Ethanol | 0.84 | 0.84 | 1.08 | 1.04 | 0.99 | 0.96 | 0.97 | 0.5% |
| Domestic production | 0.87 | 0.91 | 1.01 | 0.98 | 0.95 | 0.91 | 0.89 | -0.1% |
| Net imports | -0.02 | -0.07 | 0.07 | 0.06 | 0.04 | 0.05 | 0.08 | - - |
| Biodiesel | 0.02 | 0.06 | 0.08 | 0.08 | 0.08 | 0.08 | 0.08 | 1.0% |
| Domestic production | 0.02 | 0.06 | 0.07 | 0.07 | 0.07 | 0.07 | 0.07 | 0.4% |
| Net imports | -0.01 | -0.00 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | - - |
| Other biomass-derived liquids[5] | 0.00 | 0.00 | 0.02 | 0.03 | 0.06 | 0.14 | 0.38 | 21.6% |
| Liquids from gas | 0.00 | 0.00 | 0.08 | 0.10 | 0.13 | 0.16 | 0.20 | - - |
| Liquids from coal | 0.00 | 0.00 | 0.00 | 0.03 | 0.04 | 0.05 | 0.06 | - - |
| Other[6] | 0.17 | 0.18 | 0.25 | 0.26 | 0.28 | 0.28 | 0.28 | 1.5% |
| | | | | | | | | |
| **Total primary supply[7]** | **19.16** | **18.92** | **19.84** | **19.50** | **19.06** | **18.88** | **18.96** | **0.0%** |
| | | | | | | | | |
| **Liquid fuels consumption** | | | | | | | | |
| **by fuel** | | | | | | | | |
| Liquefied petroleum gases | 2.27 | 2.30 | 2.90 | 2.97 | 2.90 | 2.83 | 2.75 | 0.6% |
| E85[8] | 0.00 | 0.03 | 0.06 | 0.10 | 0.11 | 0.10 | 0.11 | 4.3% |
| Motor gasoline[9] | 8.99 | 8.74 | 8.34 | 7.78 | 7.34 | 7.14 | 7.12 | -0.7% |
| Jet fuel[10] | 1.43 | 1.42 | 1.52 | 1.56 | 1.60 | 1.63 | 1.66 | 0.5% |
| Distillate fuel oil[11] | 3.80 | 3.90 | 4.48 | 4.55 | 4.56 | 4.59 | 4.67 | 0.6% |
| Diesel | 3.32 | 3.51 | 4.04 | 4.14 | 4.18 | 4.23 | 4.33 | 0.7% |
| Residual fuel oil | 0.54 | 0.46 | 0.50 | 0.50 | 0.50 | 0.51 | 0.51 | 0.4% |
| Other[12] | 2.14 | 2.08 | 2.04 | 2.04 | 2.03 | 2.06 | 2.11 | 0.1% |
| **by sector** | | | | | | | | |
| Residential and commercial | 1.06 | 1.06 | 1.01 | 0.97 | 0.95 | 0.93 | 0.91 | -0.5% |
| Industrial[13] | 4.48 | 4.43 | 5.10 | 5.15 | 5.05 | 5.01 | 5.00 | 0.4% |
| Transportation | 13.57 | 13.63 | 13.65 | 13.29 | 12.95 | 12.84 | 12.95 | -0.2% |
| Electric power[14] | 0.17 | 0.13 | 0.08 | 0.08 | 0.08 | 0.08 | 0.08 | -1.5% |
| **Total** | **19.17** | **18.95** | **19.84** | **19.50** | **19.04** | **18.86** | **18.95** | **0.0%** |
| | | | | | | | | |
| **Discrepancy[15]** | **-0.01** | **-0.03** | **0.01** | **0.01** | **0.02** | **0.02** | **0.01** | **- -** |

## Table A11. Liquid fuels supply and disposition (continued)
(million barrels per day, unless otherwise noted)

| Supply and disposition | Reference case | | | | | | | Annual growth 2011-2040 (percent) |
|---|---|---|---|---|---|---|---|---|
| | 2010 | 2011 | 2020 | 2025 | 2030 | 2035 | 2040 | |
| Domestic refinery distillation capacity[16] | 17.6 | 17.7 | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 | -0.0% |
| Capacity utilization rate (percent)[17] | 86.0 | 86.0 | 90.7 | 87.8 | 86.7 | 86.5 | 86.9 | 0.0% |
| Net import share of product supplied (percent) | 49.3 | 45.0 | 34.1 | 36.3 | 38.5 | 37.4 | 36.9 | -0.7% |
| Net expenditures for imported crude oil and petroleum products (billion 2011 dollars) | 248.26 | 362.66 | 259.66 | 296.86 | 342.67 | 378.36 | 433.65 | 0.6% |

[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 on-site production of diesel and gasoline.
[6]Includes domestic sources of other blending components, other hydrocarbons, and ethers.
[7]Total crude supply plus other petroleum supply plus other non-petroleum supply.
[8]E85 refers to a blend of 85 percent ethanol (renewable) and 15 percent motor gasoline (nonrenewable). To address cold starting issues, the percentage of ethanol varies seasonally. The annual average ethanol content of 74 percent is used for this forecast.
[9]Includes ethanol and ethers blended into gasoline.
[10]Includes only kerosene type.
[11]Includes distillate 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 energy for combined heat and power plants that have a non-regulatory status, and small on-site generating systems.
[14]Includes consumption of energy by electricity-only and combined heat and power plants that have a regulatory status.
[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 2010 and 2011 are model results and may differ slightly from official EIA data reports.
**Sources:** 2010 and 2011 product supplied based on: U.S. Energy Information Administration (EIA), *Annual Energy Review 2011*, DOE/EIA-0384(2011) (Washington, DC, September 2012). Other 2010 data: EIA, *Petroleum Supply Annual 2010*, DOE/EIA-0340(2010)/1 (Washington, DC, July 2011). Other 2011 data: EIA, *Petroleum Supply Annual 2011*, DOE/EIA-0340(2011)/1 (Washington, DC, August 2012). **Projections:** EIA, AEO2013 National Energy Modeling System run REF2013.D102312A.

## Table A12. Petroleum product prices
(2011 dollars per gallon, unless otherwise noted)

| Sector and fuel | Reference case | | | | | | | Annual growth 2011-2040 (percent) |
|---|---|---|---|---|---|---|---|---|
| | 2010 | 2011 | 2020 | 2025 | 2030 | 2035 | 2040 | |
| **Crude oil prices (2011 dollars per barrel)** | | | | | | | | |
| Brent spot | 81.31 | 111.26 | 105.57 | 117.36 | 130.47 | 145.41 | 162.68 | 1.3% |
| West Texas Intermediate spot | 81.08 | 94.86 | 103.57 | 115.36 | 128.47 | 143.41 | 160.68 | 1.8% |
| Average imported refiners acquisition cost[1] | 77.49 | 102.65 | 102.19 | 113.48 | 125.64 | 138.70 | 154.96 | 1.4% |
| **Delivered sector product prices** | | | | | | | | |
| **Residential** | | | | | | | | |
| Propane | 2.34 | 2.13 | 1.98 | 2.09 | 2.17 | 2.25 | 2.35 | 0.3% |
| Distillate fuel oil | 3.02 | 3.66 | 3.73 | 4.03 | 4.34 | 4.67 | 5.07 | 1.1% |
| **Commercial** | | | | | | | | |
| Distillate fuel oil | 2.94 | 3.57 | 3.34 | 3.65 | 3.93 | 4.26 | 4.65 | 0.9% |
| Residual fuel oil | 1.70 | 2.87 | 2.22 | 2.49 | 2.81 | 3.13 | 3.50 | 0.7% |
| Residual fuel oil (2011 dollars per barrel) | 71.59 | 120.49 | 93.20 | 104.39 | 117.99 | 131.32 | 147.19 | 0.7% |
| **Industrial[2]** | | | | | | | | |
| Propane | 2.01 | 1.92 | 1.74 | 1.88 | 1.99 | 2.10 | 2.25 | 0.5% |
| Distillate fuel oil | 3.01 | 3.64 | 3.39 | 3.71 | 3.97 | 4.30 | 4.69 | 0.9% |
| Residual fuel oil | 1.69 | 2.82 | 2.57 | 2.84 | 3.16 | 3.48 | 3.86 | 1.1% |
| Residual fuel oil (2011 dollars per barrel) | 71.03 | 118.58 | 108.07 | 119.19 | 132.58 | 146.16 | 162.10 | 1.1% |
| **Transportation** | | | | | | | | |
| Propane | 2.33 | 2.22 | 2.07 | 2.18 | 2.26 | 2.34 | 2.44 | 0.3% |
| Ethanol (E85)[3] | 2.44 | 2.42 | 2.83 | 2.60 | 2.57 | 2.79 | 2.92 | 0.7% |
| Ethanol wholesale price | 1.75 | 2.54 | 3.00 | 2.66 | 2.28 | 2.32 | 2.48 | -0.1% |
| Motor gasoline[4] | 2.88 | 3.45 | 3.32 | 3.49 | 3.67 | 3.94 | 4.32 | 0.8% |
| Jet fuel[5] | 2.24 | 3.04 | 2.90 | 3.20 | 3.51 | 3.85 | 4.19 | 1.1% |
| Diesel fuel (distillate fuel oil)[6] | 3.07 | 3.58 | 3.65 | 3.97 | 4.22 | 4.55 | 4.94 | 1.1% |
| Residual fuel oil | 1.59 | 2.67 | 2.23 | 2.48 | 2.75 | 3.03 | 3.36 | 0.8% |
| Residual fuel oil (2011 dollars per barrel) | 66.79 | 112.11 | 93.74 | 104.23 | 115.30 | 127.30 | 141.16 | 0.8% |
| **Electric power[7]** | | | | | | | | |
| Distillate fuel oil | 2.67 | 3.23 | 3.11 | 3.41 | 3.72 | 4.05 | 4.44 | 1.1% |
| Residual fuel oil | 1.81 | 2.39 | 3.73 | 4.09 | 4.39 | 4.77 | 5.17 | 2.7% |
| Residual fuel oil (2011 dollars per barrel) | 76.16 | 100.43 | 156.82 | 171.59 | 184.59 | 200.24 | 217.18 | 2.7% |
| **Refined petroleum product prices[8]** | | | | | | | | |
| Propane | 1.37 | 1.46 | 1.16 | 1.36 | 1.53 | 1.72 | 2.00 | 1.1% |
| Motor gasoline[4] | 2.86 | 3.42 | 3.32 | 3.49 | 3.67 | 3.94 | 4.32 | 0.8% |
| Jet fuel[5] | 2.24 | 3.04 | 2.90 | 3.20 | 3.51 | 3.85 | 4.19 | 1.1% |
| Distillate fuel oil | 3.04 | 3.59 | 3.60 | 3.93 | 4.18 | 4.51 | 4.90 | 1.1% |
| Residual fuel oil | 1.66 | 2.64 | 2.39 | 2.65 | 2.93 | 3.24 | 3.59 | 1.1% |
| Residual fuel oil (2011 dollars per barrel) | 69.52 | 110.98 | 100.39 | 111.40 | 123.16 | 135.88 | 150.58 | 1.1% |
| **Average** | **2.59** | **3.11** | **3.01** | **3.22** | **3.43** | **3.72** | **4.10** | **1.0%** |

## Table A12. Petroleum product prices (continued)
(nominal dollars per gallon, unless otherwise noted)

| Sector and fuel | Reference case | | | | | | | Annual growth 2011-2040 (percent) |
|---|---|---|---|---|---|---|---|---|
| | 2010 | 2011 | 2020 | 2025 | 2030 | 2035 | 2040 | |
| **Crude oil spot prices (nominal dollars per barrel)** | | | | | | | | |
| Brent spot | 79.61 | 111.26 | 121.73 | 147.90 | 180.04 | 219.73 | 268.50 | 3.1% |
| West Texas Intermediate spot | 79.39 | 94.86 | 119.43 | 145.38 | 177.28 | 216.70 | 265.20 | 3.6% |
| Average imported refiners acquisition cost[1] | 75.87 | 102.65 | 117.84 | 143.00 | 173.38 | 209.59 | 255.76 | 3.2% |
| **Delivered sector product prices** | | | | | | | | |
| **Residential** | | | | | | | | |
| Propane | 2.29 | 2.13 | 2.29 | 2.63 | 2.99 | 3.40 | 3.88 | 2.1% |
| Distillate fuel oil | 2.96 | 3.66 | 4.30 | 5.08 | 5.98 | 7.06 | 8.37 | 2.9% |
| **Commercial** | | | | | | | | |
| Distillate fuel oil | 2.88 | 3.57 | 3.86 | 4.61 | 5.42 | 6.44 | 7.68 | 2.7% |
| Residual fuel oil | 1.67 | 2.87 | 2.56 | 3.13 | 3.88 | 4.72 | 5.78 | 2.4% |
| Residual fuel oil (nominal dollars per barrel) | 70.09 | 120.49 | 107.46 | 131.55 | 162.83 | 198.44 | 242.92 | 2.4% |
| **Industrial[2]** | | | | | | | | |
| Propane | 1.97 | 1.92 | 2.00 | 2.38 | 2.75 | 3.18 | 3.71 | 2.3% |
| Distillate fuel oil | 2.95 | 3.64 | 3.91 | 4.67 | 5.48 | 6.49 | 7.74 | 2.6% |
| Residual fuel oil | 1.66 | 2.82 | 2.97 | 3.58 | 4.36 | 5.26 | 6.37 | 2.8% |
| Residual fuel oil (nominal dollars per barrel) | 69.54 | 118.58 | 124.61 | 150.20 | 182.96 | 220.86 | 267.54 | 2.8% |
| **Transportation** | | | | | | | | |
| Propane | 2.28 | 2.22 | 2.39 | 2.75 | 3.12 | 3.53 | 4.03 | 2.1% |
| Ethanol (E85)[3] | 2.39 | 2.42 | 3.26 | 3.28 | 3.55 | 4.21 | 4.82 | 2.4% |
| Ethanol wholesale price | 1.71 | 2.54 | 3.46 | 3.36 | 3.14 | 3.51 | 4.09 | 1.7% |
| Motor gasoline[4] | 2.82 | 3.45 | 3.83 | 4.40 | 5.06 | 5.95 | 7.13 | 2.5% |
| Jet fuel[5] | 2.19 | 3.04 | 3.35 | 4.04 | 4.85 | 5.82 | 6.92 | 2.9% |
| Diesel fuel (distillate fuel oil)[6] | 3.00 | 3.58 | 4.20 | 5.00 | 5.83 | 6.87 | 8.15 | 2.9% |
| Residual fuel oil | 1.56 | 2.67 | 2.57 | 3.13 | 3.79 | 4.58 | 5.55 | 2.6% |
| Residual fuel oil (nominal dollars per barrel) | 65.40 | 112.11 | 108.09 | 131.35 | 159.10 | 192.35 | 232.98 | 2.6% |
| **Electric power[7]** | | | | | | | | |
| Distillate fuel oil | 2.61 | 3.23 | 3.59 | 4.30 | 5.13 | 6.13 | 7.33 | 2.9% |
| Residual fuel oil | 1.78 | 2.39 | 4.31 | 5.15 | 6.06 | 7.20 | 8.53 | 4.5% |
| Residual fuel oil (nominal dollars per barrel) | 74.57 | 100.43 | 180.83 | 216.23 | 254.72 | 302.58 | 358.45 | 4.5% |
| **Refined petroleum product prices[8]** | | | | | | | | |
| Propane | 1.35 | 1.46 | 1.34 | 1.71 | 2.11 | 2.60 | 3.30 | 2.9% |
| Motor gasoline[4] | 2.81 | 3.42 | 3.83 | 4.40 | 5.06 | 5.95 | 7.13 | 2.6% |
| Jet fuel[5] | 2.19 | 3.04 | 3.35 | 4.04 | 4.85 | 5.82 | 6.92 | 2.9% |
| Distillate fuel oil | 2.98 | 3.59 | 4.15 | 4.95 | 5.77 | 6.81 | 8.09 | 2.8% |
| Residual fuel oil | 1.62 | 2.64 | 2.76 | 3.34 | 4.05 | 4.89 | 5.92 | 2.8% |
| Residual fuel oil (nominal dollars per barrel) | 68.06 | 110.98 | 115.76 | 140.38 | 169.95 | 205.33 | 248.53 | 2.8% |
| **Average** | **2.54** | **3.11** | **3.47** | **4.06** | **4.74** | **5.62** | **6.76** | **2.7%** |

[1]Weighted average price delivered to U.S. refiners.
[2]Includes combined heat and power plants that have a non-regulatory status, and small on-site generating systems.
[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 that have a regulatory status.
[8]Weighted averages of end-use fuel prices are derived from the prices in each sector and the corresponding sectoral consumption.
Note: Data for 2010 and 2011 are model results and may differ slightly from official EIA data reports.
**Sources:** 2010 and 2011 prices for motor gasoline, distillate fuel oil, and jet fuel are based on: U.S. Energy Information Administration (EIA), *Petroleum Marketing Monthly*, DOE/EIA-0380(2012/08) (Washington, DC, August 2012). 2010 and 2011 crude oil spot prices: Thomson Reuters. 2010 and 2011 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." 2010 and 2011 electric power prices based on: EIA, *Monthly Energy Review*, DOE/EIA-0035(2012/09) (Washington, DC, September 2012). 2010 and 2011 E85 prices derived from monthly prices in the Clean Cities Alternative Fuel Price Report. 2010 and 2011 wholesale ethanol prices derived from Bloomberg U.S. average rack price. **Projections:** EIA, AEO2013 National Energy Modeling System run REF2013.D102312A.

**Table A13. Natural gas supply, disposition, and prices**
(trillion cubic feet per year, unless otherwise noted)

| Supply, disposition, and prices | Reference case | | | | | | | Annual growth 2011-2040 (percent) |
|---|---|---|---|---|---|---|---|---|
| | 2010 | 2011 | 2020 | 2025 | 2030 | 2035 | 2040 | |
| **Supply** | | | | | | | | |
| Dry gas production[1] | 21.33 | 23.00 | 26.61 | 28.59 | 29.79 | 31.35 | 33.14 | 1.3% |
| Supplemental natural gas[2] | 0.06 | 0.06 | 0.06 | 0.06 | 0.06 | 0.06 | 0.06 | 0.2% |
| Net imports | 2.60 | 1.95 | -0.14 | -1.58 | -2.10 | -2.55 | -3.55 | - - |
| Pipeline[3] | 2.24 | 1.67 | 0.13 | -0.52 | -0.67 | -1.09 | -2.09 | - - |
| Liquefied natural gas | 0.37 | 0.28 | -0.26 | -1.06 | -1.43 | -1.46 | -1.46 | - - |
| **Total supply** | **24.00** | **25.01** | **26.54** | **27.07** | **27.75** | **28.86** | **29.65** | **0.6%** |
| **Consumption by sector** | | | | | | | | |
| Residential | 4.78 | 4.72 | 4.52 | 4.44 | 4.36 | 4.24 | 4.14 | -0.5% |
| Commercial | 3.10 | 3.16 | 3.32 | 3.35 | 3.42 | 3.51 | 3.60 | 0.4% |
| Industrial[4] | 6.52 | 6.77 | 7.68 | 7.82 | 7.79 | 7.84 | 7.90 | 0.5% |
| Natural-gas-to-liquids heat and power[5] | 0.00 | 0.00 | 0.13 | 0.16 | 0.21 | 0.26 | 0.33 | - - |
| Natural gas to liquids production[6] | 0.00 | 0.00 | 0.14 | 0.17 | 0.22 | 0.28 | 0.35 | - - |
| Electric power[7] | 7.39 | 7.60 | 8.23 | 8.45 | 8.89 | 9.44 | 9.50 | 0.8% |
| Transportation[8] | 0.04 | 0.04 | 0.08 | 0.12 | 0.26 | 0.59 | 1.04 | 11.9% |
| Pipeline fuel | 0.67 | 0.68 | 0.70 | 0.71 | 0.73 | 0.74 | 0.76 | 0.4% |
| Lease and plant fuel[9] | 1.28 | 1.39 | 1.54 | 1.64 | 1.70 | 1.81 | 1.93 | 1.1% |
| **Total consumption** | **23.78** | **24.37** | **26.32** | **26.87** | **27.57** | **28.71** | **29.54** | **0.7%** |
| **Discrepancy[10]** | **0.22** | **0.64** | **0.22** | **0.20** | **0.18** | **0.15** | **0.12** | **- -** |
| **Natural gas spot price at Henry Hub** | | | | | | | | |
| (2011 dollars per million Btu) | 4.46 | 3.98 | 4.13 | 4.87 | 5.40 | 6.32 | 7.83 | 2.4% |
| (nominal dollars per million Btu) | 4.37 | 3.98 | 4.77 | 6.14 | 7.45 | 9.55 | 12.92 | 4.1% |
| **Delivered natural gas prices** | | | | | | | | |
| **(2011 dollars per thousand cubic feet)** | | | | | | | | |
| Residential | 11.62 | 11.05 | 12.05 | 12.97 | 13.68 | 14.93 | 16.74 | 1.4% |
| Commercial | 9.61 | 9.04 | 9.69 | 10.43 | 10.94 | 11.95 | 13.52 | 1.4% |
| Industrial[4] | 5.61 | 5.00 | 5.66 | 6.29 | 6.71 | 7.62 | 9.09 | 2.1% |
| Electric power[7] | 5.37 | 4.87 | 5.00 | 5.70 | 6.18 | 7.13 | 8.55 | 2.0% |
| Transportation[11] | 16.89 | 16.51 | 17.26 | 18.39 | 19.34 | 20.31 | 21.68 | 0.9% |
| **Average[12]** | **7.44** | **6.83** | **7.23** | **7.93** | **8.45** | **9.51** | **11.18** | **1.7%** |
| **(nominal dollars per thousand cubic feet)** | | | | | | | | |
| Residential | 11.38 | 11.05 | 13.89 | 16.34 | 18.87 | 22.57 | 27.63 | 3.2% |
| Commercial | 9.41 | 9.04 | 11.17 | 13.14 | 15.10 | 18.06 | 22.31 | 3.2% |
| Industrial[4] | 5.49 | 5.00 | 6.52 | 7.93 | 9.26 | 11.51 | 14.99 | 3.9% |
| Electric power[7] | 5.26 | 4.87 | 5.76 | 7.18 | 8.53 | 10.77 | 14.12 | 3.7% |
| Transportation[11] | 16.54 | 16.51 | 19.90 | 23.17 | 26.68 | 30.70 | 35.79 | 2.7% |
| **Average[12]** | **7.28** | **6.83** | **8.34** | **9.99** | **11.66** | **14.37** | **18.46** | **3.5%** |

[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 that have a non-regulatory status, and small on-site generating systems.
[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 converted into liquid fuel.
[7]Includes consumption of energy by electricity-only and combined heat and power plants that have a regulatory status.
[8]Natural gas used as vehicle fuel.
[9]Represents natural gas used in well, field, and lease operations, in natural gas processing plant machinery, and for liquefaction in export facilities.
[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, 2010 and 2011 values include net storage injections.
[11]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.
- - = Not applicable.
Note: Totals may not equal sum of components due to independent rounding. Data for 2010 and 2011 are model results and may differ slightly from official EIA data reports.
**Sources:** 2010 supply values; lease, plant, and pipeline fuel consumption; and residential, commercial, and industrial delivered prices: U.S. Energy Information Administration (EIA), *Natural Gas Annual 2010*, DOE/EIA-0131(2010) (Washington, DC, December 2011). 2011 supply values; lease, plant, and pipeline fuel consumption; and residential, commercial, and industrial delivered prices: EIA, *Natural Gas Monthly*, DOE/EIA-0130(2012/07) (Washington, DC, July 2012). Other 2010 and 2011 consumption based on: EIA, *Annual Energy Review 2011*, DOE/EIA-0384(2011) (Washington, DC, September 2012). 2010 and 2011 natural gas price at Henry Hub based on daily spot prices published in Natural Gas Intelligence. 2010 and 2011 electric power prices: EIA, *Electric Power Monthly*, DOE/EIA-0226, April 2011 and April 2012, Table 4.2, and EIA, *State Energy Data Report 2010*, DOE/EIA-0214(2010) (Washington, DC, June 2012). 2010 transportation sector delivered prices are based on: EIA, *Natural Gas Annual 2010*, DOE/EIA-0131(2010) (Washington, DC, December 2011) and estimated state taxes, federal taxes, and dispensing costs or charges. 2011 transportation sector delivered prices are model results. **Projections:** EIA, AEO2013 National Energy Modeling System run REF2013.D102312A.

## Table A14. Oil and gas supply

| Production and supply | Reference case | | | | | | | Annual growth 2011-2040 (percent) |
|---|---|---|---|---|---|---|---|---|
| | 2010 | 2011 | 2020 | 2025 | 2030 | 2035 | 2040 | |
| **Crude oil** | | | | | | | | |
| **Lower 48 average wellhead price[1] (2011 dollars per barrel)** | **76.78** | **96.55** | **103.49** | **115.61** | **129.26** | **143.31** | **160.38** | **1.8%** |
| **Production (million barrels per day)[2]** | | | | | | | | |
| United States total | 5.47 | 5.67 | 7.47 | 6.79 | 6.30 | 6.26 | 6.13 | 0.3% |
| Lower 48 onshore | 3.21 | 3.67 | 5.29 | 4.99 | 4.48 | 4.19 | 3.97 | 0.3% |
| Tight oil[3] | 0.82 | 1.22 | 2.81 | 2.63 | 2.19 | 2.06 | 2.02 | 1.7% |
| Carbon dioxide enhanced oil recovery | 0.28 | 0.24 | 0.29 | 0.43 | 0.56 | 0.65 | 0.66 | 3.5% |
| Other | 2.11 | 2.20 | 2.19 | 1.93 | 1.72 | 1.48 | 1.30 | -1.8% |
| Lower 48 offshore | 1.67 | 1.43 | 1.69 | 1.46 | 1.44 | 1.72 | 1.75 | 0.7% |
| Alaska | 0.60 | 0.57 | 0.49 | 0.35 | 0.38 | 0.35 | 0.41 | -1.1% |
| **Lower 48 end of year reserves[2] (billion barrels)** | **21.46** | **21.36** | **24.63** | **24.37** | **24.92** | **26.19** | **26.72** | **0.8%** |
| **Natural gas** | | | | | | | | |
| **Natural gas spot price at Henry Hub** (2011 dollars per million Btu) | 4.46 | 3.98 | 4.13 | 4.87 | 5.40 | 6.32 | 7.83 | 2.4% |
| **Dry production (trillion cubic feet)[4]** | | | | | | | | |
| United States total | 21.33 | 23.00 | 26.61 | 28.59 | 29.79 | 31.35 | 33.14 | 1.3% |
| Lower 48 onshore | 18.54 | 20.54 | 24.27 | 25.67 | 26.26 | 27.35 | 29.12 | 1.2% |
| Associated-dissolved[5] | 1.47 | 1.54 | 2.14 | 1.99 | 1.43 | 1.26 | 1.09 | -1.2% |
| Non-associated | 17.07 | 19.00 | 22.13 | 23.67 | 24.83 | 26.10 | 28.03 | 1.4% |
| Tight gas | 6.34 | 5.86 | 6.40 | 6.56 | 6.67 | 6.96 | 7.34 | 0.8% |
| Shale gas | 4.86 | 7.85 | 11.05 | 12.84 | 14.17 | 15.33 | 16.70 | 2.6% |
| Coalbed methane | 1.69 | 1.71 | 1.71 | 1.66 | 1.69 | 1.73 | 2.11 | 0.7% |
| Other | 4.18 | 3.58 | 2.97 | 2.61 | 2.31 | 2.07 | 1.87 | -2.2% |
| Lower 48 offshore | 2.44 | 2.11 | 2.07 | 2.19 | 2.34 | 2.81 | 2.85 | 1.0% |
| Associated-dissolved[5] | 0.59 | 0.54 | 0.66 | 0.64 | 0.60 | 0.74 | 0.74 | 1.1% |
| Non-associated | 1.85 | 1.58 | 1.41 | 1.55 | 1.73 | 2.07 | 2.11 | 1.0% |
| Alaska | 0.35 | 0.35 | 0.28 | 0.73 | 1.19 | 1.18 | 1.18 | 4.3% |
| **Lower 48 end of year dry reserves[4] (trillion cubic feet)** | **295.79** | **298.96** | **332.51** | **342.08** | **350.65** | **356.26** | **359.97** | **0.6%** |
| **Supplemental gas supplies (trillion cubic feet)[6]** | **0.06** | **0.06** | **0.06** | **0.06** | **0.06** | **0.06** | **0.06** | **0.2%** |
| **Total lower 48 wells drilled (thousands)** | **43.27** | **41.10** | **48.84** | **54.26** | **57.91** | **63.76** | **76.65** | **2.2%** |

[1]Represents lower 48 onshore and offshore supplies.
[2]Includes lease condensate.
[3]Tight oil represents resources in low-permeability reservoirs, including shale and chalk formations. The specific plays included in the tight oil category are Bakken/Three Forks/Sanish, Eagle Ford, Woodford, Austin Chalk, Spraberry, Niobrara, Avalon/Bone Springs, and Monterey.
[4]Marketed production (wet) minus extraction losses.
[5]Gas which occurs in crude oil reservoirs either as free gas (associated) or as gas in solution with crude oil (dissolved).
[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 2010 and 2011 are model results and may differ slightly from official EIA data reports.
**Sources:** 2010 and 2011 crude oil lower 48 average wellhead price: U.S. Energy Information Administration (EIA), *Petroleum Marketing Monthly*, DOE/EIA-0380(2012/08) (Washington, DC, August 2012). 2010 and 2011 lower 48 onshore, lower 48 offshore, and Alaska crude oil production: EIA, *Petroleum Supply Annual 2011*, DOE/EIA-0340(2011)/1 (Washington, DC, August 2012). 2010 U.S. crude oil and natural gas reserves: EIA, *U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves*, DOE/EIA-0216(2010) (Washington, DC, August 2012). 2010 Alaska and total natural gas production, and supplemental gas supplies: EIA, *Natural Gas Annual 2010*, DOE/EIA-0131(2010) (Washington, DC, December 2011). 2010 and 2011 natural gas spot price at Henry Hub based on daily data from Natural Gas Intelligence. 2011 Alaska and total natural gas production, and supplemental gas supplies: EIA, *Natural Gas Monthly*, DOE/EIA-0130Natural Gas Monthly, DOE/EIA-0130(2012/07) (Washington, DC, July 2012). Other 2010 and 2011 values: EIA, Office of Energy Analysis. **Projections:** EIA, AEO2013 National Energy Modeling System run REF2013.D102312A.

## Table A15. Coal supply, disposition, and prices
(million short tons per year, unless otherwise noted)

| Supply, disposition, and prices | Reference case | | | | | | | Annual growth 2011-2040 (percent) |
|---|---|---|---|---|---|---|---|---|
| | 2010 | 2011 | 2020 | 2025 | 2030 | 2035 | 2040 | |
| **Production[1]** | | | | | | | | |
| Appalachia | 336 | 337 | 288 | 295 | 295 | 289 | 283 | -0.6% |
| Interior | 156 | 171 | 198 | 203 | 212 | 217 | 226 | 1.0% |
| West | 592 | 588 | 585 | 616 | 646 | 664 | 658 | 0.4% |
| East of the Mississippi | 446 | 456 | 438 | 447 | 456 | 455 | 453 | -0.0% |
| West of the Mississippi | 638 | 639 | 633 | 666 | 697 | 716 | 714 | 0.4% |
| **Total** | **1,084** | **1,096** | **1,071** | **1,113** | **1,153** | **1,171** | **1,167** | **0.2%** |
| **Waste coal supplied[2]** | **14** | **13** | **19** | **21** | **20** | **23** | **27** | **2.7%** |
| **Net imports** | | | | | | | | |
| Imports[3] | 18 | 11 | 2 | 5 | 5 | 22 | 36 | 4.0% |
| Exports | 82 | 107 | 127 | 129 | 144 | 158 | 159 | 1.4% |
| **Total** | **-64** | **-96** | **-125** | **-124** | **-139** | **-136** | **-123** | **0.9%** |
| **Total supply[4]** | **1,034** | **1,012** | **966** | **1,010** | **1,034** | **1,058** | **1,071** | **0.2%** |
| **Consumption by sector** | | | | | | | | |
| Residential and commercial | 3 | 3 | 3 | 3 | 3 | 3 | 3 | -0.3% |
| Coke plants | 21 | 21 | 23 | 22 | 20 | 18 | 18 | -0.7% |
| Other industrial[5] | 49 | 46 | 50 | 50 | 50 | 51 | 52 | 0.4% |
| Coal-to-liquids heat and power | 0 | 0 | 0 | 3 | 5 | 6 | 8 | - - |
| Coal to liquids production | 0 | 0 | 0 | 3 | 4 | 5 | 6 | - - |
| Electric power[6] | 975 | 929 | 890 | 929 | 953 | 975 | 984 | 0.2% |
| **Total** | **1,049** | **999** | **966** | **1,010** | **1,034** | **1,058** | **1,071** | **0.2%** |
| **Discrepancy and stock change[7]** | **-14** | **13** | **0** | **-0** | **0** | **1** | **0** | **- -** |
| **Average minemouth price[8]** | | | | | | | | |
| (2011 dollars per short ton) | 36.37 | 41.16 | 49.26 | 52.02 | 55.64 | 58.57 | 61.28 | 1.4% |
| (2011 dollars per million Btu) | 1.80 | 2.04 | 2.45 | 2.60 | 2.79 | 2.94 | 3.08 | 1.4% |
| **Delivered prices[9]** | | | | | | | | |
| **(2011 dollars per short ton)** | | | | | | | | |
| Coke plants | 156.87 | 184.44 | 229.19 | 245.15 | 264.13 | 279.68 | 290.84 | 1.6% |
| Other industrial[5] | 65.76 | 70.68 | 72.44 | 74.98 | 78.25 | 81.84 | 85.63 | 0.7% |
| Coal to liquids | - - | - - | - - | 49.54 | 47.71 | 53.07 | 55.60 | - - |
| Electric power[6] | | | | | | | | |
| (2011 dollars per short ton) | 45.21 | 46.38 | 47.91 | 51.14 | 54.37 | 57.39 | 60.77 | 0.9% |
| (2011 dollars per million Btu) | 2.30 | 2.38 | 2.52 | 2.69 | 2.87 | 3.03 | 3.20 | 1.0% |
| **Average** | **48.40** | **50.64** | **53.47** | **56.58** | **59.53** | **62.37** | **65.70** | **0.9%** |
| Exports[10] | 122.98 | 148.86 | 168.73 | 172.99 | 177.76 | 177.60 | 176.05 | 0.6% |

# Table A15. Coal supply, disposition, and prices (continued)

(million short tons per year, unless otherwise noted)

| Supply, disposition, and prices | Reference case | | | | | | | Annual growth 2011-2040 (percent) |
|---|---|---|---|---|---|---|---|---|
| | 2010 | 2011 | 2020 | 2025 | 2030 | 2035 | 2040 | |
| **Average minemouth price[8]** | | | | | | | | |
| (nominal dollars per short ton) | 35.61 | 41.16 | 56.81 | 65.55 | 76.78 | 88.51 | 101.14 | 3.1% |
| (nominal dollars per million Btu) | 1.76 | 2.04 | 2.83 | 3.27 | 3.85 | 4.44 | 5.08 | 3.2% |
| **Delivered prices[9]** | | | | | | | | |
| **(nominal dollars per short ton)** | | | | | | | | |
| Coke plants | 153.59 | 184.44 | 264.27 | 308.93 | 364.48 | 422.61 | 480.01 | 3.4% |
| Other industrial[5] | 64.38 | 70.68 | 83.52 | 94.49 | 107.97 | 123.66 | 141.33 | 2.4% |
| Coal to liquids | - - | - - | - - | 62.44 | 65.84 | 80.19 | 91.77 | - - |
| Electric power[6] | | | | | | | | |
| (nominal dollars per short ton) | 44.27 | 46.38 | 55.24 | 64.45 | 75.02 | 86.73 | 100.29 | 2.7% |
| (nominal dollars per million Btu) | 2.25 | 2.38 | 2.90 | 3.39 | 3.96 | 4.58 | 5.28 | 2.8% |
| **Average** | **47.39** | **50.64** | **61.66** | **71.30** | **82.14** | **94.24** | **108.43** | **2.7%** |
| Exports[10] | 120.41 | 148.86 | 194.56 | 217.99 | 245.30 | 268.37 | 290.56 | 2.3% |

[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 that have a non-regulatory status, and small on-site generating systems. Excludes all coal use in the coal-to-liquids process.
[6]Includes all electricity-only and combined heat and power plants that have a regulatory status.
[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. Prices weighted by production, which differs from average minemouth prices published in EIA data reports where it is weighted by reported sales.
[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 2010 and 2011 are model results and may differ slightly from official EIA data reports.
**Sources:** 2010 and 2011 data based on: U.S. Energy Information Administration (EIA), *Annual Coal Report 2011*, DOE/EIA-0584(2011) (Washington, DC, November 2012); EIA, *Quarterly Coal Report, October-December 2011*, DOE/EIA-0121(2011/4Q) (Washington, DC, March 2012); and EIA, AEO2013 National Energy Modeling System run REF2013.D102312A. **Projections:** EIA, AEO2013 National Energy Modeling System run REF2013.D102312A.

**Table A16. Renewable energy generating capacity and generation**
(gigawatts, unless otherwise noted)

| Net summer capacity and generation | Reference case 2010 | 2011 | 2020 | 2025 | 2030 | 2035 | 2040 | Annual growth 2011-2040 (percent) |
|---|---|---|---|---|---|---|---|---|
| **Electric power sector[1]** | | | | | | | | |
| **Net summer capacity** | | | | | | | | |
| Conventional hydropower | 77.82 | 77.87 | 78.34 | 78.94 | 79.11 | 79.63 | 80.31 | 0.1% |
| Geothermal[2] | 2.38 | 2.38 | 3.63 | 4.34 | 5.70 | 6.60 | 7.46 | 4.0% |
| Municipal waste[3] | 3.26 | 3.34 | 3.44 | 3.44 | 3.44 | 3.44 | 3.44 | 0.1% |
| Wood and other biomass[4] | 2.38 | 2.37 | 2.82 | 2.83 | 2.85 | 3.16 | 3.70 | 1.6% |
| Solar thermal | 0.49 | 0.49 | 1.35 | 1.35 | 1.35 | 1.35 | 1.35 | 3.6% |
| Solar photovoltaic[5] | 0.37 | 1.01 | 5.37 | 5.91 | 6.80 | 11.84 | 24.54 | 11.6% |
| Wind | 39.40 | 45.68 | 58.81 | 59.62 | 61.30 | 69.14 | 86.83 | 2.2% |
| Offshore wind | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | - - |
| **Total electric power sector capacity** | **126.09** | **133.14** | **153.75** | **156.43** | **160.54** | **175.17** | **207.63** | **1.5%** |
| **Generation (billion kilowatthours)** | | | | | | | | |
| Conventional hydropower | 258.46 | 323.14 | 288.54 | 291.38 | 292.39 | 295.18 | 297.28 | -0.3% |
| Geothermal[2] | 15.22 | 16.70 | 25.28 | 30.98 | 42.02 | 49.36 | 56.40 | 4.3% |
| Biogenic municipal waste[6] | 15.78 | 16.62 | 14.09 | 14.09 | 14.09 | 14.09 | 14.10 | -0.6% |
| Wood and other biomass | 11.45 | 10.50 | 54.45 | 68.99 | 65.48 | 66.41 | 75.64 | 7.0% |
| Dedicated plants | 10.37 | 9.35 | 14.85 | 15.12 | 15.30 | 17.62 | 21.59 | 2.9% |
| Cofiring | 1.07 | 1.16 | 39.60 | 53.87 | 50.18 | 48.79 | 54.05 | 14.2% |
| Solar thermal | 0.79 | 0.81 | 2.74 | 2.74 | 2.73 | 2.73 | 2.73 | 4.3% |
| Solar photovoltaic[5] | 0.42 | 0.97 | 9.83 | 10.99 | 13.40 | 24.81 | 56.22 | 15.0% |
| Wind | 94.62 | 119.63 | 163.48 | 166.73 | 172.11 | 195.46 | 251.94 | 2.6% |
| Offshore wind | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | - - |
| **Total electric power sector generation** | **396.73** | **488.38** | **558.41** | **585.90** | **602.22** | **648.05** | **754.32** | **1.5%** |
| **End-use sectors[7]** | | | | | | | | |
| **Net summer capacity** | | | | | | | | |
| Conventional hydropower | 0.33 | 0.33 | 0.33 | 0.33 | 0.33 | 0.33 | 0.33 | 0.0% |
| Geothermal | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | - - |
| Municipal waste[8] | 0.35 | 0.46 | 0.46 | 0.46 | 0.46 | 0.46 | 0.46 | 0.0% |
| Biomass | 4.57 | 4.92 | 6.87 | 7.62 | 8.34 | 9.16 | 10.18 | 2.5% |
| Solar photovoltaic[5] | 1.82 | 3.02 | 15.63 | 16.95 | 18.94 | 21.53 | 25.08 | 7.6% |
| Wind | 0.17 | 0.21 | 0.87 | 0.92 | 1.05 | 1.23 | 1.51 | 7.1% |
| **Total end-use sector capacity** | **7.24** | **8.93** | **24.15** | **26.28** | **29.12** | **32.71** | **37.55** | **5.1%** |
| **Generation (billion kilowatthours)** | | | | | | | | |
| Conventional hydropower | 1.75 | 1.89 | 1.82 | 1.82 | 1.82 | 1.82 | 1.82 | -0.1% |
| Geothermal | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | - - |
| Municipal waste[8] | 1.94 | 2.04 | 3.55 | 3.55 | 3.55 | 3.55 | 3.55 | 1.9% |
| Biomass | 25.73 | 26.75 | 36.95 | 41.35 | 45.55 | 50.32 | 56.25 | 2.6% |
| Solar photovoltaic[5] | 2.85 | 4.71 | 24.53 | 26.69 | 29.91 | 34.10 | 39.97 | 7.7% |
| Wind | 0.22 | 0.28 | 1.23 | 1.31 | 1.50 | 1.76 | 2.15 | 7.4% |
| **Total end-use sector generation** | **32.48** | **35.68** | **68.09** | **74.72** | **82.33** | **91.56** | **103.74** | **3.7%** |

## Table A16. Renewable energy generating capacity and generation (continued)
(gigawatts, unless otherwise noted)

| Net summer capacity and generation | Reference case | | | | | | | Annual growth 2011-2040 (percent) |
|---|---|---|---|---|---|---|---|---|
| | 2010 | 2011 | 2020 | 2025 | 2030 | 2035 | 2040 | |
| **Total, all sectors** | | | | | | | | |
| **Net summer capacity** | | | | | | | | |
| Conventional hydropower | 78.15 | 78.20 | 78.66 | 79.27 | 79.43 | 79.96 | 80.64 | 0.1% |
| Geothermal | 2.38 | 2.38 | 3.63 | 4.34 | 5.70 | 6.60 | 7.46 | 4.0% |
| Municipal waste | 3.61 | 3.80 | 3.89 | 3.89 | 3.89 | 3.89 | 3.89 | 0.1% |
| Wood and other biomass[4] | 6.95 | 7.29 | 9.69 | 10.45 | 11.19 | 12.32 | 13.88 | 2.2% |
| Solar[5] | 2.67 | 4.52 | 22.35 | 24.22 | 27.09 | 34.73 | 50.96 | 8.7% |
| Wind | 39.57 | 45.88 | 59.68 | 60.54 | 62.35 | 70.37 | 88.35 | 2.3% |
| **Total capacity, all sectors** | **133.33** | **142.06** | **177.90** | **182.71** | **189.66** | **207.88** | **245.17** | **1.9%** |
| **Generation (billion kilowatthours)** | | | | | | | | |
| Conventional hydropower | 260.20 | 325.03 | 290.37 | 293.20 | 294.21 | 297.01 | 299.11 | -0.3% |
| Geothermal | 15.22 | 16.70 | 25.28 | 30.98 | 42.02 | 49.36 | 56.40 | 4.3% |
| Municipal waste | 17.71 | 18.66 | 17.63 | 17.64 | 17.64 | 17.64 | 17.64 | -0.2% |
| Wood and other biomass | 37.17 | 37.26 | 91.40 | 110.34 | 111.03 | 116.73 | 131.89 | 4.5% |
| Solar[5] | 4.05 | 6.50 | 37.10 | 40.42 | 46.04 | 61.65 | 98.92 | 9.8% |
| Wind | 94.85 | 119.91 | 164.71 | 168.04 | 173.61 | 197.22 | 254.10 | 2.6% |
| **Total generation, all sectors** | **429.21** | **524.06** | **626.49** | **660.62** | **684.55** | **739.61** | **858.06** | **1.7%** |

[1]Includes electricity-only and combined heat and power plants that have a regulatory status.
[2]Includes both hydrothermal resources (hot water and steam) and near-field enhanced geothermal systems (EGS). Near-field EGS potential occurs on known hydrothermal sites, however this potential requires the addition of external fluids for electricity generation and is only available after 2025.
[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]Does not include off-grid photovoltaics (PV). Based on annual PV shipments from 1989 through 2010, EIA estimates that as much as 245 megawatts of remote electricity generation PV applications (i.e., off-grid power systems) were in service in 2010, plus an additional 558 megawatts in communications, transportation, and assorted other non-grid-connected, specialized applications. See U.S. Energy Information Administration, , DOE/EIA-0384(2011) (Washington, DC, September 2012), Table 10.9 (annual PV shipments, 1989-2010). 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.
[6]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 U.S. Energy Information Administration estimates that in 2011 approximately 6 billion kilowatthours of electricity were generated from a municipal waste stream containing petroleum-derived plastics and other non-renewable sources. See U.S. Energy Information Administration, *Methodology for Allocating Municipal Solid Waste to Biogenic and Non-Biogenic Energy* (Washington, DC, May 2007).
[7]Includes combined heat and power plants and electricity-only plants in the commercial and industrial sectors that have a non-regulatory status; 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 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 2010 and 2011 are model results and may differ slightly from official EIA data reports.
**Sources:** 2010 and 2011 capacity: U.S. Energy Information Administration (EIA), Form EIA-860, "Annual Electric Generator Report" (preliminary). 2010 and 2011 generation: EIA, *Annual Energy Review 2011*, DOE/EIA-0384(2011) (Washington, DC, September 2012). **Projections:** EIA, AEO2013 National Energy Modeling System run REF2013.D102312A.

## Table A17. Renewable energy consumption by sector and source
(quadrillion Btu per year)

| Sector and source | Reference case | | | | | | | Annual growth 2011-2040 (percent) |
|---|---|---|---|---|---|---|---|---|
| | 2010 | 2011 | 2020 | 2025 | 2030 | 2035 | 2040 | |
| **Marketed renewable energy[1]** | | | | | | | | |
| **Residential (wood)** | **0.44** | **0.45** | **0.44** | **0.44** | **0.45** | **0.45** | **0.45** | **0.1%** |
| **Commercial (biomass)** | **0.11** | **0.13** | **0.13** | **0.13** | **0.13** | **0.13** | **0.13** | **0.0%** |
| **Industrial[2]** | **2.32** | **2.18** | **2.53** | **2.67** | **2.82** | **3.08** | **3.65** | **1.8%** |
| Conventional hydroelectric | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.0% |
| Municipal waste[3] | 0.18 | 0.18 | 0.18 | 0.18 | 0.18 | 0.18 | 0.18 | 0.1% |
| Biomass | 1.27 | 1.31 | 1.51 | 1.65 | 1.77 | 1.91 | 2.08 | 1.6% |
| Biofuels heat and coproducts | 0.85 | 0.67 | 0.82 | 0.82 | 0.85 | 0.97 | 1.37 | 2.5% |
| **Transportation** | **1.14** | **1.22** | **1.60** | **1.58** | **1.58** | **1.71** | **2.21** | **2.1%** |
| Ethanol used in E85[4] | 0.00 | 0.03 | 0.05 | 0.09 | 0.11 | 0.10 | 0.11 | 4.3% |
| Ethanol used in gasoline blending | 1.09 | 1.06 | 1.35 | 1.26 | 1.19 | 1.15 | 1.15 | 0.3% |
| Biodiesel used in distillate blending | 0.03 | 0.12 | 0.16 | 0.16 | 0.16 | 0.16 | 0.16 | 1.0% |
| Liquids from biomass | 0.00 | 0.00 | 0.02 | 0.04 | 0.10 | 0.27 | 0.76 | - - |
| Renewable diesel and gasoline[5] | 0.01 | 0.00 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 7.9% |
| **Electric power[6]** | **3.85** | **4.74** | **5.49** | **5.77** | **5.93** | **6.38** | **7.44** | **1.6%** |
| Conventional hydroelectric | 2.52 | 3.15 | 2.82 | 2.84 | 2.85 | 2.88 | 2.90 | -0.3% |
| Geothermal | 0.15 | 0.16 | 0.25 | 0.30 | 0.41 | 0.48 | 0.55 | 4.3% |
| Biogenic municipal waste[7] | 0.05 | 0.05 | 0.07 | 0.07 | 0.07 | 0.07 | 0.07 | 0.8% |
| Biomass | 0.20 | 0.19 | 0.64 | 0.79 | 0.76 | 0.78 | 0.88 | 5.4% |
| Dedicated plants | 0.17 | 0.15 | 0.24 | 0.24 | 0.24 | 0.28 | 0.33 | 2.7% |
| Cofiring | 0.02 | 0.04 | 0.40 | 0.55 | 0.51 | 0.50 | 0.55 | 9.9% |
| Solar thermal | 0.01 | 0.01 | 0.03 | 0.03 | 0.03 | 0.03 | 0.03 | 4.3% |
| Solar photovoltaic | 0.00 | 0.01 | 0.10 | 0.11 | 0.13 | 0.24 | 0.55 | 15.0% |
| Wind | 0.92 | 1.17 | 1.59 | 1.63 | 1.68 | 1.91 | 2.46 | 2.6% |
| **Total marketed renewable energy** | **7.85** | **8.71** | **10.19** | **10.58** | **10.89** | **11.75** | **13.87** | **1.6%** |
| **Sources of ethanol** | | | | | | | | |
| from corn and other starch | 1.13 | 1.18 | 1.29 | 1.25 | 1.22 | 1.17 | 1.13 | -0.1% |
| from cellulose | 0.00 | 0.00 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 13.8% |
| Net imports | -0.03 | -0.09 | 0.09 | 0.08 | 0.06 | 0.06 | 0.11 | - - |
| **Total** | **1.09** | **1.09** | **1.40** | **1.35** | **1.29** | **1.25** | **1.26** | **0.5%** |

## Table A17. Renewable energy consumption by sector and source (continued)
(quadrillion Btu per year)

| Sector and source | Reference case | | | | | | | Annual growth 2011-2040 (percent) |
|---|---|---|---|---|---|---|---|---|
| | 2010 | 2011 | 2020 | 2025 | 2030 | 2035 | 2040 | |
| **Nonmarketed renewable energy[8]** | | | | | | | | |
| **Selected consumption** | | | | | | | | |
| **Residential** | **0.03** | **0.04** | **0.20** | **0.21** | **0.22** | **0.24** | **0.27** | **6.9%** |
| Solar hot water heating | 0.01 | 0.01 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 1.6% |
| Geothermal heat pumps | 0.01 | 0.01 | 0.02 | 0.02 | 0.02 | 0.03 | 0.03 | 4.3% |
| Solar photovoltaic | 0.01 | 0.02 | 0.14 | 0.15 | 0.17 | 0.18 | 0.21 | 9.1% |
| Wind | 0.00 | 0.00 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 7.0% |
| **Commercial** | **0.10** | **0.11** | **0.20** | **0.22** | **0.24** | **0.28** | **0.32** | **3.7%** |
| Solar thermal | 0.08 | 0.08 | 0.09 | 0.10 | 0.10 | 0.11 | 0.12 | 1.4% |
| Solar photovoltaic | 0.02 | 0.03 | 0.10 | 0.12 | 0.13 | 0.16 | 0.19 | 6.6% |
| Wind | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 0.01 | 7.7% |

[1]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.
[2]Includes energy for combined heat and power plants that have a non-regulatory status, and small on-site generating systems.
[3]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.
[4]Excludes motor gasoline component of E85.
[5]Renewable feedstocks for the on-site production of diesel and gasoline.
[6]Includes consumption of energy by electricity-only and combined heat and power plants that have a regulatory status. Actual heat rates used to determine fuel consumption for all renewable fuels except hydropower, geothermal, solar, and wind. Consumption at hydroelectric, geothermal, solar, and wind facilities determined by using the fossil fuel equivalent of 9,756 Btu per kilowatthour.
[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 U.S. Energy Information Administration estimates that in 2011 approximately 0.3 quadrillion Btus were consumed from a municipal waste stream containing petroleum-derived plastics and other non-renewable sources. See U.S. Energy Information Administration, *Methodology for Allocating Municipal Solid Waste to Biogenic and Non-Biogenic Energy* (Washington, DC, May 2007).
[8]Includes selected renewable energy consumption data for which the energy is not bought or sold, either directly or indirectly as an input to marketed energy. The U.S. 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 2010 and 2011 are model results and may differ slightly from official EIA data reports.
**Sources:** 2010 and 2011 ethanol: U.S. Energy Information Administration (EIA), *Annual Energy Review 2011*, DOE/EIA-0384(2011) (Washington, DC, September 2012). 2010 and 2011 electric power sector: EIA, Form EIA-860, "Annual Electric Generator Report" (preliminary). Other 2010 and 2011 values: EIA, Office of Energy Analysis. **Projections:** EIA, AEO2013 National Energy Modeling System run REF2013.D102312A.

## Table A18. Energy-related carbon dioxide emissions by sector and source
(million metric tons, unless otherwise noted)

| Sector and source | Reference case | | | | | | | Annual growth 2011-2040 (percent) |
|---|---|---|---|---|---|---|---|---|
| | 2010 | 2011 | 2020 | 2025 | 2030 | 2035 | 2040 | |
| **Residential** | | | | | | | | |
| Petroleum | 85 | 78 | 71 | 66 | 62 | 59 | 57 | -1.1% |
| Natural gas | 267 | 256 | 245 | 241 | 236 | 230 | 225 | -0.5% |
| Coal | 1 | 1 | 1 | 1 | 1 | 0 | 0 | -0.8% |
| Electricity[1] | 875 | 828 | 744 | 776 | 817 | 862 | 888 | 0.2% |
| **Total residential** | **1,228** | **1,162** | **1,061** | **1,084** | **1,117** | **1,152** | **1,170** | **0.0%** |
| **Commercial** | | | | | | | | |
| Petroleum | 51 | 49 | 47 | 46 | 45 | 45 | 44 | -0.3% |
| Natural gas | 173 | 171 | 180 | 182 | 186 | 191 | 195 | 0.5% |
| Coal | 6 | 5 | 5 | 5 | 5 | 5 | 5 | 0.0% |
| Electricity[1] | 805 | 767 | 725 | 760 | 796 | 831 | 843 | 0.3% |
| **Total commercial** | **1,034** | **992** | **957** | **992** | **1,032** | **1,071** | **1,087** | **0.3%** |
| **Industrial[2]** | | | | | | | | |
| Petroleum | 344 | 345 | 355 | 349 | 342 | 342 | 347 | 0.0% |
| Natural gas[3] | 408 | 417 | 491 | 506 | 511 | 523 | 538 | 0.9% |
| Coal | 157 | 143 | 154 | 157 | 152 | 150 | 155 | 0.3% |
| Electricity[1] | 587 | 567 | 607 | 619 | 604 | 592 | 575 | 0.0% |
| **Total industrial** | **1,496** | **1,472** | **1,606** | **1,631** | **1,608** | **1,607** | **1,615** | **0.3%** |
| **Transportation** | | | | | | | | |
| Petroleum[4] | 1,836 | 1,802 | 1,785 | 1,744 | 1,705 | 1,695 | 1,712 | -0.2% |
| Natural gas[5] | 36 | 39 | 42 | 45 | 53 | 72 | 97 | 3.2% |
| Electricity[1] | 4 | 4 | 5 | 6 | 7 | 8 | 10 | 3.3% |
| **Total transportation** | **1,876** | **1,845** | **1,831** | **1,794** | **1,766** | **1,776** | **1,819** | **-0.0%** |
| **Electric power[6]** | | | | | | | | |
| Petroleum | 33 | 25 | 13 | 14 | 14 | 14 | 14 | -2.0% |
| Natural gas | 399 | 411 | 446 | 458 | 482 | 511 | 514 | 0.8% |
| Coal | 1,828 | 1,718 | 1,610 | 1,678 | 1,717 | 1,757 | 1,775 | 0.1% |
| Other[7] | 12 | 11 | 11 | 11 | 11 | 11 | 11 | 0.0% |
| **Total electric power** | **2,271** | **2,166** | **2,081** | **2,161** | **2,224** | **2,293** | **2,315** | **0.2%** |
| **Total by fuel** | | | | | | | | |
| Petroleum[4] | 2,349 | 2,299 | 2,270 | 2,218 | 2,169 | 2,156 | 2,175 | -0.2% |
| Natural gas | 1,283 | 1,294 | 1,404 | 1,431 | 1,468 | 1,528 | 1,569 | 0.7% |
| Coal | 1,990 | 1,867 | 1,769 | 1,841 | 1,874 | 1,912 | 1,936 | 0.1% |
| Other[7] | 12 | 11 | 11 | 11 | 11 | 11 | 11 | 0.0% |
| **Total** | **5,634** | **5,471** | **5,455** | **5,501** | **5,523** | **5,607** | **5,691** | **0.1%** |
| **Carbon dioxide emissions (tons per person)** | **18.2** | **17.5** | **16.0** | **15.4** | **14.8** | **14.4** | **14.1** | **-0.8%** |

[1]Emissions from the electric power sector are distributed to the end-use sectors.
[2]Includes combined heat and power plants that have a non-regulatory status, and small on-site generating systems.
[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 2009, international bunker fuels accounted for 90 to 126 million metric tons annually.
[5]Includes pipeline fuel natural gas and natural gas used as vehicle fuel.
[6]Includes electricity-only and combined heat and power plants that have a regulatory status.
[7]Includes emissions from geothermal power and nonbiogenic emissions from municipal waste.
Note: By convention, the direct emissions from biogenic energy sources are excluded from energy-related carbon dioxide emissions. The release of carbon from these sources 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. If, however, increased use of biomass energy results in a decline in terrestrial carbon stocks, a net positive release of carbon may occur. See "Energy-Related Carbon Dioxide Emissions by End Use" for the emissions from biogenic energy sources as an indication of the potential net release of carbon dioxide in the absence of offsetting sequestration. Totals may not equal sum of components due to independent rounding. Data for 2010 and 2011 are model results and may differ slightly from official EIA data reports.
**Sources:** 2010 and 2011 emissions and emission factors: U.S. Energy Information Administration (EIA), *Annual Energy Review 2011*, DOE/EIA-0384(2011) (Washington, DC, September 2012). 2010 emissions: EIA, *Monthly Energy Review*, DOE/EIA-0035(2011/10) (Washington, DC, October 2011). 2011 emissions and emission factors: EIA, *Monthly Energy Review*, DOE/EIA-0035(2012/08) (Washington, DC, August 2012). **Projections:** EIA, AEO2013 National Energy Modeling System run REF2013.D102312A.

## Table A19. Energy-related carbon dioxide emissions by end use
(million metric tons)

| Sector and end use | Reference case 2010 | 2011 | 2020 | 2025 | 2030 | 2035 | 2040 | Annual growth 2011-2040 (percent) |
|---|---|---|---|---|---|---|---|---|
| **Residential** | | | | | | | | |
| Space heating | 285.69 | 274.74 | 255.95 | 247.75 | 241.43 | 234.50 | 224.88 | -0.7% |
| Space cooling | 162.29 | 158.49 | 146.49 | 159.05 | 173.02 | 187.28 | 194.44 | 0.7% |
| Water heating | 159.50 | 156.30 | 155.23 | 157.27 | 156.47 | 154.26 | 153.31 | -0.1% |
| Refrigeration | 66.67 | 63.92 | 58.33 | 59.80 | 62.44 | 65.23 | 66.18 | 0.1% |
| Cooking | 32.50 | 31.97 | 32.51 | 33.82 | 35.31 | 36.76 | 37.50 | 0.6% |
| Clothes dryers | 37.70 | 36.32 | 36.43 | 38.02 | 39.80 | 41.64 | 42.10 | 0.5% |
| Freezers | 14.58 | 14.07 | 12.72 | 12.69 | 12.67 | 12.72 | 12.53 | -0.4% |
| Lighting | 115.65 | 108.10 | 69.37 | 61.08 | 57.56 | 56.74 | 55.83 | -2.3% |
| Clothes washers[1] | 5.81 | 5.54 | 4.19 | 3.82 | 3.62 | 3.70 | 3.76 | -1.3% |
| Dishwashers[1] | 18.27 | 17.62 | 15.99 | 16.02 | 16.94 | 18.21 | 18.93 | 0.2% |
| Televisions and related equipment[2] | 56.31 | 54.02 | 53.97 | 57.27 | 60.97 | 64.92 | 66.79 | 0.7% |
| Computers and related equipment[3] | 28.12 | 26.74 | 20.20 | 18.98 | 18.84 | 18.91 | 18.42 | -1.3% |
| Furnace fans and boiler circulation pumps | 23.83 | 22.95 | 21.43 | 21.52 | 21.61 | 21.64 | 20.96 | -0.3% |
| Other uses | 206.69 | 192.29 | 178.57 | 197.45 | 216.66 | 235.95 | 254.42 | 1.0% |
| Discrepancy[4] | 13.90 | -0.72 | -0.66 | -0.60 | -0.55 | -0.49 | -0.45 | -1.6% |
| **Total residential** | **1,227.53** | **1,162.33** | **1,060.73** | **1,083.95** | **1,116.78** | **1,151.98** | **1,169.60** | **0.0%** |
| **Commercial** | | | | | | | | |
| Space heating[5] | 129.14 | 125.16 | 120.43 | 116.90 | 113.92 | 110.05 | 104.21 | -0.6% |
| Space cooling[5] | 100.98 | 99.43 | 83.32 | 85.01 | 86.89 | 89.61 | 89.71 | -0.4% |
| Water heating[5] | 41.26 | 41.42 | 42.51 | 43.21 | 43.77 | 43.83 | 42.91 | 0.1% |
| Ventilation | 86.72 | 84.34 | 82.87 | 85.39 | 87.72 | 89.24 | 87.81 | 0.1% |
| Cooking | 13.53 | 13.60 | 14.12 | 14.39 | 14.79 | 15.11 | 15.10 | 0.4% |
| Lighting | 170.14 | 159.77 | 137.50 | 137.62 | 137.71 | 134.23 | 127.51 | -0.8% |
| Refrigeration | 68.65 | 64.87 | 54.38 | 54.23 | 55.14 | 56.54 | 56.50 | -0.5% |
| Office equipment (PC) | 37.41 | 34.69 | 29.46 | 29.97 | 31.21 | 31.99 | 31.91 | -0.3% |
| Office equipment (non-PC) | 40.15 | 38.30 | 37.97 | 40.72 | 43.33 | 45.18 | 45.13 | 0.6% |
| Other uses[6] | 346.27 | 330.16 | 354.48 | 384.84 | 417.63 | 455.24 | 486.52 | 1.3% |
| **Total commercial** | **1,034.26** | **991.74** | **957.03** | **992.28** | **1,032.11** | **1,071.02** | **1,087.30** | **0.3%** |
| **Industrial[7]** | | | | | | | | |
| Manufacturing | | | | | | | | |
| Refining | 261.87 | 256.26 | 245.90 | 249.79 | 254.75 | 261.90 | 270.14 | 0.2% |
| Food products | 99.97 | 99.13 | 103.10 | 107.71 | 110.82 | 113.57 | 115.35 | 0.5% |
| Paper products | 77.52 | 71.94 | 69.45 | 70.41 | 70.83 | 71.37 | 72.28 | 0.0% |
| Bulk chemicals | 259.35 | 246.50 | 257.53 | 256.29 | 241.10 | 227.51 | 214.99 | -0.5% |
| Glass | 19.21 | 18.88 | 22.35 | 24.03 | 24.70 | 24.88 | 25.48 | 1.0% |
| Cement manufacturing | 26.02 | 26.85 | 39.05 | 39.26 | 39.72 | 41.88 | 44.97 | 1.8% |
| Iron and steel | 118.17 | 123.07 | 147.83 | 143.48 | 125.21 | 111.79 | 106.29 | -0.5% |
| Aluminum | 44.84 | 46.19 | 56.02 | 57.93 | 50.38 | 43.21 | 34.05 | -1.0% |
| Fabricated metal products | 37.67 | 39.72 | 39.70 | 39.25 | 37.79 | 37.42 | 37.35 | -0.2% |
| Machinery | 23.70 | 25.44 | 28.77 | 29.63 | 29.82 | 30.32 | 31.47 | 0.7% |
| Computers and electronics | 31.55 | 29.96 | 32.14 | 33.80 | 34.77 | 36.31 | 37.13 | 0.7% |
| Transportation equipment | 47.09 | 50.85 | 61.43 | 65.04 | 68.29 | 72.17 | 73.71 | 1.3% |
| Electrical equipment | 8.02 | 7.98 | 8.86 | 9.07 | 9.17 | 9.73 | 10.47 | 0.9% |
| Wood products | 17.11 | 16.80 | 21.91 | 22.06 | 21.26 | 20.68 | 19.87 | 0.6% |
| Plastics | 39.27 | 40.00 | 38.28 | 38.25 | 38.44 | 37.97 | 36.39 | -0.3% |
| Balance of manufacturing | 141.86 | 139.34 | 146.13 | 155.71 | 162.73 | 171.45 | 180.33 | 0.9% |
| Total manufacturing | 1,253.22 | 1,238.92 | 1,318.46 | 1,341.71 | 1,319.77 | 1,312.15 | 1,310.27 | 0.2% |
| Nonmanufacturing | | | | | | | | |
| Agriculture | 72.17 | 68.36 | 68.84 | 68.02 | 67.75 | 67.61 | 67.44 | -0.0% |
| Construction | 69.98 | 66.71 | 92.16 | 92.34 | 93.37 | 95.63 | 99.14 | 1.4% |
| Mining | 55.72 | 55.52 | 57.67 | 55.57 | 53.64 | 53.07 | 51.75 | -0.2% |
| Total nonmanufacturing | 197.87 | 190.59 | 218.67 | 215.93 | 214.76 | 216.31 | 218.33 | 0.5% |
| Discrepancy[4] | 45.06 | 42.57 | 68.69 | 73.07 | 73.73 | 78.98 | 86.73 | 2.5% |
| **Total industrial** | **1,496.14** | **1,472.08** | **1,605.81** | **1,630.71** | **1,608.26** | **1,607.44** | **1,615.33** | **0.3%** |

## Table A19. Energy-related carbon dioxide emissions by end use (continued)
(million metric tons)

| Sector and end use | Reference case 2010 | 2011 | 2020 | 2025 | 2030 | 2035 | 2040 | Annual growth 2011-2040 (percent) |
|---|---|---|---|---|---|---|---|---|
| **Transportation** | | | | | | | | |
| Light-duty vehicles | 1,059.53 | 1,036.67 | 929.21 | 870.47 | 824.70 | 804.78 | 804.29 | -0.9% |
| Commercial light trucks[8] | 38.08 | 37.35 | 37.93 | 36.83 | 35.97 | 36.60 | 38.70 | 0.1% |
| Bus transportation | 17.81 | 17.20 | 17.55 | 17.79 | 17.96 | 18.08 | 18.27 | 0.2% |
| Freight trucks | 350.67 | 352.73 | 430.98 | 442.74 | 450.92 | 471.42 | 502.86 | 1.2% |
| Rail, passenger | 5.63 | 5.54 | 5.74 | 6.04 | 6.33 | 6.66 | 6.81 | 0.7% |
| Rail, freight | 33.43 | 32.40 | 35.40 | 37.59 | 38.96 | 39.97 | 40.76 | 0.8% |
| Shipping, domestic | 15.77 | 15.75 | 18.43 | 17.91 | 17.12 | 17.12 | 17.18 | 0.3% |
| Shipping, international | 66.38 | 62.27 | 63.27 | 63.88 | 64.50 | 65.06 | 65.55 | 0.2% |
| Recreational boats | 16.94 | 16.30 | 17.08 | 17.69 | 18.28 | 18.78 | 19.13 | 0.6% |
| Air | 178.28 | 174.72 | 187.90 | 193.68 | 197.37 | 199.69 | 202.49 | 0.5% |
| Military use | 54.58 | 52.66 | 45.19 | 46.04 | 48.49 | 51.34 | 54.59 | 0.1% |
| Lubricants | 5.24 | 4.95 | 4.50 | 4.56 | 4.62 | 4.69 | 4.78 | -0.1% |
| Pipeline fuel | 36.30 | 37.11 | 37.76 | 38.73 | 39.33 | 40.34 | 41.19 | 0.4% |
| Discrepancy[4] | -2.97 | -1.06 | 0.04 | 0.54 | 1.10 | 1.69 | 2.26 | - - |
| **Total transportation** | **1,875.67** | **1,844.58** | **1,830.99** | **1,794.48** | **1,765.65** | **1,776.24** | **1,818.85** | **-0.0%** |
| | | | | | | | | |
| **Biogenic energy combustion[9]** | | | | | | | | |
| Biomass | 189.40 | 194.39 | 254.82 | 282.24 | 290.63 | 305.61 | 332.19 | 1.9% |
| Electric power sector | 18.52 | 17.81 | 60.15 | 74.35 | 71.05 | 72.79 | 82.99 | 5.4% |
| Other sectors | 170.88 | 176.57 | 194.68 | 207.89 | 219.58 | 232.82 | 249.20 | 1.2% |
| Biogenic waste | 4.37 | 4.90 | 6.22 | 6.22 | 6.23 | 6.23 | 6.23 | 0.8% |
| Biofuels heat and coproducts | 80.21 | 63.03 | 76.56 | 76.49 | 79.37 | 91.26 | 128.24 | 2.5% |
| Ethanol | 74.92 | 74.85 | 95.83 | 92.45 | 88.48 | 85.70 | 86.13 | 0.5% |
| Biodiesel | 2.42 | 8.63 | 11.55 | 11.68 | 11.66 | 11.66 | 11.68 | 1.0% |
| Liquids from biomass | 0.00 | 0.00 | 1.47 | 3.15 | 7.35 | 20.07 | 55.90 | - - |
| Renewable diesel and gasoline | 0.50 | 0.20 | 1.81 | 1.82 | 1.82 | 1.82 | 1.81 | 7.9% |
| **Total** | **351.81** | **346.01** | **448.26** | **474.05** | **485.54** | **522.35** | **622.19** | **2.0%** |

[1]Does not include water heating portion of load.
[2]Includes televisions, set-top boxes, and video game consoles.
[3]Includes desktop and laptop computers, monitors, printers, speakers, networking equipment, and uninterruptible power supplies.
[4]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.
[5]Includes emissions related to fuel consumption for district services.
[6] Includes (but is not limited to) miscellaneous uses such as transformers, medical imaging and other medical equipment, elevators, escalators, off-road electric vehicles, laboratory fume hoods, laundry equipment, coffee brewers, water services, 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, kerosene, and marketed renewable fuels (biomass).
[7]Includes combined heat and power plants that have a non-regulatory status, and small on-site generating systems.
[8]Commercial trucks 8,501 to 10,000 pounds gross vehicle weight rating.
[9]By convention, the direct emissions from biogenic energy sources are excluded from energy-related carbon dioxide emissions. The release of carbon from these sources 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. If, however, increased use of biomass energy results in a decline in terrestrial carbon stocks, a net positive release of carbon may occur. Accordingly, the emissions from biogenic energy sources are reported here as an indication of the potential net release of carbon dioxide in the absence of offsetting sequestration.
- - = Not applicable.
Note: Totals may not equal sum of components due to independent rounding. Data for 2010 and 2011 are model results and may differ slightly from official EIA data reports.
**Sources:** 2010 and 2011 emissions and emission factors: U.S. Energy Information Administration (EIA), *Annual Energy Review 2011*, DOE/EIA-0384(2011) (Washington, DC, September 2012). 2010 emissions: EIA, *Monthly Energy Review*, DOE/EIA-0035(2011/10) (Washington, DC, October 2011). 2011 emissions and emission factors: EIA, *Monthly Energy Review*, DOE/EIA-0035(2012/08) (Washington, DC, August 2012). **Projections:** EIA, AEO2013 National Energy Modeling System run REF2013.D102312A.

## Table A20. Macroeconomic indicators
(billion 2005 chain-weighted dollars, unless otherwise noted)

| Indicators | Reference case | | | | | | | Annual growth 2011-2040 (percent) |
|---|---|---|---|---|---|---|---|---|
| | 2010 | 2011 | 2020 | 2025 | 2030 | 2035 | 2040 | |
| **Real gross domestic product** | **13,063** | **13,299** | **16,859** | **18,985** | **21,355** | **24,095** | **27,277** | **2.5%** |
| **Components of real gross domestic product** | | | | | | | | |
| Real consumption | 9,196 | 9,429 | 11,528 | 12,792 | 14,243 | 15,941 | 17,917 | 2.2% |
| Real investment | 1,658 | 1,744 | 2,909 | 3,363 | 3,914 | 4,582 | 5,409 | 4.0% |
| Real government spending | 2,606 | 2,524 | 2,446 | 2,529 | 2,659 | 2,803 | 2,980 | 0.6% |
| Real exports | 1,666 | 1,777 | 3,016 | 4,026 | 5,214 | 6,658 | 8,357 | 5.5% |
| Real imports | 2,085 | 2,185 | 2,927 | 3,515 | 4,311 | 5,308 | 6,518 | 3.8% |
| **Energy intensity (thousand Btu per 2005 dollar of GDP)** | | | | | | | | |
| Delivered energy | 5.47 | 5.34 | 4.39 | 3.92 | 3.48 | 3.13 | 2.85 | -2.1% |
| Total energy | 7.53 | 7.35 | 5.99 | 5.39 | 4.81 | 4.33 | 3.95 | -2.1% |
| **Price indices** | | | | | | | | |
| GDP chain-type price index (2005=1.000) | 1.110 | 1.134 | 1.307 | 1.429 | 1.564 | 1.713 | 1.871 | 1.7% |
| Consumer price index (1982-4=1.00) | | | | | | | | |
| All-urban | 2.18 | 2.25 | 2.66 | 2.94 | 3.27 | 3.63 | 4.04 | 2.0% |
| Energy commodities and services | 2.12 | 2.44 | 2.70 | 3.09 | 3.53 | 4.11 | 4.86 | 2.4% |
| Wholesale price index (1982=1.00) | | | | | | | | |
| All commodities | 1.85 | 2.01 | 2.22 | 2.40 | 2.59 | 2.82 | 3.10 | 1.5% |
| Fuel and power | 1.86 | 2.16 | 2.48 | 2.91 | 3.38 | 4.02 | 4.90 | 2.9% |
| Metals and metal products | 2.08 | 2.26 | 2.52 | 2.66 | 2.83 | 2.99 | 3.16 | 1.2% |
| Industrial commodities excluding energy | 1.83 | 1.93 | 2.12 | 2.23 | 2.34 | 2.45 | 2.57 | 1.0% |
| **Interest rates (percent, nominal)** | | | | | | | | |
| Federal funds rate | 0.17 | 0.10 | 4.04 | 4.09 | 3.97 | 3.84 | 3.74 | - - |
| 10-year treasury note | 3.21 | 2.79 | 4.88 | 4.97 | 4.95 | 4.91 | 4.86 | - - |
| AA utility bond rate | 5.23 | 4.78 | 6.91 | 7.10 | 7.21 | 7.35 | 7.39 | - - |
| **Value of shipments (billion 2005 dollars)** | | | | | | | | |
| Service sectors | 20,771 | 21,168 | 26,492 | 29,715 | 32,624 | 35,511 | 38,529 | 2.1% |
| Total industrial | 5,842 | 6,019 | 7,894 | 8,548 | 9,087 | 9,779 | 10,616 | 2.0% |
| Agriculture, mining, and construction | 1,585 | 1,582 | 2,211 | 2,295 | 2,375 | 2,494 | 2,644 | 1.8% |
| Manufacturing | 4,257 | 4,438 | 5,683 | 6,253 | 6,712 | 7,285 | 7,972 | 2.0% |
| Energy-intensive | 1,592 | 1,615 | 1,893 | 1,993 | 2,027 | 2,077 | 2,144 | 1.0% |
| Non-energy-intensive | 2,665 | 2,823 | 3,790 | 4,261 | 4,685 | 5,208 | 5,828 | 2.5% |
| **Total shipments** | **26,613** | **27,187** | **34,385** | **38,264** | **41,711** | **45,289** | **49,145** | **2.1%** |
| **Population and employment (millions)** | | | | | | | | |
| Population, with armed forces overseas | 310.1 | 312.4 | 340.5 | 356.5 | 372.4 | 388.3 | 404.4 | 0.9% |
| Population, aged 16 and over | 244.6 | 247.0 | 269.5 | 282.8 | 296.3 | 309.8 | 322.9 | 0.9% |
| Population, over age 65 | 40.6 | 41.6 | 55.4 | 64.5 | 72.7 | 78.1 | 81.8 | 2.4% |
| Employment, nonfarm | 129.8 | 131.3 | 149.2 | 153.7 | 160.8 | 166.7 | 174.0 | 1.0% |
| Employment, manufacturing | 11.5 | 11.7 | 12.4 | 12.2 | 11.2 | 10.5 | 9.9 | -0.6% |
| **Key labor indicators** | | | | | | | | |
| Labor force (millions) | 153.9 | 153.6 | 164.7 | 169.3 | 174.9 | 182.3 | 190.7 | 0.7% |
| Nonfarm labor productivity (1992=1.00) | 1.09 | 1.10 | 1.25 | 1.39 | 1.54 | 1.70 | 1.88 | 1.9% |
| Unemployment rate (percent) | 9.62 | 8.95 | 5.49 | 5.27 | 5.32 | 5.33 | 5.24 | - - |
| **Key indicators for energy demand** | | | | | | | | |
| Real disposable personal income | 10,017 | 10,150 | 12,655 | 14,259 | 15,948 | 17,752 | 19,785 | 2.3% |
| Housing starts (millions) | 0.64 | 0.66 | 1.89 | 1.90 | 1.89 | 1.89 | 1.89 | 3.7% |
| Commercial floorspace (billion square feet) | 81.1 | 81.7 | 89.1 | 93.9 | 98.1 | 103.0 | 108.8 | 1.0% |
| Unit sales of light-duty vehicles (millions) | 11.55 | 12.73 | 16.85 | 17.16 | 17.74 | 18.20 | 19.21 | 1.4% |

GDP = Gross domestic product.
Btu = British thermal unit.
- - = Not applicable.
**Sources:** 2010 and 2011: IHS Global Insight, Global Insight Industry and Employment models, August 2012. **Projections:** U.S. Energy Information Administration, AEO2013 National Energy Modeling System run REF2013.D102312A.

**Table A21. International liquids supply and disposition summary**
(million barrels per day, unless otherwise noted)

| Supply and disposition | Reference case | | | | | | | Annual growth 2011-2040 (percent) |
|---|---|---|---|---|---|---|---|---|
| | 2010 | 2011 | 2020 | 2025 | 2030 | 2035 | 2040 | |
| **Crude oil spot prices** | | | | | | | | |
| **(2011 dollars per barrel)** | | | | | | | | |
| Brent | 81.31 | 111.26 | 105.57 | 117.36 | 130.47 | 145.41 | 162.68 | 1.3% |
| West Texas Intermediate | 81.08 | 94.86 | 103.57 | 115.36 | 128.47 | 143.41 | 160.68 | 1.8% |
| **(nominal dollars per barrel)** | | | | | | | | |
| Brent | 79.61 | 111.26 | 121.73 | 147.90 | 180.04 | 219.73 | 268.50 | 3.1% |
| West Texas Intermediate | 79.39 | 94.86 | 119.43 | 145.38 | 177.28 | 216.70 | 265.20 | 3.6% |
| **Liquids consumption[1]** | | | | | | | | |
| OECD | | | | | | | | |
| United States (50 states) | 18.90 | 18.68 | 19.49 | 19.16 | 18.72 | 18.55 | 18.64 | 0.0% |
| United States territories | 0.25 | 0.28 | 0.32 | 0.34 | 0.36 | 0.36 | 0.37 | 1.0% |
| Canada | 2.22 | 2.29 | 2.21 | 2.18 | 2.18 | 2.21 | 2.30 | 0.0% |
| Mexico and Chile | 2.40 | 2.41 | 2.66 | 2.83 | 3.05 | 3.26 | 3.47 | 1.3% |
| OECD Europe[2] | 14.80 | 14.28 | 13.81 | 13.85 | 13.96 | 14.10 | 14.21 | 0.0% |
| Japan | 4.37 | 4.46 | 4.41 | 4.33 | 4.25 | 4.15 | 3.94 | -0.4% |
| South Korea | 2.25 | 2.32 | 2.56 | 2.61 | 2.66 | 2.69 | 2.74 | 0.6% |
| Australia and New Zealand | 1.11 | 1.12 | 1.19 | 1.19 | 1.22 | 1.25 | 1.30 | 0.5% |
| **Total OECD** | **46.28** | **45.83** | **46.63** | **46.48** | **46.40** | **46.57** | **46.96** | **0.1%** |
| Non-OECD | | | | | | | | |
| Russia | 2.98 | 3.13 | 3.53 | 3.65 | 3.83 | 3.95 | 3.95 | 0.8% |
| Other Europe and Eurasia[3] | 1.82 | 2.27 | 2.38 | 2.44 | 2.63 | 2.84 | 3.07 | 1.0% |
| China | 9.33 | 9.85 | 13.29 | 14.71 | 15.58 | 16.64 | 17.59 | 2.0% |
| India | 3.26 | 3.28 | 4.27 | 4.92 | 5.61 | 6.25 | 6.81 | 2.6% |
| Other Asia[4] | 7.14 | 6.87 | 7.88 | 8.53 | 9.30 | 10.19 | 11.25 | 1.7% |
| Middle East | 6.74 | 7.51 | 8.40 | 8.57 | 8.92 | 9.35 | 9.78 | 0.9% |
| Africa | 3.37 | 3.31 | 3.63 | 3.82 | 4.05 | 4.32 | 4.49 | 1.1% |
| Brazil | 2.62 | 2.59 | 3.01 | 3.12 | 3.37 | 3.62 | 4.00 | 1.5% |
| Other Central and South America | 3.21 | 3.37 | 3.42 | 3.52 | 3.71 | 3.92 | 4.02 | 0.6% |
| **Total non-OECD** | **40.46** | **42.18** | **49.82** | **53.27** | **57.00** | **61.07** | **64.97** | **1.5%** |
| **Total liquids consumption** | **86.75** | **88.01** | **96.45** | **99.75** | **103.41** | **107.64** | **111.93** | **0.8%** |
| **Liquids production** | | | | | | | | |
| OPEC[5] | | | | | | | | |
| Middle East | 23.77 | 25.40 | 26.65 | 27.91 | 29.88 | 32.63 | 35.09 | 1.1% |
| North Africa | 3.76 | 2.39 | 3.27 | 3.27 | 3.48 | 3.77 | 3.96 | 1.8% |
| West Africa | 4.45 | 4.31 | 5.33 | 5.47 | 5.61 | 5.75 | 5.89 | 1.1% |
| South America | 2.88 | 2.99 | 3.09 | 3.05 | 3.01 | 3.06 | 3.20 | 0.2% |
| **Total OPEC** | **34.85** | **35.08** | **38.34** | **39.69** | **41.98** | **45.20** | **48.13** | **1.1%** |
| Non-OPEC | | | | | | | | |
| OECD | | | | | | | | |
| United States (50 states) | 9.44 | 10.11 | 12.74 | 12.10 | 11.42 | 11.52 | 11.67 | 0.5% |
| Canada | 3.58 | 3.66 | 5.09 | 5.60 | 5.91 | 6.09 | 6.14 | 1.8% |
| Mexico and Chile | 3.01 | 2.99 | 1.96 | 1.84 | 1.98 | 2.04 | 2.12 | -1.2% |
| OECD Europe[2] | 4.58 | 4.19 | 3.38 | 3.08 | 2.84 | 2.93 | 3.36 | -0.8% |
| Japan | 0.18 | 0.18 | 0.17 | 0.18 | 0.18 | 0.19 | 0.19 | 0.2% |
| Australia and New Zealand | 0.66 | 0.58 | 0.54 | 0.53 | 0.56 | 0.78 | 0.87 | 1.4% |
| **Total OECD** | **21.45** | **21.71** | **23.88** | **23.33** | **22.90** | **23.54** | **24.35** | **0.4%** |
| Non-OECD | | | | | | | | |
| Russia | 10.14 | 10.23 | 10.75 | 10.95 | 11.43 | 11.94 | 11.48 | 0.4% |
| Other Europe and Eurasia[3] | 3.24 | 3.26 | 4.20 | 4.85 | 4.85 | 4.83 | 5.24 | 1.6% |
| China | 4.34 | 4.34 | 4.59 | 5.02 | 5.50 | 5.54 | 5.42 | 0.8% |
| Other Asia[4] | 3.82 | 3.74 | 3.55 | 3.34 | 3.09 | 2.81 | 2.87 | -0.9% |
| Middle East | 1.57 | 1.43 | 1.23 | 1.22 | 1.09 | 0.91 | 0.89 | -1.6% |
| Africa | 2.68 | 2.68 | 3.08 | 3.14 | 3.10 | 2.95 | 3.18 | 0.6% |
| Brazil | 2.52 | 2.53 | 4.35 | 5.63 | 6.96 | 7.43 | 7.61 | 3.9% |
| Other Central and South America | 2.08 | 2.17 | 2.40 | 2.51 | 2.46 | 2.43 | 2.69 | 0.7% |
| **Total non-OECD** | **30.39** | **30.39** | **34.15** | **36.65** | **38.47** | **38.84** | **39.37** | **0.9%** |
| **Total liquids production** | **86.70** | **87.18** | **96.38** | **99.68** | **103.35** | **107.58** | **111.85** | **0.9%** |
| OPEC liquids market share (percent) | 40.2 | 40.2 | 39.8 | 39.8 | 40.6 | 42.0 | 43.0 | - - |

## Table A21. International liquids supply and disposition summary (continued)
(million barrels per day, unless otherwise noted)

| Supply and disposition | Reference case | | | | | | | Annual growth 2011-2040 (percent) |
|---|---|---|---|---|---|---|---|---|
| | 2010 | 2011 | 2020 | 2025 | 2030 | 2035 | 2040 | |
| **Selected world liquids production subtotals:** | | | | | | | | |
| Petroleum[6] | | | | | | | | |
| Crude oil and equivalents[7] | 74.11 | 74.08 | 80.28 | 82.51 | 85.26 | 87.59 | 90.90 | 0.7% |
| Tight oil | 0.82 | 1.27 | 3.83 | 4.52 | 4.91 | 5.54 | 6.10 | 5.6% |
| Bitumen[8] | 1.65 | 1.74 | 3.00 | 3.52 | 3.95 | 4.21 | 4.26 | 3.1% |
| Natural gas plant liquids | 8.53 | 8.66 | 10.88 | 11.52 | 11.75 | 12.40 | 12.88 | 1.4% |
| Refinery processing gain[9] | 2.27 | 2.28 | 2.20 | 2.31 | 2.50 | 2.69 | 2.82 | 0.7% |
| Liquids from renewable sources[10] | 1.31 | 1.33 | 2.08 | 2.29 | 2.49 | 2.67 | 2.93 | 2.8% |
| Liquids from coal[11] | 0.17 | 0.18 | 0.40 | 0.68 | 0.95 | 1.17 | 1.19 | 6.7% |
| Liquids from natural gas[12] | 0.07 | 0.12 | 0.39 | 0.45 | 0.48 | 0.51 | 0.55 | 5.4% |
| Liquids from kerogen[13] | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.6% |
| **Petroleum production[6]** | | | | | | | | |
| OPEC[5] | | | | | | | | |
| Middle East | 23.76 | 25.34 | 26.44 | 27.66 | 29.64 | 32.38 | 34.84 | 1.1% |
| North Africa | 3.76 | 2.39 | 3.27 | 3.27 | 3.48 | 3.77 | 3.96 | 1.8% |
| West Africa | 4.45 | 4.31 | 5.30 | 5.44 | 5.58 | 5.72 | 5.86 | 1.1% |
| South America | 2.88 | 2.99 | 3.09 | 3.05 | 3.01 | 3.06 | 3.20 | 0.2% |
| **Total OPEC** | **34.85** | **35.03** | **38.10** | **39.42** | **41.71** | **44.93** | **47.86** | **1.1%** |
| Non-OPEC | | | | | | | | |
| OECD | | | | | | | | |
| United States (50 states) | 8.66 | 9.25 | 11.64 | 10.95 | 10.21 | 10.20 | 10.08 | 0.3% |
| Canada | 3.56 | 3.64 | 5.07 | 5.57 | 5.87 | 6.05 | 6.10 | 1.8% |
| Mexico and Chile | 3.01 | 2.99 | 1.96 | 1.84 | 1.98 | 2.04 | 2.12 | -1.2% |
| OECD Europe[2] | 4.36 | 3.98 | 3.16 | 2.85 | 2.60 | 2.67 | 3.09 | -0.9% |
| Japan | 0.17 | 0.17 | 0.16 | 0.17 | 0.18 | 0.18 | 0.18 | 0.1% |
| Australia and New Zealand | 0.66 | 0.57 | 0.53 | 0.52 | 0.55 | 0.77 | 0.86 | 1.4% |
| **Total OECD** | **20.43** | **20.60** | **22.52** | **21.90** | **21.39** | **21.90** | **22.43** | **0.3%** |
| Non-OECD | | | | | | | | |
| Russia | 10.14 | 10.23 | 10.75 | 10.94 | 11.42 | 11.94 | 11.47 | 0.4% |
| Other Europe and Eurasia[3] | 3.24 | 3.25 | 4.19 | 4.84 | 4.84 | 4.82 | 5.23 | 1.7% |
| China | 4.30 | 4.30 | 4.44 | 4.65 | 4.83 | 4.64 | 4.52 | 0.2% |
| Other Asia[4] | 3.76 | 3.67 | 3.42 | 3.13 | 2.88 | 2.59 | 2.65 | -1.1% |
| Middle East | 1.57 | 1.43 | 1.23 | 1.22 | 1.09 | 0.91 | 0.89 | -1.6% |
| Africa | 2.46 | 2.47 | 2.75 | 2.80 | 2.74 | 2.60 | 2.82 | 0.5% |
| Brazil | 2.19 | 2.25 | 3.57 | 4.70 | 5.92 | 6.30 | 6.48 | 3.7% |
| Other Central and South America | 2.01 | 2.09 | 2.33 | 2.43 | 2.38 | 2.34 | 2.60 | 0.8% |
| **Total non-OECD** | **29.68** | **29.69** | **32.69** | **34.73** | **36.11** | **36.15** | **36.66** | **0.7%** |
| **Total petroleum production** | **84.96** | **85.31** | **93.32** | **96.05** | **99.20** | **102.99** | **106.96** | **0.8%** |
| OPEC petroleum market share (percent) | 41.0 | 41.1 | 40.8 | 41.0 | 42.0 | 43.6 | 44.7 | - - |

[1]Includes both OPEC and non-OPEC consumers in the regional breakdown.
[2]OECD Europe = Organization for Economic Cooperation and Development - Austria, Belgium, Czech Republic, Denmark, Estonia, Finland, France, Germany, Greece, Hungary, Iceland, Ireland, Italy, Luxembourg, the Netherlands, Norway, Poland, Portugal, Slovakia, Slovenia, Spain, Sweden, Switzerland, Turkey, and the United Kingdom.
[3]Other Europe and Eurasia = Albania, Armenia, Azerbaijan, Belarus, Bosnia and Herzegovina, Bulgaria, Croatia, Georgia, Kazakhstan, Kyrgyzstan, Latvia, Lithuania, Macedonia, Malta, Moldova, Montenegro, Romania, Serbia, Tajikistan, Turkmenistan, Ukraine, and Uzbekistan.
[4]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.
[5]OPEC = Organization of Petroleum Exporting Countries - Algeria, Angola, Ecuador, Iran, Iraq, Kuwait, Libya, Nigeria, Qatar, Saudi Arabia, the United Arab Emirates, and Venezuela.
[6]Includes production of crude oil (including lease condensate, tight oil (shale oil), extra-heavy oil, and bitumen (oil sands)), natural gas plant liquids, refinery gains, and other hydrogen and hydrocarbons for refinery feedstocks.
[7]Includes crude oil, lease condensate, tight oil (shale oil), extra-heavy oil, and bitumen (oil sands).
[8]Includes diluted and upgraded/synthetic bitumen (syncrude).
[9]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.
[10]Includes liquids produced from energy crops.
[11]Includes liquids converted from coal via the Fischer-Tropsch coal-to-liquids process.
[12]Includes liquids converted from natural gas via the Fischer-Tropsch natural-gas-to-liquids process.
[13]Includes liquids produced from kerogen (oil shale, not to be confused with tight oil (shale oil)).
- - = Not applicable.
Note: Ethanol is represented in motor gasoline equivalent barrels. Totals may not equal sum of components due to independent rounding. Data for 2010 and 2011 are model results and may differ slightly from official EIA data reports.
**Sources:** 2010 and 2011 crude oil spot prices: Thomson Reuters. 2010 quantities derived from: Energy Information Administration (EIA), International Energy Statistics database as of October 2012. **2011 quantities and projections:** EIA, AEO2013 National Energy Modeling System run REF2013.D102312A 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 | 2011 | Projections | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | | 2020 | | | 2030 | | | 2040 | | |
| | | 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 | 12.16 | 15.95 | 15.95 | 15.99 | 12.93 | 13.47 | 13.79 | 12.69 | 13.12 | 13.37 |
| Natural gas plant liquids | 2.88 | 4.10 | 4.14 | 4.20 | 3.80 | 3.85 | 3.92 | 3.86 | 3.89 | 3.95 |
| Dry natural gas | 23.51 | 26.58 | 27.19 | 27.80 | 29.33 | 30.44 | 31.92 | 32.46 | 33.87 | 35.32 |
| Coal[1] | 22.21 | 20.30 | 21.74 | 22.90 | 21.61 | 23.25 | 24.28 | 22.01 | 23.54 | 24.64 |
| Nuclear / uranium[2] | 8.26 | 9.16 | 9.25 | 9.25 | 9.41 | 9.49 | 9.60 | 8.91 | 9.44 | 11.47 |
| Hydropower | 3.17 | 2.81 | 2.83 | 2.84 | 2.84 | 2.87 | 2.90 | 2.90 | 2.92 | 2.95 |
| Biomass[3] | 4.05 | 4.77 | 5.00 | 5.06 | 5.09 | 5.42 | 5.60 | 5.95 | 6.96 | 7.48 |
| Other renewable energy[4] | 1.58 | 2.19 | 2.22 | 2.51 | 2.36 | 2.50 | 3.14 | 2.81 | 3.84 | 5.86 |
| Other[5] | 1.20 | 0.80 | 0.83 | 0.86 | 0.82 | 0.88 | 0.93 | 0.82 | 0.89 | 0.96 |
| **Total** | **79.02** | **86.65** | **89.16** | **91.40** | **88.18** | **92.18** | **96.08** | **92.41** | **98.46** | **105.99** |
| **Imports** | | | | | | | | | | |
| Crude oil | 19.46 | 13.71 | 15.02 | 16.14 | 14.38 | 16.33 | 18.27 | 14.17 | 16.89 | 19.70 |
| Liquid fuels and other petroleum[6] | 5.24 | 5.44 | 5.55 | 5.60 | 5.19 | 5.33 | 5.59 | 4.81 | 4.82 | 5.70 |
| Natural gas[7] | 3.54 | 2.46 | 2.58 | 2.70 | 2.42 | 2.63 | 2.88 | 1.97 | 2.01 | 2.07 |
| Other imports[8] | 0.43 | 0.11 | 0.11 | 0.16 | 0.09 | 0.13 | 0.34 | 0.70 | 0.84 | 1.49 |
| **Total** | **28.66** | **21.72** | **23.26** | **24.60** | **22.07** | **24.41** | **27.08** | **21.64** | **24.55** | **28.95** |
| **Exports** | | | | | | | | | | |
| Liquid fuels and other petroleum[9] | 6.08 | 5.41 | 5.37 | 5.28 | 5.33 | 5.25 | 5.33 | 5.72 | 5.71 | 5.86 |
| Natural gas[10] | 1.52 | 2.69 | 2.67 | 2.65 | 5.38 | 4.71 | 4.63 | 6.50 | 5.56 | 5.38 |
| Coal | 2.75 | 3.11 | 3.13 | 3.10 | 3.50 | 3.51 | 3.51 | 3.79 | 3.79 | 3.82 |
| **Total** | **10.35** | **11.21** | **11.17** | **11.03** | **14.22** | **13.47** | **13.47** | **16.01** | **15.06** | **15.07** |
| **Discrepancy[11]** | **-0.36** | **0.21** | **0.21** | **0.20** | **0.32** | **0.30** | **0.41** | **0.29** | **0.32** | **0.50** |
| **Consumption** | | | | | | | | | | |
| Liquid fuels and other petroleum[12] | 37.02 | 35.91 | 37.54 | 39.02 | 33.05 | 36.08 | 38.64 | 32.32 | 36.07 | 40.00 |
| Natural gas | 24.91 | 26.08 | 26.77 | 27.52 | 26.05 | 27.95 | 29.75 | 27.60 | 29.83 | 31.49 |
| Coal[13] | 19.66 | 17.17 | 18.59 | 19.74 | 18.11 | 19.70 | 20.88 | 18.73 | 20.35 | 21.97 |
| Nuclear / uranium[2] | 8.26 | 9.16 | 9.25 | 9.25 | 9.41 | 9.49 | 9.60 | 8.91 | 9.44 | 11.47 |
| Hydropower | 3.17 | 2.81 | 2.83 | 2.84 | 2.84 | 2.87 | 2.90 | 2.90 | 2.92 | 2.95 |
| Biomass[14] | 2.74 | 3.33 | 3.53 | 3.57 | 3.64 | 3.94 | 4.09 | 4.18 | 4.91 | 5.33 |
| Other renewable energy[4] | 1.58 | 2.19 | 2.22 | 2.51 | 2.36 | 2.50 | 3.14 | 2.81 | 3.84 | 5.86 |
| Other[15] | 0.35 | 0.31 | 0.31 | 0.31 | 0.26 | 0.28 | 0.28 | 0.29 | 0.29 | 0.30 |
| **Total** | **97.70** | **96.95** | **101.04** | **104.76** | **95.72** | **102.81** | **109.28** | **97.74** | **107.64** | **119.37** |
| **Prices (2011 dollars per unit)** | | | | | | | | | | |
| Crude oil spot prices (dollars per barrel) | | | | | | | | | | |
| Brent | 111.26 | 103.47 | 105.57 | 107.22 | 127.05 | 130.47 | 133.60 | 157.47 | 162.68 | 168.70 |
| West Texas Intermediate | 94.86 | 101.51 | 103.57 | 105.19 | 125.11 | 128.47 | 131.55 | 155.53 | 160.68 | 166.63 |
| Natural gas at Henry Hub (dollars per million Btu) | 3.98 | 3.78 | 4.13 | 4.54 | 5.11 | 5.40 | 6.03 | 7.22 | 7.83 | 8.44 |
| Coal (dollars per ton) at the minemouth[16] | 41.16 | 49.48 | 49.26 | 49.38 | 55.65 | 55.64 | 56.52 | 60.63 | 61.28 | 62.91 |
| Coal (dollars per million Btu) at the minemouth[16] | 2.04 | 2.46 | 2.45 | 2.47 | 2.78 | 2.79 | 2.83 | 3.04 | 3.08 | 3.17 |
| Average end-use[17] | 2.57 | 2.73 | 2.77 | 2.82 | 3.03 | 3.10 | 3.17 | 3.34 | 3.42 | 3.53 |
| Average electricity (cents per kilowatthour) | 9.9 | 9.5 | 9.4 | 9.5 | 9.6 | 9.7 | 10.0 | 10.4 | 10.8 | 11.2 |

## Table B1. Total energy supply, disposition, and price summary (continued)
(quadrillion Btu per year, unless otherwise noted)

| Supply, disposition, and prices | 2011 | Projections | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | | 2020 | | | 2030 | | | 2040 | | |
| | | 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)** | | | | | | | | | | |
| Crude oil spot prices (dollars per barrel) | | | | | | | | | | |
| Brent | 111.26 | 128.51 | 121.73 | 120.63 | 223.19 | 180.04 | 173.06 | 395.38 | 268.50 | 249.71 |
| West Texas Intermediate | 94.86 | 126.08 | 119.43 | 118.34 | 219.76 | 177.28 | 170.41 | 390.52 | 265.20 | 246.64 |
| Natural gas at Henry Hub | | | | | | | | | | |
| (dollars per million Btu) | 3.98 | 4.69 | 4.77 | 5.11 | 8.98 | 7.45 | 7.82 | 18.12 | 12.92 | 12.49 |
| Coal (dollars per ton) | | | | | | | | | | |
| at the minemouth[16] | 41.16 | 61.45 | 56.81 | 55.55 | 97.75 | 76.78 | 73.22 | 152.24 | 101.14 | 93.11 |
| Coal (dollars per million Btu) | | | | | | | | | | |
| at the minemouth[16] | 2.04 | 3.06 | 2.83 | 2.77 | 4.88 | 3.85 | 3.67 | 7.64 | 5.08 | 4.70 |
| Average end-use[17] | 2.57 | 3.38 | 3.19 | 3.18 | 5.33 | 4.28 | 4.11 | 8.38 | 5.65 | 5.23 |
| Average electricity (cents per kilowatthour) | 9.9 | 11.8 | 10.8 | 10.7 | 16.8 | 13.4 | 13.0 | 26.1 | 17.8 | 16.6 |

[1]Includes waste coal.
[2]These values represent the energy obtained from uranium when it is used in light water reactors. The total energy content of uranium is much larger, but alternative processes are required to take advantage of it.
[3]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.
[4]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 data.
[5]Includes non-biogenic municipal waste, liquid hydrogen, methanol, and some domestic inputs to refineries.
[6]Includes imports of finished petroleum products, unfinished oils, alcohols, ethers, blending components, and renewable fuels such as ethanol.
[7]Includes imports of liquefied natural gas that are later re-exported.
[8]Includes coal, coal coke (net), and electricity (net). Excludes imports of fuel used in nuclear power plants.
[9]Includes crude oil, petroleum products, ethanol, and biodiesel.
[10]Includes re-exported liquefied natural gas.
[11]Balancing item. Includes unaccounted for supply, losses, gains, and net storage withdrawals.
[12]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.
[13]Excludes coal converted to coal-based synthetic liquids and natural gas.
[14]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.
[15]Includes non-biogenic municipal waste, liquid hydrogen, and net electricity imports.
[16]Includes reported prices for both open market and captive mines. Prices weighted by production, which differs from average minemouth prices published in EIA data reports where it is weighted by reported sales.
[17]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 2011 are model results and may differ slightly from official EIA data reports.
**Sources:** 2011 natural gas supply values: U.S. Energy Information Administration (EIA), *Natural Gas Monthly*, DOE/EIA-0130(2012/07) (Washington, DC, July 2012). 2011 natural gas spot price at Henry Hub based on daily data from Natural Gas Intelligence. 2011 coal minemouth and delivered coal prices: EIA, *Annual Coal Report 2011*, DOE/EIA-0584(2011) (Washington, DC, November 2012). 2011 petroleum supply values: EIA, *Petroleum Supply Annual 2011*, DOE/EIA-0340(2011)/1 (Washington, DC, August 2012). 2011 crude oil spot prices: Thomson Reuters. Other 2011 coal values: *Quarterly Coal Report, October-December 2011*, DOE/EIA-0121(2011/4Q) (Washington, DC, March 2012). Other 2011 values: EIA, *Annual Energy Review 2011*, DOE/EIA-0384(2011) (Washington, DC, September 2012). **Projections:** EIA, AEO2013 National Energy Modeling System runs LOWMACRO.D110912A, REF2013.D102312A, and HIGHMACRO.D110912A.

## Table B2. Energy consumption by sector and source
(quadrillion Btu per year, unless otherwise noted)

| Sector and source | 2011 | Projections | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | | 2020 | | | 2030 | | | 2040 | | |
| | | Low economic growth | Reference | High economic growth | Low economic growth | Reference | High economic growth | Low economic growth | Reference | High economic growth |
| **Energy consumption** | | | | | | | | | | |
| **Residential** | | | | | | | | | | |
| Propane | 0.53 | 0.52 | 0.52 | 0.53 | 0.50 | 0.52 | 0.55 | 0.49 | 0.52 | 0.57 |
| Kerosene | 0.02 | 0.01 | 0.01 | 0.02 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 |
| Distillate fuel oil | 0.59 | 0.51 | 0.51 | 0.51 | 0.40 | 0.40 | 0.40 | 0.32 | 0.32 | 0.32 |
| Liquid fuels and other petroleum subtotal | 1.14 | 1.04 | 1.05 | 1.05 | 0.91 | 0.93 | 0.96 | 0.82 | 0.86 | 0.91 |
| Natural gas | 4.83 | 4.58 | 4.62 | 4.69 | 4.27 | 4.46 | 4.67 | 3.93 | 4.23 | 4.57 |
| Coal | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.00 | 0.00 | 0.00 |
| Renewable energy[1] | 0.45 | 0.43 | 0.44 | 0.45 | 0.42 | 0.45 | 0.47 | 0.42 | 0.45 | 0.50 |
| Electricity | 4.86 | 4.67 | 4.84 | 5.02 | 4.97 | 5.36 | 5.85 | 5.38 | 6.03 | 6.90 |
| **Delivered energy** | **11.28** | **10.72** | **10.95** | **11.21** | **10.58** | **11.20** | **11.96** | **10.55** | **11.57** | **12.88** |
| Electricity related losses | 10.20 | 9.30 | 9.66 | 10.02 | 9.80 | 10.45 | 11.30 | 10.27 | 11.50 | 13.30 |
| **Total** | **21.48** | **20.02** | **20.62** | **21.24** | **20.38** | **21.65** | **23.26** | **20.82** | **23.08** | **26.17** |
| **Commercial** | | | | | | | | | | |
| Propane | 0.14 | 0.16 | 0.16 | 0.16 | 0.16 | 0.16 | 0.17 | 0.17 | 0.17 | 0.17 |
| Motor gasoline[2] | 0.05 | 0.05 | 0.05 | 0.05 | 0.06 | 0.06 | 0.06 | 0.06 | 0.06 | 0.06 |
| Kerosene | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 0.01 |
| Distillate fuel oil | 0.42 | 0.34 | 0.34 | 0.34 | 0.32 | 0.32 | 0.32 | 0.30 | 0.30 | 0.30 |
| Residual fuel oil | 0.07 | 0.10 | 0.09 | 0.09 | 0.09 | 0.09 | 0.09 | 0.08 | 0.09 | 0.09 |
| Liquid fuels and other petroleum subtotal | 0.69 | 0.66 | 0.65 | 0.65 | 0.64 | 0.64 | 0.64 | 0.62 | 0.63 | 0.63 |
| Natural gas | 3.23 | 3.42 | 3.40 | 3.37 | 3.51 | 3.50 | 3.49 | 3.65 | 3.68 | 3.72 |
| Coal | 0.05 | 0.05 | 0.05 | 0.05 | 0.05 | 0.05 | 0.05 | 0.05 | 0.05 | 0.05 |
| Renewable energy[3] | 0.13 | 0.13 | 0.13 | 0.13 | 0.13 | 0.13 | 0.13 | 0.13 | 0.13 | 0.13 |
| Electricity | 4.50 | 4.68 | 4.72 | 4.73 | 5.16 | 5.22 | 5.27 | 5.61 | 5.72 | 5.82 |
| **Delivered energy** | **8.60** | **8.93** | **8.95** | **8.93** | **9.48** | **9.54** | **9.57** | **10.06** | **10.21** | **10.35** |
| Electricity related losses | 9.45 | 9.30 | 9.42 | 9.44 | 10.18 | 10.18 | 10.16 | 10.72 | 10.92 | 11.22 |
| **Total** | **18.05** | **18.23** | **18.37** | **18.38** | **19.66** | **19.72** | **19.73** | **20.78** | **21.13** | **21.57** |
| **Industrial[4]** | | | | | | | | | | |
| Liquefied petroleum gases | 2.10 | 2.33 | 2.46 | 2.56 | 2.20 | 2.47 | 2.59 | 2.02 | 2.30 | 2.57 |
| Propylene | 0.40 | 0.52 | 0.56 | 0.58 | 0.46 | 0.52 | 0.55 | 0.41 | 0.46 | 0.51 |
| Motor gasoline[2] | 0.27 | 0.29 | 0.32 | 0.35 | 0.28 | 0.32 | 0.35 | 0.28 | 0.32 | 0.36 |
| Distillate fuel oil | 1.21 | 1.10 | 1.22 | 1.37 | 1.02 | 1.18 | 1.35 | 1.06 | 1.22 | 1.41 |
| Residual fuel oil | 0.11 | 0.10 | 0.11 | 0.12 | 0.10 | 0.11 | 0.12 | 0.10 | 0.11 | 0.12 |
| Petrochemical feedstocks | 0.88 | 1.01 | 1.03 | 1.06 | 1.03 | 1.08 | 1.13 | 1.02 | 1.09 | 1.16 |
| Other petroleum[5] | 3.61 | 3.26 | 3.54 | 3.86 | 3.04 | 3.46 | 3.87 | 3.16 | 3.65 | 4.13 |
| Liquid fuels and other petroleum subtotal | 8.57 | 8.60 | 9.25 | 9.88 | 8.11 | 9.14 | 9.96 | 8.04 | 9.16 | 10.26 |
| Natural gas | 6.92 | 7.41 | 7.86 | 8.28 | 7.13 | 7.97 | 8.70 | 7.01 | 8.08 | 9.38 |
| Natural-gas-to-liquids heat and power | 0.00 | 0.07 | 0.13 | 0.13 | 0.11 | 0.21 | 0.21 | 0.16 | 0.33 | 0.36 |
| Lease and plant fuel[6] | 1.42 | 1.54 | 1.57 | 1.60 | 1.74 | 1.73 | 1.80 | 1.96 | 1.97 | 2.07 |
| Natural gas subtotal | 8.34 | 9.02 | 9.56 | 10.01 | 8.98 | 9.91 | 10.72 | 9.13 | 10.38 | 11.81 |
| Metallurgical coal | 0.56 | 0.55 | 0.60 | 0.68 | 0.45 | 0.52 | 0.63 | 0.38 | 0.46 | 0.63 |
| Other industrial coal | 1.04 | 0.96 | 1.00 | 1.04 | 0.94 | 1.00 | 1.06 | 0.97 | 1.05 | 1.14 |
| Coal-to-liquids heat and power | 0.00 | 0.00 | 0.00 | 0.11 | 0.00 | 0.09 | 0.17 | 0.10 | 0.15 | 0.29 |
| Net coal coke imports | 0.01 | -0.01 | -0.01 | -0.01 | -0.04 | -0.04 | -0.05 | -0.05 | -0.05 | -0.06 |
| Coal subtotal | 1.62 | 1.50 | 1.58 | 1.81 | 1.35 | 1.57 | 1.81 | 1.41 | 1.61 | 2.00 |
| Biofuels heat and coproducts | 0.67 | 0.80 | 0.82 | 0.84 | 0.83 | 0.85 | 0.87 | 1.14 | 1.37 | 1.40 |
| Renewable energy[7] | 1.51 | 1.58 | 1.72 | 1.80 | 1.70 | 1.97 | 2.11 | 1.94 | 2.28 | 2.53 |
| Electricity | 3.33 | 3.65 | 3.95 | 4.22 | 3.49 | 3.96 | 4.35 | 3.42 | 3.91 | 4.55 |
| **Delivered energy** | **24.04** | **25.15** | **26.87** | **28.56** | **24.48** | **27.40** | **29.83** | **25.09** | **28.71** | **32.55** |
| Electricity related losses | 6.99 | 7.25 | 7.89 | 8.43 | 6.89 | 7.72 | 8.40 | 6.53 | 7.45 | 8.77 |
| **Total** | **31.03** | **32.40** | **34.76** | **36.99** | **31.37** | **35.11** | **38.22** | **31.62** | **36.16** | **41.32** |

## Table B2. Energy consumption by sector and source (continued)
(quadrillion Btu per year, unless otherwise noted)

| Sector and source | 2011 | 2020 Low economic growth | 2020 Reference | 2020 High economic growth | 2030 Low economic growth | 2030 Reference | 2030 High economic growth | 2040 Low economic growth | 2040 Reference | 2040 High economic growth |
|---|---|---|---|---|---|---|---|---|---|---|
| **Transportation** | | | | | | | | | | |
| Propane | 0.06 | 0.06 | 0.06 | 0.06 | 0.06 | 0.07 | 0.08 | 0.07 | 0.08 | 0.10 |
| E85[8] | 0.05 | 0.09 | 0.08 | 0.08 | 0.28 | 0.16 | 0.15 | 0.26 | 0.17 | 0.22 |
| Motor gasoline[2] | 16.31 | 14.49 | 14.88 | 15.14 | 12.01 | 13.06 | 13.70 | 11.10 | 12.64 | 13.61 |
| Jet fuel[9] | 3.01 | 3.08 | 3.11 | 3.14 | 3.22 | 3.28 | 3.34 | 3.32 | 3.42 | 3.53 |
| Distillate fuel oil[10] | 5.91 | 6.72 | 7.28 | 7.83 | 6.64 | 7.61 | 8.60 | 6.90 | 7.90 | 9.51 |
| Residual fuel oil | 0.82 | 0.84 | 0.84 | 0.85 | 0.85 | 0.86 | 0.86 | 0.86 | 0.87 | 0.88 |
| Other petroleum[11] | 0.17 | 0.15 | 0.15 | 0.15 | 0.15 | 0.16 | 0.16 | 0.16 | 0.16 | 0.17 |
| Liquid fuels and other petroleum subtotal | 26.32 | 25.44 | 26.42 | 27.26 | 23.21 | 25.20 | 26.90 | 22.66 | 25.24 | 28.01 |
| Pipeline fuel natural gas | 0.70 | 0.70 | 0.71 | 0.73 | 0.71 | 0.74 | 0.78 | 0.74 | 0.78 | 0.80 |
| Compressed / liquefied natural gas | 0.04 | 0.07 | 0.08 | 0.08 | 0.27 | 0.26 | 0.25 | 0.94 | 1.05 | 1.29 |
| Liquid hydrogen | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 |
| Electricity | 0.02 | 0.03 | 0.03 | 0.03 | 0.04 | 0.04 | 0.05 | 0.06 | 0.07 | 0.07 |
| **Delivered energy** | **27.09** | **26.24** | **27.24** | **28.09** | **24.24** | **26.25** | **27.98** | **24.40** | **27.14** | **30.18** |
| Electricity related losses | 0.05 | 0.06 | 0.06 | 0.06 | 0.08 | 0.09 | 0.09 | 0.12 | 0.13 | 0.14 |
| **Total** | **27.13** | **26.29** | **27.30** | **28.15** | **24.32** | **26.33** | **28.07** | **24.52** | **27.27** | **30.31** |
| **Delivered energy consumption for all sectors** | | | | | | | | | | |
| Liquefied petroleum gases | 2.82 | 3.07 | 3.21 | 3.31 | 2.93 | 3.23 | 3.38 | 2.75 | 3.08 | 3.41 |
| Propylene | 0.40 | 0.52 | 0.56 | 0.58 | 0.46 | 0.52 | 0.55 | 0.41 | 0.46 | 0.51 |
| E85[8] | 0.05 | 0.09 | 0.08 | 0.08 | 0.28 | 0.16 | 0.15 | 0.26 | 0.17 | 0.22 |
| Motor gasoline[2] | 16.64 | 14.84 | 15.26 | 15.54 | 12.35 | 13.43 | 14.12 | 11.44 | 13.03 | 14.03 |
| Jet fuel[9] | 3.01 | 3.08 | 3.11 | 3.14 | 3.22 | 3.28 | 3.34 | 3.32 | 3.42 | 3.53 |
| Kerosene | 0.03 | 0.03 | 0.03 | 0.03 | 0.02 | 0.02 | 0.03 | 0.02 | 0.02 | 0.03 |
| Distillate fuel oil | 8.12 | 8.66 | 9.35 | 10.04 | 8.37 | 9.51 | 10.67 | 8.58 | 9.74 | 11.54 |
| Residual fuel oil | 1.01 | 1.04 | 1.05 | 1.06 | 1.03 | 1.05 | 1.07 | 1.04 | 1.07 | 1.09 |
| Petrochemical feedstocks | 0.88 | 1.01 | 1.03 | 1.06 | 1.03 | 1.08 | 1.13 | 1.02 | 1.09 | 1.16 |
| Other petroleum[12] | 3.77 | 3.40 | 3.69 | 4.00 | 3.19 | 3.61 | 4.02 | 3.31 | 3.80 | 4.29 |
| Liquid fuels and other petroleum subtotal | 36.72 | 35.74 | 37.37 | 38.84 | 32.87 | 35.90 | 38.45 | 32.14 | 35.88 | 39.80 |
| Natural gas | 15.03 | 15.48 | 15.95 | 16.42 | 15.19 | 16.19 | 17.11 | 15.52 | 17.05 | 18.95 |
| Natural-gas-to-liquids heat and power | 0.00 | 0.07 | 0.13 | 0.13 | 0.11 | 0.21 | 0.21 | 0.16 | 0.33 | 0.36 |
| Lease and plant fuel[6] | 1.42 | 1.54 | 1.57 | 1.60 | 1.74 | 1.73 | 1.80 | 1.96 | 1.97 | 2.07 |
| Pipeline natural gas | 0.70 | 0.70 | 0.71 | 0.73 | 0.71 | 0.74 | 0.78 | 0.74 | 0.78 | 0.80 |
| Natural gas subtotal | 17.15 | 17.79 | 18.36 | 18.88 | 17.75 | 18.87 | 19.90 | 18.39 | 20.13 | 22.19 |
| Metallurgical coal | 0.56 | 0.55 | 0.60 | 0.68 | 0.45 | 0.52 | 0.63 | 0.38 | 0.46 | 0.63 |
| Other coal | 1.10 | 1.02 | 1.06 | 1.10 | 1.00 | 1.06 | 1.11 | 1.03 | 1.11 | 1.20 |
| Coal-to-liquids heat and power | 0.00 | 0.00 | 0.00 | 0.11 | 0.00 | 0.09 | 0.17 | 0.10 | 0.15 | 0.29 |
| Net coal coke imports | 0.01 | -0.01 | -0.01 | -0.01 | -0.04 | -0.04 | -0.05 | -0.05 | -0.05 | -0.06 |
| Coal subtotal | 1.67 | 1.56 | 1.64 | 1.87 | 1.41 | 1.63 | 1.87 | 1.47 | 1.67 | 2.06 |
| Biofuels heat and coproducts | 0.67 | 0.80 | 0.82 | 0.84 | 0.83 | 0.85 | 0.87 | 1.14 | 1.37 | 1.40 |
| Renewable energy[13] | 2.08 | 2.13 | 2.28 | 2.37 | 2.25 | 2.54 | 2.71 | 2.48 | 2.86 | 3.16 |
| Liquid hydrogen | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 |
| Electricity | 12.71 | 13.03 | 13.54 | 14.01 | 13.66 | 14.59 | 15.52 | 14.48 | 15.72 | 17.34 |
| **Delivered energy** | **71.01** | **71.04** | **74.01** | **76.80** | **68.77** | **74.38** | **79.33** | **70.10** | **77.63** | **85.95** |
| Electricity related losses | 26.69 | 25.91 | 27.03 | 27.96 | 26.95 | 28.43 | 29.95 | 27.64 | 30.00 | 33.42 |
| **Total** | **97.70** | **96.95** | **101.04** | **104.76** | **95.72** | **102.81** | **109.28** | **97.74** | **107.64** | **119.37** |
| **Electric power[14]** | | | | | | | | | | |
| Distillate fuel oil | 0.06 | 0.08 | 0.08 | 0.08 | 0.08 | 0.08 | 0.08 | 0.08 | 0.08 | 0.08 |
| Residual fuel oil | 0.23 | 0.09 | 0.10 | 0.10 | 0.10 | 0.10 | 0.11 | 0.10 | 0.11 | 0.12 |
| Liquid fuels and other petroleum subtotal | 0.30 | 0.17 | 0.18 | 0.18 | 0.17 | 0.18 | 0.19 | 0.18 | 0.19 | 0.20 |
| Natural gas | 7.76 | 8.29 | 8.40 | 8.65 | 8.30 | 9.08 | 9.84 | 9.21 | 9.70 | 9.30 |
| Steam coal | 17.99 | 15.61 | 16.95 | 17.87 | 16.71 | 18.07 | 19.01 | 17.26 | 18.68 | 19.91 |
| Nuclear / uranium[15] | 8.26 | 9.16 | 9.25 | 9.25 | 9.41 | 9.49 | 9.60 | 8.91 | 9.44 | 11.47 |
| Renewable energy[16] | 4.74 | 5.39 | 5.49 | 5.72 | 5.76 | 5.93 | 6.55 | 6.27 | 7.44 | 9.59 |
| Electricity imports | 0.13 | 0.08 | 0.08 | 0.08 | 0.03 | 0.05 | 0.05 | 0.06 | 0.06 | 0.07 |
| **Total[17]** | **39.40** | **38.94** | **40.57** | **41.97** | **40.61** | **43.02** | **45.47** | **42.12** | **45.73** | **50.76** |

## Table B2. Energy consumption by sector and source (continued)
(quadrillion Btu per year, unless otherwise noted)

| Sector and source | 2011 | Projections | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | | 2020 | | | 2030 | | | 2040 | | |
| | | 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 | 2.82 | 3.07 | 3.21 | 3.31 | 2.93 | 3.23 | 3.38 | 2.75 | 3.08 | 3.41 |
| Propylene | 0.40 | 0.52 | 0.56 | 0.58 | 0.46 | 0.52 | 0.55 | 0.41 | 0.46 | 0.51 |
| E85[8] | 0.05 | 0.09 | 0.08 | 0.08 | 0.28 | 0.16 | 0.15 | 0.26 | 0.17 | 0.22 |
| Motor gasoline[2] | 16.64 | 14.84 | 15.26 | 15.54 | 12.35 | 13.43 | 14.12 | 11.44 | 13.03 | 14.03 |
| Jet fuel[9] | 3.01 | 3.08 | 3.11 | 3.14 | 3.22 | 3.28 | 3.34 | 3.32 | 3.42 | 3.53 |
| Kerosene | 0.03 | 0.03 | 0.03 | 0.03 | 0.02 | 0.02 | 0.03 | 0.02 | 0.02 | 0.03 |
| Distillate fuel oil | 8.18 | 8.74 | 9.43 | 10.12 | 8.45 | 9.59 | 10.75 | 8.65 | 9.82 | 11.62 |
| Residual fuel oil | 1.24 | 1.13 | 1.15 | 1.16 | 1.13 | 1.15 | 1.17 | 1.15 | 1.17 | 1.21 |
| Petrochemical feedstocks | 0.88 | 1.01 | 1.03 | 1.06 | 1.03 | 1.08 | 1.13 | 1.02 | 1.09 | 1.16 |
| Other petroleum[12] | 3.77 | 3.40 | 3.69 | 4.00 | 3.19 | 3.61 | 4.02 | 3.31 | 3.80 | 4.29 |
| Liquid fuels and other petroleum subtotal | 37.02 | 35.91 | 37.54 | 39.02 | 33.05 | 36.08 | 38.64 | 32.32 | 36.07 | 40.00 |
| Natural gas | 22.79 | 23.78 | 24.36 | 25.07 | 23.49 | 25.27 | 26.96 | 24.73 | 26.75 | 28.26 |
| Natural-gas-to-liquids heat and power | 0.00 | 0.07 | 0.13 | 0.13 | 0.11 | 0.21 | 0.21 | 0.16 | 0.33 | 0.36 |
| Lease and plant fuel[6] | 1.42 | 1.54 | 1.57 | 1.60 | 1.74 | 1.73 | 1.80 | 1.96 | 1.97 | 2.07 |
| Pipeline natural gas | 0.70 | 0.70 | 0.71 | 0.73 | 0.71 | 0.74 | 0.78 | 0.74 | 0.78 | 0.80 |
| Natural gas subtotal | 24.91 | 26.08 | 26.77 | 27.52 | 26.05 | 27.95 | 29.75 | 27.60 | 29.83 | 31.49 |
| Metallurgical coal | 0.56 | 0.55 | 0.60 | 0.68 | 0.45 | 0.52 | 0.63 | 0.38 | 0.46 | 0.63 |
| Other coal | 19.09 | 16.63 | 18.01 | 18.97 | 17.70 | 19.12 | 20.13 | 18.28 | 19.79 | 21.11 |
| Coal-to-liquids heat and power | 0.00 | 0.00 | 0.00 | 0.11 | 0.00 | 0.09 | 0.17 | 0.10 | 0.15 | 0.29 |
| Net coal coke imports | 0.01 | -0.01 | -0.01 | -0.01 | -0.04 | -0.04 | -0.05 | -0.05 | -0.05 | -0.06 |
| Coal subtotal | 19.66 | 17.17 | 18.59 | 19.74 | 18.11 | 19.70 | 20.88 | 18.73 | 20.35 | 21.97 |
| Nuclear / uranium[15] | 8.26 | 9.16 | 9.25 | 9.25 | 9.41 | 9.49 | 9.60 | 8.91 | 9.44 | 11.47 |
| Biofuels heat and coproducts | 0.67 | 0.80 | 0.82 | 0.84 | 0.83 | 0.85 | 0.87 | 1.14 | 1.37 | 1.40 |
| Renewable energy[18] | 6.82 | 7.53 | 7.77 | 8.09 | 8.01 | 8.47 | 9.25 | 8.75 | 10.30 | 12.74 |
| Liquid hydrogen | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 |
| Electricity imports | 0.13 | 0.08 | 0.08 | 0.08 | 0.03 | 0.05 | 0.05 | 0.06 | 0.06 | 0.07 |
| **Total** | **97.70** | **96.95** | **101.04** | **104.76** | **95.72** | **102.81** | **109.28** | **97.74** | **107.64** | **119.37** |
| **Energy use and related statistics** | | | | | | | | | | |
| Delivered energy use | 71.01 | 71.04 | 74.01 | 76.80 | 68.77 | 74.38 | 79.33 | 70.10 | 77.63 | 85.95 |
| Total energy use | 97.70 | 96.95 | 101.04 | 104.76 | 95.72 | 102.81 | 109.28 | 97.74 | 107.64 | 119.37 |
| Ethanol consumed in motor gasoline and E85 | 1.17 | 1.31 | 1.34 | 1.37 | 1.22 | 1.24 | 1.29 | 1.13 | 1.21 | 1.32 |
| Population (millions) | 312.38 | 338.25 | 340.45 | 342.94 | 367.06 | 372.41 | 378.73 | 395.19 | 404.39 | 415.38 |
| Gross domestic product (billion 2005 dollars) | 13,299 | 15,717 | 16,859 | 17,754 | 18,703 | 21,355 | 23,232 | 23,283 | 27,277 | 30,552 |
| Carbon dioxide emissions (million metric tons) | 5,471 | 5,192 | 5,455 | 5,685 | 5,095 | 5,523 | 5,882 | 5,197 | 5,691 | 6,163 |

[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 water heating, and electricity generation from wind and solar photovoltaic sources.
[2]Includes ethanol (blends of 15 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 water heating and electricity generation from wind and solar photovoltaic sources.
[4]Includes energy for combined heat and power plants that have a non-regulatory status, and small on-site generating systems.
[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, in natural gas processing plant machinery, and for liquefaction in export facilities.
[7]Includes consumption of energy produced from hydroelectric, wood and wood waste, municipal waste, and other biomass sources. Excludes ethanol blends (15 percent or less) in motor gasoline.
[8]E85 refers to a blend of 85 percent ethanol (renewable) and 15 percent motor gasoline (nonrenewable). To address cold starting issues, the percentage of ethanol varies seasonally. The annual average ethanol content of 74 percent is used for this forecast.
[9]Includes only kerosene type.
[10]Diesel fuel for on- and off- road use.
[11]Includes aviation gasoline and lubricants.
[12]Includes unfinished oils, natural gasoline, motor gasoline blending components, aviation gasoline, lubricants, still gas, asphalt, road oil, petroleum coke, and miscellaneous petroleum products.
[13]Includes electricity generated for sale to the grid and for own use from renewable sources, and non-electric energy from renewable sources. Excludes ethanol and nonmarketed renewable energy consumption for geothermal heat pumps, buildings photovoltaic systems, and solar thermal water heaters.
[14]Includes consumption of energy by electricity-only and combined heat and power plants that have a regulatory status.
[15]These values represent the energy obtained from uranium when it is used in light water reactors. The total energy content of uranium is much larger, but alternative processes are required to take advantage of it.
[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 water heaters.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Data for 2011 are model results and may differ slightly from official EIA data reports.
**Sources:** 2011 consumption based on: U.S. Energy Information Administration (EIA), *Annual Energy Review 2011*, DOE/EIA-0384(2011) (Washington, DC, September 2012). 2011 population and gross domestic product: IHS Global Insight Industry and Employment models, August 2012. 2011 carbon dioxide emissions: EIA, *Monthly Energy Review*, DOE/EIA-0035(2012/08) (Washington, DC, August 2012). **Projections:** EIA, AEO2013 National Energy Modeling System runs LOWMACRO.D110912A, REF2013.D102312A, and HIGHMACRO.D110912A.

## Table B3. Energy prices by sector and source
(2011 dollars per million Btu, unless otherwise noted)

| Sector and source | 2011 | 2020 Low economic growth | 2020 Reference | 2020 High economic growth | 2030 Low economic growth | 2030 Reference | 2030 High economic growth | 2040 Low economic growth | 2040 Reference | 2040 High economic growth |
|---|---|---|---|---|---|---|---|---|---|---|
| **Residential** | | | | | | | | | | |
| Propane | 25.06 | 22.83 | 23.41 | 23.91 | 25.25 | 25.73 | 26.28 | 27.58 | 27.99 | 28.56 |
| Distillate fuel oil | 26.38 | 26.37 | 26.91 | 27.27 | 30.41 | 31.26 | 32.06 | 35.37 | 36.54 | 38.26 |
| Natural gas | 10.80 | 11.37 | 11.78 | 12.30 | 12.88 | 13.37 | 14.11 | 15.56 | 16.36 | 17.95 |
| Electricity | 34.34 | 34.22 | 33.62 | 33.85 | 34.42 | 34.56 | 35.14 | 36.31 | 37.10 | 37.97 |
| **Commercial** | | | | | | | | | | |
| Propane | 22.10 | 19.32 | 20.04 | 20.66 | 22.35 | 22.97 | 23.68 | 25.39 | 25.94 | 26.76 |
| Distillate fuel oil | 25.87 | 23.83 | 24.26 | 24.60 | 27.76 | 28.51 | 29.24 | 32.62 | 33.74 | 35.73 |
| Residual fuel oil | 19.17 | 14.53 | 14.82 | 15.02 | 18.08 | 18.77 | 19.01 | 22.92 | 23.41 | 24.06 |
| Natural gas | 8.84 | 9.09 | 9.47 | 9.94 | 10.28 | 10.70 | 11.33 | 12.53 | 13.21 | 14.14 |
| Electricity | 29.98 | 28.71 | 28.57 | 29.21 | 27.98 | 28.65 | 29.76 | 30.39 | 31.75 | 33.42 |
| **Industrial**[1] | | | | | | | | | | |
| Propane | 22.54 | 19.74 | 20.51 | 21.15 | 22.96 | 23.64 | 24.37 | 26.16 | 26.78 | 28.08 |
| Distillate fuel oil | 26.50 | 24.31 | 24.67 | 25.00 | 28.22 | 28.91 | 29.58 | 33.09 | 34.16 | 36.05 |
| Residual fuel oil | 18.86 | 16.89 | 17.19 | 17.41 | 20.52 | 21.09 | 21.34 | 25.37 | 25.78 | 26.36 |
| Natural gas[2] | 4.89 | 5.19 | 5.53 | 5.98 | 6.26 | 6.56 | 7.13 | 8.37 | 8.88 | 9.43 |
| Metallurgical coal | 7.01 | 8.81 | 8.75 | 8.74 | 10.12 | 10.09 | 10.13 | 11.03 | 11.11 | 11.32 |
| Other industrial coal | 3.43 | 3.44 | 3.44 | 3.47 | 3.66 | 3.71 | 3.77 | 3.99 | 4.06 | 4.12 |
| Coal to liquids | - - | - - | - - | 2.11 | - - | 2.55 | 2.60 | 2.90 | 2.95 | 2.90 |
| Electricity | 19.98 | 18.57 | 18.72 | 19.41 | 18.99 | 19.73 | 20.86 | 21.45 | 22.74 | 24.31 |
| **Transportation** | | | | | | | | | | |
| Propane | 26.06 | 23.89 | 24.48 | 24.97 | 26.32 | 26.80 | 27.35 | 28.65 | 29.07 | 29.89 |
| E85[3] | 25.30 | 28.53 | 29.64 | 30.12 | 27.32 | 26.94 | 28.58 | 31.85 | 30.58 | 33.52 |
| Motor gasoline[4] | 28.70 | 27.57 | 27.84 | 28.24 | 30.16 | 30.73 | 31.28 | 35.10 | 36.18 | 37.96 |
| Jet fuel[5] | 22.49 | 21.10 | 21.50 | 21.81 | 25.48 | 26.03 | 26.70 | 30.65 | 31.07 | 32.93 |
| Diesel fuel (distillate fuel oil)[6] | 26.15 | 26.27 | 26.61 | 26.93 | 30.14 | 30.81 | 31.46 | 34.97 | 36.05 | 38.06 |
| Residual fuel oil | 17.83 | 14.64 | 14.91 | 15.13 | 17.92 | 18.34 | 18.74 | 21.98 | 22.45 | 23.37 |
| Natural gas[7] | 16.14 | 16.27 | 16.87 | 17.45 | 17.96 | 18.90 | 19.62 | 19.76 | 21.20 | 22.26 |
| Electricity | 32.77 | 29.28 | 29.60 | 30.42 | 30.50 | 31.53 | 32.82 | 33.31 | 35.07 | 36.84 |
| **Electric power**[8] | | | | | | | | | | |
| Distillate fuel oil | 23.30 | 21.90 | 22.45 | 22.82 | 25.93 | 26.80 | 27.58 | 30.87 | 32.03 | 34.00 |
| Residual fuel oil | 15.97 | 24.65 | 24.94 | 25.22 | 29.03 | 29.36 | 29.79 | 34.04 | 34.54 | 35.34 |
| Natural gas | 4.77 | 4.54 | 4.90 | 5.34 | 5.69 | 6.05 | 6.66 | 7.86 | 8.38 | 8.79 |
| Steam coal | 2.38 | 2.47 | 2.52 | 2.57 | 2.81 | 2.87 | 2.92 | 3.13 | 3.20 | 3.27 |
| **Average price to all users**[9] | | | | | | | | | | |
| Propane | 17.13 | 12.84 | 13.69 | 14.51 | 17.27 | 18.14 | 19.37 | 22.77 | 23.79 | 25.04 |
| E85[3] | 25.30 | 28.53 | 29.64 | 30.12 | 27.32 | 26.94 | 28.58 | 31.85 | 30.58 | 33.52 |
| Motor gasoline[4] | 28.47 | 27.57 | 27.84 | 28.24 | 30.15 | 30.72 | 31.28 | 35.10 | 36.17 | 37.95 |
| Jet fuel[5] | 22.49 | 21.10 | 21.50 | 21.81 | 25.48 | 26.03 | 26.70 | 30.65 | 31.07 | 32.93 |
| Distillate fuel oil | 26.18 | 25.90 | 26.25 | 26.57 | 29.80 | 30.48 | 31.15 | 34.64 | 35.73 | 37.72 |
| Residual fuel oil | 17.65 | 15.66 | 15.97 | 16.22 | 19.10 | 19.59 | 20.02 | 23.41 | 23.95 | 24.89 |
| Natural gas | 6.68 | 6.74 | 7.07 | 7.50 | 7.99 | 8.27 | 8.82 | 10.36 | 10.94 | 11.77 |
| Metallurgical coal | 7.01 | 8.81 | 8.75 | 8.74 | 10.12 | 10.09 | 10.13 | 11.03 | 11.11 | 11.32 |
| Other coal | 2.45 | 2.53 | 2.57 | 2.62 | 2.86 | 2.92 | 2.97 | 3.18 | 3.25 | 3.32 |
| Coal to liquids | - - | - - | - - | 2.11 | - - | 2.55 | 2.60 | 2.90 | 2.95 | 2.90 |
| Electricity | 29.03 | 27.85 | 27.50 | 27.92 | 28.03 | 28.41 | 29.31 | 30.49 | 31.58 | 32.86 |
| **Non-renewable energy expenditures by sector (billion 2011 dollars)** | | | | | | | | | | |
| Residential | 248.08 | 237.55 | 243.44 | 254.57 | 251.11 | 271.05 | 299.14 | 281.74 | 319.63 | 372.95 |
| Commercial | 179.97 | 179.72 | 181.68 | 186.63 | 196.60 | 203.80 | 213.44 | 234.84 | 249.60 | 267.32 |
| Industrial | 225.18 | 233.96 | 259.03 | 287.38 | 253.14 | 294.99 | 337.55 | 296.17 | 353.70 | 430.16 |
| Transportation | 718.25 | 660.22 | 694.73 | 727.04 | 671.51 | 749.40 | 817.74 | 779.09 | 900.68 | 1,055.41 |
| Total non-renewable expenditures | 1,371.48 | 1,311.46 | 1,378.87 | 1,455.61 | 1,372.36 | 1,519.24 | 1,667.86 | 1,591.84 | 1,823.61 | 2,125.83 |
| Transportation renewable expenditures | 1.24 | 2.69 | 2.44 | 2.52 | 7.56 | 4.39 | 4.34 | 8.39 | 5.05 | 7.26 |
| **Total expenditures** | **1,372.71** | **1,314.15** | **1,381.31** | **1,458.13** | **1,379.92** | **1,523.63** | **1,672.20** | **1,600.24** | **1,828.66** | **2,133.08** |

**Table B3. Energy prices by sector and source (continued)**
(nominal dollars per million Btu, unless otherwise noted)

| Sector and source | 2011 | Projections | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | | 2020 | | | 2030 | | | 2040 | | |
| | | Low economic growth | Reference | High economic growth | Low economic growth | Reference | High economic growth | Low economic growth | Reference | High economic growth |
| **Residential** | | | | | | | | | | |
| Propane | 25.06 | 28.35 | 27.00 | 26.90 | 44.35 | 35.51 | 34.04 | 69.24 | 46.20 | 42.27 |
| Distillate fuel oil | 26.38 | 32.75 | 31.03 | 30.68 | 53.42 | 43.14 | 41.52 | 88.80 | 60.31 | 56.64 |
| Natural gas | 10.80 | 14.12 | 13.58 | 13.84 | 22.63 | 18.45 | 18.28 | 39.07 | 27.01 | 26.56 |
| Electricity | 34.34 | 42.50 | 38.76 | 38.08 | 60.47 | 47.69 | 45.53 | 91.16 | 61.23 | 56.21 |
| **Commercial** | | | | | | | | | | |
| Propane | 22.10 | 24.00 | 23.11 | 23.24 | 39.26 | 31.70 | 30.67 | 63.74 | 42.82 | 39.60 |
| Distillate fuel oil | 25.87 | 29.60 | 27.97 | 27.68 | 48.76 | 39.34 | 37.87 | 81.91 | 55.68 | 52.88 |
| Residual fuel oil | 19.17 | 18.05 | 17.09 | 16.90 | 31.77 | 25.90 | 24.63 | 57.55 | 38.64 | 35.61 |
| Natural gas | 8.84 | 11.29 | 10.92 | 11.18 | 18.06 | 14.76 | 14.68 | 31.47 | 21.81 | 20.92 |
| Electricity | 29.98 | 35.65 | 32.94 | 32.86 | 49.15 | 39.54 | 38.56 | 76.30 | 52.40 | 49.46 |
| **Industrial**[1] | | | | | | | | | | |
| Propane | 22.54 | 24.52 | 23.65 | 23.80 | 40.33 | 32.62 | 31.57 | 65.69 | 44.20 | 41.56 |
| Distillate fuel oil | 26.50 | 30.19 | 28.45 | 28.12 | 49.57 | 39.89 | 38.32 | 83.08 | 56.39 | 53.36 |
| Residual fuel oil | 18.86 | 20.98 | 19.82 | 19.59 | 36.05 | 29.10 | 27.65 | 63.69 | 42.55 | 39.02 |
| Natural gas[2] | 4.89 | 6.44 | 6.38 | 6.72 | 11.00 | 9.05 | 9.24 | 21.03 | 14.66 | 13.95 |
| Metallurgical coal | 7.01 | 10.94 | 10.09 | 9.83 | 17.78 | 13.92 | 13.12 | 27.68 | 18.34 | 16.76 |
| Other industrial coal | 3.43 | 4.27 | 3.97 | 3.91 | 6.43 | 5.12 | 4.88 | 10.03 | 6.70 | 6.10 |
| Coal to liquids | - - | - - | - - | 2.37 | - - | 3.52 | 3.36 | 7.28 | 4.87 | 4.30 |
| Electricity | 19.98 | 23.07 | 21.59 | 21.83 | 33.37 | 27.22 | 27.03 | 53.86 | 37.54 | 35.99 |
| **Transportation** | | | | | | | | | | |
| Propane | 26.06 | 29.67 | 28.22 | 28.10 | 46.23 | 36.98 | 35.42 | 71.93 | 47.97 | 44.25 |
| E85[3] | 25.30 | 35.44 | 34.18 | 33.89 | 47.99 | 37.18 | 37.02 | 79.96 | 50.46 | 49.62 |
| Motor gasoline[4] | 28.70 | 34.25 | 32.10 | 31.77 | 52.98 | 42.41 | 40.52 | 88.14 | 59.72 | 56.19 |
| Jet fuel[5] | 22.49 | 26.21 | 24.79 | 24.54 | 44.75 | 35.92 | 34.59 | 76.97 | 51.27 | 48.75 |
| Diesel fuel (distillate fuel oil)[6] | 26.15 | 32.63 | 30.68 | 30.29 | 52.95 | 42.52 | 40.75 | 87.80 | 59.50 | 56.33 |
| Residual fuel oil | 17.83 | 18.18 | 17.19 | 17.02 | 31.48 | 25.31 | 24.28 | 55.18 | 37.06 | 34.59 |
| Natural gas[7] | 16.14 | 20.21 | 19.46 | 19.64 | 31.55 | 26.08 | 25.42 | 49.62 | 34.98 | 32.95 |
| Electricity | 32.77 | 36.36 | 34.13 | 34.22 | 53.57 | 43.51 | 42.52 | 83.64 | 57.88 | 54.52 |
| **Electric power**[8] | | | | | | | | | | |
| Distillate fuel oil | 23.30 | 27.20 | 25.89 | 25.67 | 45.54 | 36.98 | 35.73 | 77.51 | 52.87 | 50.33 |
| Residual fuel oil | 15.97 | 30.62 | 28.76 | 28.38 | 51.00 | 40.52 | 38.59 | 85.47 | 57.01 | 52.31 |
| Natural gas | 4.77 | 5.64 | 5.65 | 6.01 | 9.99 | 8.35 | 8.62 | 19.73 | 13.83 | 13.01 |
| Steam coal | 2.38 | 3.06 | 2.90 | 2.89 | 4.93 | 3.96 | 3.78 | 7.86 | 5.28 | 4.84 |

## Table B3. Energy prices by sector and source (continued)

(nominal dollars per million Btu, unless otherwise noted)

| Sector and source | 2011 | Projections 2020 Low economic growth | 2020 Reference | 2020 High economic growth | 2030 Low economic growth | 2030 Reference | 2030 High economic growth | 2040 Low economic growth | 2040 Reference | 2040 High economic growth |
|---|---|---|---|---|---|---|---|---|---|---|
| **Average price to all users[9]** | | | | | | | | | | |
| Propane | 17.13 | 15.94 | 15.78 | 16.32 | 30.33 | 25.03 | 25.09 | 57.18 | 39.26 | 37.06 |
| E85[3] | 25.30 | 35.44 | 34.18 | 33.89 | 47.99 | 37.18 | 37.02 | 79.96 | 50.46 | 49.62 |
| Motor gasoline[4] | 28.47 | 34.24 | 32.10 | 31.77 | 52.97 | 42.40 | 40.51 | 88.13 | 59.70 | 56.17 |
| Jet fuel[5] | 22.49 | 26.21 | 24.79 | 24.54 | 44.75 | 35.92 | 34.59 | 76.97 | 51.27 | 48.75 |
| Distillate fuel oil | 26.18 | 32.17 | 30.27 | 29.89 | 52.35 | 42.07 | 40.35 | 86.98 | 58.97 | 55.83 |
| Residual fuel oil | 17.65 | 19.45 | 18.41 | 18.25 | 33.55 | 27.03 | 25.93 | 58.78 | 39.53 | 36.84 |
| Natural gas | 6.68 | 8.37 | 8.16 | 8.44 | 14.04 | 11.41 | 11.42 | 26.01 | 18.06 | 17.42 |
| Metallurgical coal | 7.01 | 10.94 | 10.09 | 9.83 | 17.78 | 13.92 | 13.12 | 27.68 | 18.34 | 16.76 |
| Other coal | 2.45 | 3.14 | 2.97 | 2.95 | 5.02 | 4.03 | 3.84 | 8.00 | 5.37 | 4.92 |
| Coal to liquids | - - | - - | - - | 2.37 | - - | 3.52 | 3.36 | 7.28 | 4.87 | 4.30 |
| Electricity | 29.03 | 34.59 | 31.71 | 31.41 | 49.24 | 39.20 | 37.96 | 76.55 | 52.12 | 48.63 |
| **Non-renewable energy expenditures by sector (billion nominal dollars)** | | | | | | | | | | |
| Residential | 248.08 | 295.03 | 280.71 | 286.39 | 441.11 | 374.04 | 387.49 | 707.41 | 527.54 | 552.03 |
| Commercial | 179.97 | 223.21 | 209.48 | 209.95 | 345.35 | 281.23 | 276.49 | 589.66 | 411.95 | 395.67 |
| Industrial | 225.18 | 290.58 | 298.68 | 323.30 | 444.67 | 407.07 | 437.25 | 743.64 | 583.76 | 636.70 |
| Transportation | 718.25 | 819.97 | 801.07 | 817.92 | 1,179.60 | 1,034.13 | 1,059.28 | 1,956.18 | 1,486.52 | 1,562.18 |
| Total non-renewable expenditures | 1,371.48 | 1,628.79 | 1,589.94 | 1,637.57 | 2,410.74 | 2,096.47 | 2,160.51 | 3,996.88 | 3,009.77 | 3,146.58 |
| Transportation renewable expenditures | 1.24 | 3.34 | 2.81 | 2.83 | 13.28 | 6.06 | 5.62 | 21.08 | 8.33 | 10.74 |
| **Total expenditures** | **1,372.71** | **1,632.13** | **1,592.75** | **1,640.40** | **2,424.02** | **2,102.52** | **2,166.12** | **4,017.96** | **3,018.11** | **3,157.32** |

[1]Includes energy for combined heat and power plants that have a non-regulatory status, and small on-site generating systems.
[2]Excludes use for lease and plant fuel.
[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]Kerosene-type jet fuel. Includes Federal and State taxes while excluding county and local taxes.
[6]Diesel fuel for on-road use. Includes Federal and State taxes while excluding county and local taxes.
[7]Natural gas used as a vehicle fuel. Includes estimated motor vehicle fuel taxes and estimated dispensing costs or charges.
[8]Includes electricity-only and combined heat and power plants that have a regulatory status.
[9]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 2011 are model results and may differ slightly from official EIA data reports.
**Sources:** 2011 prices for motor gasoline, distillate fuel oil, and jet fuel are based on prices in the U.S. Energy Information Administration (EIA), (2012/08) (Washington, DC, August 2012). 2011 residential, commercial, and industrial natural gas delivered prices: EIA, *Natural Gas Monthly*, DOE/EIA-0130(2012/07) (Washington, DC, July 2012). 2011 transportation sector natural gas delivered prices are model results. 2011 electric power sector distillate and residual fuel oil prices: EIA, *Monthly Energy Review*, DOE/EIA-0035(2012/09) (Washington, DC, September 2012). 2011 electric power sector natural gas prices: EIA, *Electric Power Monthly*, DOE/EIA-0226, April 2011 and April 2012, Table 4.2, and EIA, *State Energy Data Report 2010*, DOE/EIA-0214(2010) (Washington, DC, June 2012). 2011 coal prices based on: EIA, (2011/4Q) (Washington, DC, March 2012) and EIA, AEO2013 National Energy Modeling System run REF2013.D102312A. 2011 electricity prices: EIA, *Annual Energy Review 2011*, DOE/EIA-0384(2011) (Washington, DC, September 2012). 2011 E85 prices derived from monthly prices in the Clean Cities Alternative Fuel Price Report. **Projections:** EIA, AEO2013 National Energy Modeling System runs LOWMACRO.D110912A, REF2013.D102312A, and HIGHMACRO.D110912A.

## Table B4. Macroeconomic indicators
(billion 2005 chain-weighted dollars, unless otherwise noted)

| Indicators | 2011 | Projections 2020 Low economic growth | 2020 Reference | 2020 High economic growth | 2030 Low economic growth | 2030 Reference | 2030 High economic growth | 2040 Low economic growth | 2040 Reference | 2040 High economic growth |
|---|---|---|---|---|---|---|---|---|---|---|
| **Real gross domestic product** | **13,299** | **15,717** | **16,859** | **17,754** | **18,703** | **21,355** | **23,232** | **23,283** | **27,277** | **30,552** |
| **Components of real gross domestic product** | | | | | | | | | | |
| Real consumption | 9,429 | 10,836 | 11,528 | 12,113 | 12,482 | 14,243 | 15,541 | 14,836 | 17,917 | 20,161 |
| Real investment | 1,744 | 2,530 | 2,909 | 3,335 | 3,363 | 3,914 | 4,504 | 4,776 | 5,409 | 6,269 |
| Real government spending | 2,524 | 2,358 | 2,446 | 2,512 | 2,442 | 2,659 | 2,777 | 2,620 | 2,980 | 3,172 |
| Real exports | 1,777 | 2,896 | 3,016 | 3,102 | 4,789 | 5,214 | 5,652 | 7,650 | 8,357 | 9,553 |
| Real imports | 2,185 | 2,817 | 2,927 | 3,163 | 4,089 | 4,311 | 4,806 | 5,847 | 6,518 | 7,531 |
| **Energy intensity (thousand Btu per 2005 dollar of GDP)** | | | | | | | | | | |
| Delivered energy | 5.34 | 4.52 | 4.39 | 4.33 | 3.68 | 3.48 | 3.41 | 3.01 | 2.85 | 2.81 |
| Total energy | 7.35 | 6.17 | 5.99 | 5.90 | 5.12 | 4.81 | 4.70 | 4.20 | 3.95 | 3.91 |
| **Price indices** | | | | | | | | | | |
| GDP chain-type price index (2005=1.000) | 1.134 | 1.408 | 1.307 | 1.275 | 1.991 | 1.564 | 1.469 | 2.847 | 1.871 | 1.678 |
| Consumer price index (1982-4=1) | | | | | | | | | | |
| All-urban | 2.25 | 2.86 | 2.66 | 2.59 | 4.13 | 3.27 | 3.07 | 6.09 | 4.04 | 3.64 |
| Energy commodities and services | 2.44 | 2.90 | 2.70 | 2.67 | 4.42 | 3.53 | 3.39 | 7.18 | 4.86 | 4.57 |
| Wholesale price index (1982=1.00) | | | | | | | | | | |
| All commodities | 2.01 | 2.39 | 2.22 | 2.21 | 3.31 | 2.59 | 2.48 | 4.73 | 3.10 | 2.88 |
| Fuel and power | 2.16 | 2.63 | 2.48 | 2.50 | 4.18 | 3.38 | 3.30 | 7.17 | 4.90 | 4.65 |
| Metals and metal products | 2.26 | 2.68 | 2.52 | 2.62 | 3.53 | 2.83 | 2.83 | 4.63 | 3.16 | 3.22 |
| Industrial commodities excluding energy | 1.93 | 2.30 | 2.12 | 2.11 | 3.02 | 2.34 | 2.22 | 4.01 | 2.57 | 2.37 |
| **Interest rates (percent, nominal)** | | | | | | | | | | |
| Federal funds rate | 0.10 | 5.52 | 4.04 | 3.50 | 6.97 | 3.97 | 3.29 | 7.11 | 3.74 | 3.04 |
| 10-year treasury note | 2.79 | 7.36 | 4.88 | 4.09 | 7.69 | 4.95 | 4.17 | 7.72 | 4.86 | 4.06 |
| AA utility bond rate | 4.78 | 9.84 | 6.91 | 5.57 | 10.47 | 7.21 | 5.77 | 10.90 | 7.39 | 5.53 |
| **Value of shipments (billion 2005 dollars)** | | | | | | | | | | |
| Service sectors | 21,168 | 24,814 | 26,492 | 28,005 | 29,028 | 32,624 | 35,626 | 33,484 | 38,529 | 43,296 |
| Total industrial | 6,019 | 7,136 | 7,894 | 8,633 | 7,721 | 9,087 | 10,325 | 8,909 | 10,616 | 12,730 |
| Agriculture, mining, and construction | 1,582 | 1,937 | 2,211 | 2,535 | 1,986 | 2,375 | 2,775 | 2,239 | 2,644 | 3,099 |
| Manufacturing | 4,438 | 5,199 | 5,683 | 6,099 | 5,736 | 6,712 | 7,550 | 6,670 | 7,972 | 9,631 |
| Energy-intensive | 1,615 | 1,783 | 1,893 | 1,992 | 1,817 | 2,027 | 2,182 | 1,891 | 2,144 | 2,394 |
| Non-energy-intensive | 2,823 | 3,416 | 3,790 | 4,106 | 3,919 | 4,685 | 5,368 | 4,779 | 5,828 | 7,237 |
| **Total shipments** | **27,187** | **31,950** | **34,385** | **36,639** | **36,749** | **41,711** | **45,951** | **42,393** | **49,145** | **56,026** |
| **Population and employment (millions)** | | | | | | | | | | |
| Population with armed forces overseas | 312.4 | 338.2 | 340.5 | 342.9 | 367.1 | 372.4 | 378.7 | 395.2 | 404.4 | 415.4 |
| Population, aged 16 and over | 247.0 | 268.0 | 269.5 | 271.3 | 292.3 | 296.3 | 300.9 | 316.0 | 322.9 | 331.0 |
| Population, over age 65 | 41.6 | 55.0 | 55.4 | 55.5 | 72.1 | 72.7 | 73.0 | 81.1 | 81.8 | 82.6 |
| Employment, nonfarm | 131.3 | 146.6 | 149.2 | 153.3 | 156.5 | 160.8 | 165.7 | 167.1 | 174.0 | 182.5 |
| Employment, manufacturing | 11.7 | 11.8 | 12.4 | 13.0 | 10.4 | 11.2 | 12.2 | 9.3 | 9.9 | 11.3 |
| **Key labor indicators** | | | | | | | | | | |
| Labor force (millions) | 153.6 | 163.8 | 164.7 | 166.1 | 172.5 | 174.9 | 178.1 | 186.2 | 190.7 | 196.1 |
| Non-farm labor productivity (1992=1.00) | 1.10 | 1.20 | 1.25 | 1.28 | 1.40 | 1.54 | 1.60 | 1.66 | 1.88 | 1.99 |
| Unemployment rate (percent) | 8.95 | 5.93 | 5.49 | 5.02 | 5.47 | 5.32 | 5.08 | 5.42 | 5.24 | 4.96 |
| **Key indicators for energy demand** | | | | | | | | | | |
| Real disposable personal income | 10,150 | 12,097 | 12,655 | 13,209 | 14,637 | 15,948 | 17,001 | 17,912 | 19,785 | 21,416 |
| Housing starts (millions) | 0.66 | 1.38 | 1.89 | 2.59 | 1.25 | 1.89 | 2.74 | 1.25 | 1.89 | 2.89 |
| Commercial floorspace (billion square feet) | 81.7 | 88.5 | 89.1 | 89.7 | 96.3 | 98.1 | 100.0 | 105.4 | 108.8 | 112.3 |
| Unit sales of light-duty vehicles (millions) | 12.73 | 15.39 | 16.85 | 18.12 | 15.08 | 17.74 | 19.13 | 15.40 | 19.21 | 21.87 |

GDP = Gross domestic product.
Btu = British thermal unit.
**Sources:** 2011: IHS Global Insight, Global Insight Industry and Employment models, August 2012. **Projections:** U.S. Energy Information Administration, AEO2013 National Energy Modeling System runs LOWMACRO.D110912A, REF2013.D102312A, and HIGHMACRO.D110912A.

# Price case comparisons

## Table C1. Total energy supply, disposition, and price summary
(quadrillion Btu per year, unless otherwise noted)

| Supply, disposition, and prices | 2011 | Projections | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | | 2020 | | | 2030 | | | 2040 | | |
| | | 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 | 12.16 | 15.22 | 15.95 | 16.61 | 11.89 | 13.47 | 15.07 | 9.99 | 13.12 | 14.63 |
| Natural gas plant liquids | 2.88 | 3.98 | 4.14 | 4.24 | 3.79 | 3.85 | 3.99 | 3.69 | 3.89 | 4.08 |
| Dry natural gas | 23.51 | 26.44 | 27.19 | 27.61 | 28.09 | 30.44 | 31.87 | 30.91 | 33.87 | 36.61 |
| Coal[1] | 22.21 | 22.13 | 21.74 | 21.43 | 23.15 | 23.25 | 22.76 | 24.28 | 23.54 | 23.34 |
| Nuclear / uranium[2] | 8.26 | 9.25 | 9.25 | 9.25 | 9.49 | 9.49 | 9.53 | 9.14 | 9.44 | 10.63 |
| Hydropower | 3.17 | 2.83 | 2.83 | 2.83 | 2.86 | 2.87 | 2.88 | 2.91 | 2.92 | 2.92 |
| Biomass[3] | 4.05 | 4.85 | 5.00 | 4.95 | 5.27 | 5.42 | 5.48 | 6.57 | 6.96 | 7.66 |
| Other renewable energy[4] | 1.58 | 2.24 | 2.22 | 2.21 | 2.47 | 2.50 | 2.54 | 3.59 | 3.84 | 4.16 |
| Other[5] | 1.20 | 0.83 | 0.83 | 0.84 | 0.95 | 0.88 | 0.85 | 0.97 | 0.89 | 0.80 |
| **Total** | **79.02** | **87.78** | **89.16** | **89.97** | **87.96** | **92.18** | **94.96** | **92.06** | **98.46** | **104.83** |
| **Imports** | | | | | | | | | | |
| Crude oil | 19.46 | 16.52 | 15.02 | 13.35 | 19.35 | 16.33 | 13.28 | 22.55 | 16.89 | 13.07 |
| Liquid fuels and other petroleum[6] | 5.24 | 6.24 | 5.55 | 5.02 | 6.31 | 5.33 | 4.31 | 6.73 | 4.82 | 3.75 |
| Natural gas[7] | 3.54 | 2.98 | 2.58 | 2.42 | 3.44 | 2.63 | 2.49 | 2.90 | 2.01 | 1.88 |
| Other imports[8] | 0.43 | 0.11 | 0.11 | 0.36 | 0.03 | 0.13 | 0.89 | 0.24 | 0.84 | 1.21 |
| **Total** | **28.66** | **25.85** | **23.26** | **21.16** | **29.13** | **24.41** | **20.96** | **32.42** | **24.55** | **19.91** |
| **Exports** | | | | | | | | | | |
| Liquid fuels and other petroleum[9] | 6.08 | 5.40 | 5.37 | 5.30 | 5.41 | 5.25 | 5.14 | 5.87 | 5.71 | 5.57 |
| Natural gas[10] | 1.52 | 2.67 | 2.67 | 2.66 | 3.53 | 4.71 | 5.27 | 4.63 | 5.56 | 7.82 |
| Coal | 2.75 | 3.17 | 3.13 | 3.07 | 3.55 | 3.51 | 3.45 | 4.08 | 3.79 | 3.41 |
| **Total** | **10.35** | **11.24** | **11.17** | **11.03** | **12.48** | **13.47** | **13.86** | **14.59** | **15.06** | **16.80** |
| **Discrepancy[11]** | **-0.36** | **0.24** | **0.21** | **0.22** | **0.44** | **0.30** | **0.20** | **0.58** | **0.32** | **0.21** |
| **Consumption** | | | | | | | | | | |
| Liquid fuels and other petroleum[12] | 37.02 | 38.62 | 37.54 | 36.21 | 37.84 | 36.08 | 34.04 | 39.34 | 36.07 | 33.77 |
| Natural gas | 24.91 | 26.56 | 26.77 | 27.04 | 27.80 | 27.95 | 28.66 | 28.97 | 29.83 | 30.01 |
| Coal[13] | 19.66 | 18.93 | 18.59 | 18.50 | 19.54 | 19.70 | 19.94 | 20.32 | 20.35 | 20.71 |
| Nuclear / uranium[2] | 8.26 | 9.25 | 9.25 | 9.25 | 9.49 | 9.49 | 9.53 | 9.14 | 9.44 | 10.63 |
| Hydropower | 3.17 | 2.83 | 2.83 | 2.83 | 2.86 | 2.87 | 2.88 | 2.91 | 2.92 | 2.92 |
| Biomass[14] | 2.74 | 3.42 | 3.53 | 3.53 | 3.90 | 3.94 | 3.99 | 4.74 | 4.91 | 5.21 |
| Other renewable energy[4] | 1.58 | 2.24 | 2.22 | 2.21 | 2.47 | 2.50 | 2.54 | 3.59 | 3.84 | 4.16 |
| Other[15] | 0.35 | 0.31 | 0.31 | 0.31 | 0.26 | 0.28 | 0.28 | 0.29 | 0.29 | 0.31 |
| **Total** | **97.70** | **102.16** | **101.04** | **99.88** | **104.17** | **102.81** | **101.86** | **109.32** | **107.64** | **107.73** |
| **Prices (2011 dollars per unit)** | | | | | | | | | | |
| Crude oil spot prices (dollars per barrel) | | | | | | | | | | |
| Brent | 111.26 | 68.90 | 105.57 | 155.28 | 71.90 | 130.47 | 191.90 | 74.90 | 162.68 | 237.16 |
| West Texas Intermediate | 94.86 | 66.90 | 103.57 | 153.28 | 69.90 | 128.47 | 189.90 | 72.90 | 160.68 | 235.16 |
| Natural gas at Henry Hub (dollars per million Btu) | 3.98 | 4.08 | 4.13 | 4.33 | 5.15 | 5.40 | 6.03 | 7.06 | 7.83 | 8.96 |
| Coal (dollars per ton) at the minemouth[16] | 41.16 | 47.84 | 49.26 | 50.56 | 53.51 | 55.64 | 57.33 | 58.08 | 61.28 | 64.50 |
| Coal (dollars per million Btu) | | | | | | | | | | |
| at the minemouth[16] | 2.04 | 2.39 | 2.45 | 2.52 | 2.68 | 2.79 | 2.87 | 2.92 | 3.08 | 3.22 |
| Average end-use[17] | 2.57 | 2.66 | 2.77 | 2.89 | 2.93 | 3.10 | 3.24 | 3.19 | 3.42 | 3.61 |
| Average electricity (cents per kilowatthour) | 9.9 | 9.3 | 9.4 | 9.5 | 9.5 | 9.7 | 10.0 | 10.3 | 10.8 | 11.3 |

## Table C1. Total energy supply, disposition, and price summary (continued)
(quadrillion Btu per year, unless otherwise noted)

| Supply, disposition, and prices | 2011 | Projections | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | | 2020 | | | 2030 | | | 2040 | | |
| | | 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)** | | | | | | | | | | |
| Crude oil spot prices (dollars per barrel) | | | | | | | | | | |
| Brent | 111.26 | 79.61 | 121.73 | 177.97 | 100.62 | 180.04 | 260.76 | 127.14 | 268.50 | 382.50 |
| West Texas Intermediate | 94.86 | 77.30 | 119.43 | 175.68 | 97.82 | 177.28 | 258.04 | 123.74 | 265.20 | 379.28 |
| Natural gas at Henry Hub | | | | | | | | | | |
| (dollars per million Btu) | 3.98 | 4.71 | 4.77 | 4.97 | 7.21 | 7.45 | 8.20 | 11.98 | 12.92 | 14.46 |
| Coal (dollars per ton) | | | | | | | | | | |
| at the minemouth[16] | 41.16 | 55.27 | 56.81 | 57.95 | 74.88 | 76.78 | 77.90 | 98.60 | 101.14 | 104.03 |
| Coal (dollars per million Btu) | | | | | | | | | | |
| at the minemouth[16] | 2.04 | 2.76 | 2.83 | 2.88 | 3.76 | 3.85 | 3.90 | 4.96 | 5.08 | 5.20 |
| Average end-use[17] | 2.57 | 3.08 | 3.19 | 3.31 | 4.10 | 4.28 | 4.41 | 5.42 | 5.65 | 5.83 |
| Average electricity (cents per kilowatthour) | 9.9 | 10.7 | 10.8 | 10.9 | 13.3 | 13.4 | 13.6 | 17.5 | 17.8 | 18.3 |

[1]Includes waste coal.
[2]These values represent the energy obtained from uranium when it is used in light water reactors. The total energy content of uranium is much larger, but alternative processes are required to take advantage of it.
[3]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.
[4]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 data.
[5]Includes non-biogenic municipal waste, liquid hydrogen, methanol, and some domestic inputs to refineries.
[6]Includes imports of finished petroleum products, unfinished oils, alcohols, ethers, blending components, and renewable fuels such as ethanol.
[7]Includes imports of liquefied natural gas that are later re-exported.
[8]Includes coal, coal coke (net), and electricity (net). Excludes imports of fuel used in nuclear power plants.
[9]Includes crude oil, petroleum products, ethanol, and biodiesel.
[10]Includes re-exported liquefied natural gas.
[11]Balancing item. Includes unaccounted for supply, losses, gains, and net storage withdrawals.
[12]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.
[13]Excludes coal converted to coal-based synthetic liquids and natural gas.
[14]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.
[15]Includes non-biogenic municipal waste, liquid hydrogen, and net electricity imports.
[16]Includes reported prices for both open market and captive mines. Prices weighted by production, which differs from average minemouth prices published in EIA data reports where it is weighted by reported sales.
[17]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 2011 are model results and may differ slightly from official EIA data reports.
**Sources:** 2011 natural gas supply values: U.S. Energy Information Administration (EIA), *Natural Gas Monthly*, DOE/EIA-0130(2012/07) (Washington, DC, July 2012). 2011 natural gas spot price at Henry Hub based on daily data from Natural Gas Intelligence. 2011 coal minemouth and delivered coal prices: EIA, *Annual Coal Report 2011*, DOE/EIA-0584(2011) (Washington, DC, November 2012). 2011 petroleum supply values: EIA, *Petroleum Supply Annual 2011*, DOE/EIA-0340(2011)/1 (Washington, DC, August 2012). 2011 crude oil spot prices: Thomson Reuters. Other 2011 coal values: *Quarterly Coal Report, October-December 2011*, DOE/EIA-0121(2011/4Q) (Washington, DC, March 2012). Other 2011 values: EIA, *Annual Energy Review 2011*, DOE/EIA-0384(2011) (Washington, DC, September 2012). **Projections:** EIA, AEO2013 National Energy Modeling System runs LOWPRICE.D031213A, REF2013.D102312A, and HIGHPRICE.D110912A.

# Table C2. Energy consumption by sector and source
(quadrillion Btu per year, unless otherwise noted)

| Sector and source | 2011 | Projections | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | | 2020 | | | 2030 | | | 2040 | | |
| | | Low oil price | Reference | High oil price | Low oil price | Reference | High oil price | Low oil price | Reference | High oil price |
| **Energy consumption** | | | | | | | | | | |
| **Residential** | | | | | | | | | | |
| Propane | 0.53 | 0.53 | 0.52 | 0.52 | 0.53 | 0.52 | 0.51 | 0.54 | 0.52 | 0.51 |
| Kerosene | 0.02 | 0.02 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 |
| Distillate fuel oil | 0.59 | 0.54 | 0.51 | 0.48 | 0.44 | 0.40 | 0.37 | 0.37 | 0.32 | 0.30 |
| Liquid fuels and other petroleum subtotal | 1.14 | 1.08 | 1.05 | 1.01 | 0.98 | 0.93 | 0.89 | 0.92 | 0.86 | 0.82 |
| Natural gas | 4.83 | 4.64 | 4.62 | 4.61 | 4.48 | 4.46 | 4.42 | 4.27 | 4.23 | 4.17 |
| Coal | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.00 | 0.00 | 0.00 |
| Renewable energy[1] | 0.45 | 0.37 | 0.44 | 0.50 | 0.36 | 0.45 | 0.52 | 0.34 | 0.45 | 0.53 |
| Electricity | 4.86 | 4.87 | 4.84 | 4.81 | 5.41 | 5.36 | 5.31 | 6.13 | 6.03 | 5.93 |
| **Delivered energy** | **11.28** | **10.97** | **10.95** | **10.94** | **11.23** | **11.20** | **11.15** | **11.67** | **11.57** | **11.46** |
| Electricity related losses | 10.20 | 9.73 | 9.66 | 9.59 | 10.52 | 10.45 | 10.39 | 11.60 | 11.50 | 11.56 |
| **Total** | **21.48** | **20.70** | **20.62** | **20.52** | **21.75** | **21.65** | **21.54** | **23.27** | **23.08** | **23.02** |
| **Commercial** | | | | | | | | | | |
| Propane | 0.14 | 0.16 | 0.16 | 0.15 | 0.18 | 0.16 | 0.16 | 0.19 | 0.17 | 0.16 |
| Motor gasoline[2] | 0.05 | 0.06 | 0.05 | 0.05 | 0.06 | 0.06 | 0.05 | 0.07 | 0.06 | 0.06 |
| Kerosene | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 0.00 | 0.00 | 0.01 | 0.01 | 0.00 |
| Distillate fuel oil | 0.42 | 0.38 | 0.34 | 0.31 | 0.37 | 0.32 | 0.29 | 0.37 | 0.30 | 0.27 |
| Residual fuel oil | 0.07 | 0.12 | 0.09 | 0.08 | 0.12 | 0.09 | 0.07 | 0.13 | 0.09 | 0.07 |
| Liquid fuels and other petroleum subtotal | 0.69 | 0.72 | 0.65 | 0.60 | 0.73 | 0.64 | 0.58 | 0.76 | 0.63 | 0.56 |
| Natural gas | 3.23 | 3.41 | 3.40 | 3.38 | 3.52 | 3.50 | 3.46 | 3.72 | 3.68 | 3.60 |
| Coal | 0.05 | 0.05 | 0.05 | 0.05 | 0.05 | 0.05 | 0.05 | 0.05 | 0.05 | 0.05 |
| Renewable energy[3] | 0.13 | 0.13 | 0.13 | 0.13 | 0.13 | 0.13 | 0.13 | 0.13 | 0.13 | 0.13 |
| Electricity | 4.50 | 4.73 | 4.72 | 4.70 | 5.26 | 5.22 | 5.18 | 5.79 | 5.72 | 5.64 |
| **Delivered energy** | **8.60** | **9.04** | **8.95** | **8.85** | **9.69** | **9.54** | **9.39** | **10.45** | **10.21** | **9.98** |
| Electricity related losses | 9.45 | 9.46 | 9.42 | 9.37 | 10.22 | 10.18 | 10.15 | 10.96 | 10.92 | 11.00 |
| **Total** | **18.05** | **18.50** | **18.37** | **18.23** | **19.91** | **19.72** | **19.54** | **21.42** | **21.13** | **20.97** |
| **Industrial[4]** | | | | | | | | | | |
| Liquefied petroleum gases | 2.10 | 2.37 | 2.46 | 2.52 | 2.32 | 2.47 | 2.50 | 2.21 | 2.30 | 2.31 |
| Propylene | 0.40 | 0.58 | 0.56 | 0.52 | 0.56 | 0.52 | 0.49 | 0.50 | 0.46 | 0.46 |
| Motor gasoline[2] | 0.27 | 0.32 | 0.32 | 0.32 | 0.33 | 0.32 | 0.31 | 0.34 | 0.32 | 0.31 |
| Distillate fuel oil | 1.21 | 1.27 | 1.22 | 1.20 | 1.28 | 1.18 | 1.13 | 1.37 | 1.22 | 1.16 |
| Residual fuel oil | 0.11 | 0.12 | 0.11 | 0.10 | 0.12 | 0.11 | 0.10 | 0.13 | 0.11 | 0.10 |
| Petrochemical feedstocks | 0.88 | 1.09 | 1.03 | 1.02 | 1.15 | 1.08 | 1.08 | 1.15 | 1.09 | 1.09 |
| Other petroleum[5] | 3.61 | 3.79 | 3.54 | 3.37 | 3.79 | 3.46 | 3.29 | 4.11 | 3.65 | 3.42 |
| Liquid fuels and other petroleum subtotal | 8.57 | 9.53 | 9.25 | 9.05 | 9.56 | 9.14 | 8.89 | 9.79 | 9.16 | 8.85 |
| Natural gas | 6.92 | 7.79 | 7.86 | 7.90 | 7.94 | 7.97 | 7.90 | 8.04 | 8.08 | 8.01 |
| Natural-gas-to-liquids heat and power | 0.00 | 0.00 | 0.13 | 0.15 | 0.00 | 0.21 | 0.28 | 0.00 | 0.33 | 0.53 |
| Lease and plant fuel[6] | 1.42 | 1.53 | 1.57 | 1.62 | 1.56 | 1.73 | 2.00 | 1.64 | 1.97 | 2.49 |
| Natural gas subtotal | 8.34 | 9.32 | 9.56 | 9.67 | 9.50 | 9.91 | 10.18 | 9.68 | 10.38 | 11.03 |
| Metallurgical coal | 0.56 | 0.61 | 0.60 | 0.59 | 0.52 | 0.52 | 0.52 | 0.46 | 0.46 | 0.47 |
| Other industrial coal | 1.04 | 1.00 | 1.00 | 1.00 | 1.00 | 1.00 | 1.00 | 1.05 | 1.05 | 1.05 |
| Coal-to-liquids heat and power | 0.00 | 0.00 | 0.00 | 0.11 | 0.00 | 0.09 | 0.21 | 0.00 | 0.15 | 0.39 |
| Net coal coke imports | 0.01 | -0.01 | -0.01 | -0.01 | -0.04 | -0.04 | -0.04 | -0.05 | -0.05 | -0.05 |
| Coal subtotal | 1.62 | 1.60 | 1.58 | 1.69 | 1.48 | 1.57 | 1.69 | 1.46 | 1.61 | 1.86 |
| Biofuels heat and coproducts | 0.67 | 0.82 | 0.82 | 0.80 | 0.86 | 0.85 | 0.87 | 1.27 | 1.37 | 1.64 |
| Renewable energy[7] | 1.51 | 1.73 | 1.72 | 1.70 | 2.03 | 1.97 | 1.91 | 2.39 | 2.28 | 2.20 |
| Electricity | 3.33 | 4.00 | 3.95 | 3.90 | 4.00 | 3.96 | 3.92 | 3.93 | 3.91 | 3.90 |
| **Delivered energy** | **24.04** | **27.01** | **26.87** | **26.80** | **27.43** | **27.40** | **27.44** | **28.52** | **28.71** | **29.48** |
| Electricity related losses | 6.99 | 7.99 | 7.89 | 7.78 | 7.78 | 7.72 | 7.66 | 7.44 | 7.45 | 7.60 |
| **Total** | **31.03** | **35.00** | **34.76** | **34.58** | **35.21** | **35.11** | **35.11** | **35.96** | **36.16** | **37.08** |

## Table C2. Energy consumption by sector and source (continued)

(quadrillion Btu per year, unless otherwise noted)

| Sector and source | 2011 | Projections 2020 Low oil price | 2020 Reference | 2020 High oil price | 2030 Low oil price | 2030 Reference | 2030 High oil price | 2040 Low oil price | 2040 Reference | 2040 High oil price |
|---|---|---|---|---|---|---|---|---|---|---|
| **Transportation** | | | | | | | | | | |
| Propane | 0.06 | 0.05 | 0.06 | 0.07 | 0.05 | 0.07 | 0.08 | 0.06 | 0.08 | 0.10 |
| E85[8] | 0.05 | 0.06 | 0.08 | 0.11 | 0.13 | 0.16 | 0.34 | 0.15 | 0.17 | 0.61 |
| Motor gasoline[2] | 16.31 | 15.50 | 14.88 | 14.16 | 13.91 | 13.06 | 12.21 | 13.85 | 12.64 | 11.51 |
| Jet fuel[9] | 3.01 | 3.12 | 3.11 | 3.10 | 3.29 | 3.28 | 3.28 | 3.43 | 3.42 | 3.41 |
| Distillate fuel oil[10] | 5.91 | 7.38 | 7.28 | 6.95 | 7.98 | 7.61 | 6.58 | 9.16 | 7.90 | 6.68 |
| Residual fuel oil | 0.82 | 0.84 | 0.84 | 0.84 | 0.85 | 0.86 | 0.86 | 0.87 | 0.87 | 0.87 |
| Other petroleum[11] | 0.17 | 0.15 | 0.15 | 0.15 | 0.16 | 0.16 | 0.16 | 0.16 | 0.16 | 0.16 |
| Liquid fuels and other petroleum subtotal | 26.32 | 27.11 | 26.42 | 25.39 | 26.38 | 25.20 | 23.51 | 27.67 | 25.24 | 23.35 |
| Pipeline fuel natural gas | 0.70 | 0.71 | 0.71 | 0.72 | 0.72 | 0.74 | 0.76 | 0.74 | 0.78 | 0.81 |
| Compressed / liquefied natural gas | 0.04 | 0.06 | 0.08 | 0.35 | 0.07 | 0.26 | 1.24 | 0.09 | 1.05 | 2.24 |
| 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 | 0.04 | 0.04 | 0.05 | 0.05 | 0.07 | 0.08 |
| **Delivered energy** | **27.09** | **27.91** | **27.24** | **26.49** | **27.21** | **26.25** | **25.57** | **28.56** | **27.14** | **26.49** |
| Electricity related losses | 0.05 | 0.06 | 0.06 | 0.06 | 0.08 | 0.09 | 0.10 | 0.10 | 0.13 | 0.16 |
| **Total** | **27.13** | **27.97** | **27.30** | **26.56** | **27.29** | **26.33** | **25.67** | **28.67** | **27.27** | **26.66** |
| **Delivered energy consumption for all sectors** | | | | | | | | | | |
| Liquefied petroleum gases | 2.82 | 3.11 | 3.21 | 3.26 | 3.08 | 3.23 | 3.25 | 2.99 | 3.08 | 3.08 |
| Propylene | 0.40 | 0.58 | 0.56 | 0.52 | 0.56 | 0.52 | 0.49 | 0.50 | 0.46 | 0.46 |
| E85[8] | 0.05 | 0.06 | 0.08 | 0.11 | 0.13 | 0.16 | 0.34 | 0.15 | 0.17 | 0.61 |
| Motor gasoline[2] | 16.64 | 15.88 | 15.26 | 14.53 | 14.30 | 13.43 | 12.57 | 14.26 | 13.03 | 11.87 |
| Jet fuel[9] | 3.01 | 3.12 | 3.11 | 3.10 | 3.29 | 3.28 | 3.28 | 3.43 | 3.42 | 3.41 |
| Kerosene | 0.03 | 0.03 | 0.03 | 0.02 | 0.03 | 0.02 | 0.02 | 0.03 | 0.02 | 0.02 |
| Distillate fuel oil | 8.12 | 9.57 | 9.35 | 8.94 | 10.08 | 9.51 | 8.37 | 11.27 | 9.74 | 8.41 |
| Residual fuel oil | 1.01 | 1.08 | 1.05 | 1.02 | 1.10 | 1.05 | 1.03 | 1.12 | 1.07 | 1.05 |
| Petrochemical feedstocks | 0.88 | 1.09 | 1.03 | 1.02 | 1.15 | 1.08 | 1.08 | 1.15 | 1.09 | 1.09 |
| Other petroleum[12] | 3.77 | 3.93 | 3.69 | 3.52 | 3.94 | 3.61 | 3.44 | 4.26 | 3.80 | 3.58 |
| Liquid fuels and other petroleum subtotal | 36.72 | 38.44 | 37.37 | 36.04 | 37.66 | 35.90 | 33.86 | 39.15 | 35.88 | 33.59 |
| Natural gas | 15.03 | 15.90 | 15.95 | 16.25 | 16.01 | 16.19 | 17.02 | 16.12 | 17.05 | 18.03 |
| Natural-gas-to-liquids heat and power | 0.00 | 0.00 | 0.13 | 0.15 | 0.00 | 0.21 | 0.28 | 0.00 | 0.33 | 0.53 |
| Lease and plant fuel[6] | 1.42 | 1.53 | 1.57 | 1.62 | 1.56 | 1.73 | 2.00 | 1.64 | 1.97 | 2.49 |
| Pipeline natural gas | 0.70 | 0.71 | 0.71 | 0.72 | 0.72 | 0.74 | 0.76 | 0.74 | 0.78 | 0.81 |
| Natural gas subtotal | 17.15 | 18.14 | 18.36 | 18.73 | 18.29 | 18.87 | 20.06 | 18.50 | 20.13 | 21.86 |
| Metallurgical coal | 0.56 | 0.61 | 0.60 | 0.59 | 0.52 | 0.52 | 0.52 | 0.46 | 0.46 | 0.47 |
| Other coal | 1.10 | 1.06 | 1.06 | 1.05 | 1.06 | 1.06 | 1.06 | 1.10 | 1.11 | 1.11 |
| Coal-to-liquids heat and power | 0.00 | 0.00 | 0.00 | 0.11 | 0.00 | 0.09 | 0.21 | 0.00 | 0.15 | 0.39 |
| Net coal coke imports | 0.01 | -0.01 | -0.01 | -0.01 | -0.04 | -0.04 | -0.04 | -0.05 | -0.05 | -0.05 |
| Coal subtotal | 1.67 | 1.66 | 1.64 | 1.74 | 1.54 | 1.63 | 1.74 | 1.51 | 1.67 | 1.91 |
| Biofuels heat and coproducts | 0.67 | 0.82 | 0.82 | 0.80 | 0.86 | 0.85 | 0.87 | 1.27 | 1.37 | 1.64 |
| Renewable energy[13] | 2.08 | 2.23 | 2.28 | 2.33 | 2.51 | 2.54 | 2.56 | 2.86 | 2.86 | 2.86 |
| Liquid hydrogen | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| Electricity | 12.71 | 13.63 | 13.54 | 13.44 | 14.71 | 14.59 | 14.46 | 15.91 | 15.72 | 15.55 |
| **Delivered energy** | **71.01** | **74.92** | **74.01** | **73.08** | **75.57** | **74.38** | **73.56** | **79.21** | **77.63** | **77.41** |
| Electricity related losses | 26.69 | 27.24 | 27.03 | 26.80 | 28.60 | 28.43 | 28.30 | 30.11 | 30.00 | 30.32 |
| **Total** | **97.70** | **102.16** | **101.04** | **99.88** | **104.17** | **102.81** | **101.86** | **109.32** | **107.64** | **107.73** |
| **Electric power[14]** | | | | | | | | | | |
| Distillate fuel oil | 0.06 | 0.08 | 0.08 | 0.08 | 0.08 | 0.08 | 0.08 | 0.08 | 0.08 | 0.08 |
| Residual fuel oil | 0.23 | 0.10 | 0.10 | 0.10 | 0.10 | 0.10 | 0.10 | 0.11 | 0.11 | 0.11 |
| Liquid fuels and other petroleum subtotal | 0.30 | 0.18 | 0.18 | 0.17 | 0.18 | 0.18 | 0.18 | 0.19 | 0.19 | 0.19 |
| Natural gas | 7.76 | 8.42 | 8.40 | 8.31 | 9.52 | 9.08 | 8.60 | 10.47 | 9.70 | 8.16 |
| Steam coal | 17.99 | 17.28 | 16.95 | 16.76 | 18.01 | 18.07 | 18.19 | 18.81 | 18.68 | 18.79 |
| Nuclear / uranium[15] | 8.26 | 9.25 | 9.25 | 9.25 | 9.49 | 9.49 | 9.53 | 9.14 | 9.44 | 10.63 |
| Renewable energy[16] | 4.74 | 5.44 | 5.49 | 5.45 | 5.85 | 5.93 | 5.99 | 7.13 | 7.44 | 7.80 |
| Electricity imports | 0.13 | 0.08 | 0.08 | 0.08 | 0.04 | 0.05 | 0.05 | 0.06 | 0.06 | 0.08 |
| **Total[17]** | **39.40** | **40.87** | **40.57** | **40.24** | **43.31** | **43.02** | **42.76** | **46.02** | **45.73** | **45.87** |

## Table C2. Energy consumption by sector and source (continued)
(quadrillion Btu per year, unless otherwise noted)

| Sector and source | 2011 | Projections | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | | 2020 | | | 2030 | | | 2040 | | |
| | | 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 | 2.82 | 3.11 | 3.21 | 3.26 | 3.08 | 3.23 | 3.25 | 2.99 | 3.08 | 3.08 |
| Propylene | 0.40 | 0.58 | 0.56 | 0.52 | 0.56 | 0.52 | 0.49 | 0.50 | 0.46 | 0.46 |
| E85[8] | 0.05 | 0.06 | 0.08 | 0.11 | 0.13 | 0.16 | 0.34 | 0.15 | 0.17 | 0.61 |
| Motor gasoline[2] | 16.64 | 15.88 | 15.26 | 14.53 | 14.30 | 13.43 | 12.57 | 14.26 | 13.03 | 11.87 |
| Jet fuel[9] | 3.01 | 3.12 | 3.11 | 3.10 | 3.29 | 3.28 | 3.28 | 3.43 | 3.42 | 3.41 |
| Kerosene | 0.03 | 0.03 | 0.03 | 0.02 | 0.03 | 0.02 | 0.02 | 0.03 | 0.02 | 0.02 |
| Distillate fuel oil | 8.18 | 9.65 | 9.43 | 9.01 | 10.15 | 9.59 | 8.45 | 11.34 | 9.82 | 8.49 |
| Residual fuel oil | 1.24 | 1.18 | 1.15 | 1.12 | 1.20 | 1.15 | 1.13 | 1.23 | 1.17 | 1.15 |
| Petrochemical feedstocks | 0.88 | 1.09 | 1.03 | 1.02 | 1.15 | 1.08 | 1.08 | 1.15 | 1.09 | 1.09 |
| Other petroleum[12] | 3.77 | 3.93 | 3.69 | 3.52 | 3.94 | 3.61 | 3.44 | 4.26 | 3.80 | 3.58 |
| Liquid fuels and other petroleum subtotal | 37.02 | 38.62 | 37.54 | 36.21 | 37.84 | 36.08 | 34.04 | 39.34 | 36.07 | 33.77 |
| Natural gas | 22.79 | 24.32 | 24.36 | 24.55 | 25.53 | 25.27 | 25.62 | 26.59 | 26.75 | 26.18 |
| Natural-gas-to-liquids heat and power | 0.00 | 0.00 | 0.13 | 0.15 | 0.00 | 0.21 | 0.28 | 0.00 | 0.33 | 0.53 |
| Lease and plant fuel[6] | 1.42 | 1.53 | 1.57 | 1.62 | 1.56 | 1.73 | 2.00 | 1.64 | 1.97 | 2.49 |
| Pipeline natural gas | 0.70 | 0.71 | 0.71 | 0.72 | 0.72 | 0.74 | 0.76 | 0.74 | 0.78 | 0.81 |
| Natural gas subtotal | 24.91 | 26.56 | 26.77 | 27.04 | 27.80 | 27.95 | 28.66 | 28.97 | 29.83 | 30.01 |
| Metallurgical coal | 0.56 | 0.61 | 0.60 | 0.59 | 0.52 | 0.52 | 0.52 | 0.46 | 0.46 | 0.47 |
| Other coal | 19.09 | 18.34 | 18.01 | 17.81 | 19.06 | 19.12 | 19.25 | 19.91 | 19.79 | 19.90 |
| Coal-to-liquids heat and power | 0.00 | 0.00 | 0.00 | 0.11 | 0.00 | 0.09 | 0.21 | 0.00 | 0.15 | 0.39 |
| Net coal coke imports | 0.01 | -0.01 | -0.01 | -0.01 | -0.04 | -0.04 | -0.04 | -0.05 | -0.05 | -0.05 |
| Coal subtotal | 19.66 | 18.93 | 18.59 | 18.50 | 19.54 | 19.70 | 19.94 | 20.32 | 20.35 | 20.71 |
| Nuclear / uranium[15] | 8.26 | 9.25 | 9.25 | 9.25 | 9.49 | 9.49 | 9.53 | 9.14 | 9.44 | 10.63 |
| Biofuels heat and coproducts | 0.67 | 0.82 | 0.82 | 0.80 | 0.86 | 0.85 | 0.87 | 1.27 | 1.37 | 1.64 |
| Renewable energy[18] | 6.82 | 7.67 | 7.77 | 7.77 | 8.36 | 8.47 | 8.54 | 9.98 | 10.30 | 10.65 |
| Liquid hydrogen | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| Electricity imports | 0.13 | 0.08 | 0.08 | 0.08 | 0.04 | 0.05 | 0.05 | 0.06 | 0.06 | 0.08 |
| **Total** | **97.70** | **102.16** | **101.04** | **99.88** | **104.17** | **102.81** | **101.86** | **109.32** | **107.64** | **107.73** |
| **Energy use and related statistics** | | | | | | | | | | |
| Delivered energy use | 71.01 | 74.92 | 74.01 | 73.08 | 75.57 | 74.38 | 73.56 | 79.21 | 77.63 | 77.41 |
| Total energy use | 97.70 | 102.16 | 101.04 | 99.88 | 104.17 | 102.81 | 101.86 | 109.32 | 107.64 | 107.73 |
| Ethanol consumed in motor gasoline and E85 | 1.17 | 1.34 | 1.34 | 1.30 | 1.29 | 1.24 | 1.28 | 1.29 | 1.21 | 1.40 |
| Population (millions) | 312.38 | 340.45 | 340.45 | 340.45 | 372.41 | 372.41 | 372.41 | 404.39 | 404.39 | 404.39 |
| Gross domestic product (billion 2005 dollars) | 13,299 | 16,932 | 16,859 | 16,803 | 21,437 | 21,355 | 21,301 | 27,460 | 27,277 | 27,270 |
| Carbon dioxide emissions (million metric tons) | 5,471 | 5,559 | 5,455 | 5,365 | 5,636 | 5,523 | 5,432 | 5,887 | 5,691 | 5,548 |

[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 water heating, and electricity generation from wind and solar photovoltaic sources.
[2]Includes ethanol (blends of 15 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 water heating and electricity generation from wind and solar photovoltaic sources.
[4]Includes energy for combined heat and power plants that have a non-regulatory status, and small on-site generating systems.
[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, in natural gas processing plant machinery, and for liquefaction in export facilities.
[7]Includes consumption of energy produced from hydroelectric, wood and wood waste, municipal waste, and other biomass sources. Excludes ethanol blends (15 percent or less) in motor gasoline.
[8]E85 refers to a blend of 85 percent ethanol (renewable) and 15 percent motor gasoline (nonrenewable). To address cold starting issues, the percentage of ethanol varies seasonally. The annual average ethanol content of 74 percent is used for this forecast.
[9]Includes only kerosene type.
[10]Diesel fuel for on- and off- road use.
[11]Includes aviation gasoline and lubricants.
[12]Includes unfinished oils, natural gasoline, motor gasoline blending components, aviation gasoline, lubricants, still gas, asphalt, road oil, petroleum coke, and miscellaneous petroleum products.
[13]Includes electricity generated for sale to the grid and for own use from renewable sources, and non-electric energy from renewable sources. Excludes ethanol and nonmarketed renewable energy consumption for geothermal heat pumps, buildings photovoltaic systems, and solar thermal water heaters.
[14]Includes consumption of energy by electricity-only and combined heat and power plants that have a regulatory status.
[15]These values represent the energy obtained from uranium when it is used in light water reactors. The total energy content of uranium is much larger, but alternative processes are required to take advantage of it.
[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 water heaters.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Data for 2011 are model results and may differ slightly from official EIA data reports.
**Sources:** 2011 consumption based on: U.S. Energy Information Administration (EIA), *Annual Energy Review 2011*, DOE-EIA-0384(2011) (Washington, DC, September 2012). 2011 population and gross domestic product: IHS Global Insight Industry and Employment models, August 2012. 2011 carbon dioxide emissions: EIA, *Monthly Energy Review*, DOE/EIA-0035(2012/08) (Washington, DC, August 2012). **Projections:** EIA, AEO2013 National Energy Modeling System runs LOWPRICE.D031213A, REF2013.D102312A, and HIGHPRICE.D110912A.

## Table C3. Energy prices by sector and source
(2011 dollars per million Btu, unless otherwise noted)

| Sector and source | 2011 | Projections | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | | 2020 | | | 2030 | | | 2040 | | |
| | | Low oil price | Reference | High oil price | Low oil price | Reference | High oil price | Low oil price | Reference | High oil Price |
| **Residential** | | | | | | | | | | |
| Propane | 25.06 | 21.80 | 23.41 | 24.99 | 22.85 | 25.73 | 27.96 | 23.78 | 27.99 | 30.62 |
| Distillate fuel oil | 26.38 | 20.03 | 26.91 | 35.67 | 20.57 | 31.26 | 42.37 | 21.07 | 36.54 | 50.06 |
| Natural gas | 10.80 | 11.59 | 11.78 | 12.00 | 13.08 | 13.37 | 13.99 | 15.59 | 16.36 | 17.67 |
| Electricity | 34.34 | 33.29 | 33.62 | 34.11 | 33.95 | 34.56 | 35.51 | 35.71 | 37.10 | 38.85 |
| **Commercial** | | | | | | | | | | |
| Propane | 22.10 | 18.08 | 20.04 | 22.02 | 19.35 | 22.97 | 25.89 | 20.51 | 25.94 | 29.52 |
| Distillate fuel oil | 25.87 | 17.40 | 24.26 | 32.84 | 18.14 | 28.51 | 39.66 | 18.60 | 33.74 | 47.32 |
| Residual fuel oil | 19.17 | 9.76 | 14.82 | 21.95 | 10.44 | 18.77 | 27.34 | 10.95 | 23.41 | 35.80 |
| Natural gas | 8.84 | 9.30 | 9.47 | 9.68 | 10.43 | 10.70 | 11.29 | 12.49 | 13.21 | 14.48 |
| Electricity | 29.98 | 28.27 | 28.57 | 29.04 | 28.02 | 28.65 | 29.55 | 30.33 | 31.75 | 33.58 |
| **Industrial[1]** | | | | | | | | | | |
| Propane | 22.54 | 18.40 | 20.51 | 22.64 | 19.74 | 23.64 | 26.78 | 20.90 | 26.78 | 30.64 |
| Distillate fuel oil | 26.50 | 17.82 | 24.67 | 33.13 | 18.79 | 28.91 | 40.09 | 19.26 | 34.16 | 47.78 |
| Residual fuel oil | 18.86 | 12.07 | 17.19 | 24.34 | 12.71 | 21.09 | 29.79 | 13.21 | 25.78 | 38.15 |
| Natural gas[2] | 4.89 | 5.44 | 5.53 | 5.70 | 6.43 | 6.56 | 7.12 | 8.30 | 8.88 | 10.01 |
| Metallurgical coal | 7.01 | 8.62 | 8.75 | 8.89 | 9.91 | 10.09 | 10.28 | 10.86 | 11.11 | 11.40 |
| Other industrial coal | 3.43 | 3.33 | 3.44 | 3.57 | 3.54 | 3.71 | 3.85 | 3.86 | 4.06 | 4.26 |
| Coal to liquids | - - | - - | - - | 2.24 | - - | 2.55 | 2.64 | - - | 2.95 | 3.16 |
| Electricity | 19.98 | 18.50 | 18.72 | 19.10 | 19.29 | 19.73 | 20.42 | 21.63 | 22.74 | 24.17 |
| **Transportation** | | | | | | | | | | |
| Propane | 26.06 | 22.87 | 24.48 | 26.05 | 23.92 | 26.80 | 29.02 | 24.86 | 29.07 | 31.69 |
| E85[3] | 25.30 | 25.56 | 29.64 | 35.68 | 20.70 | 26.94 | 37.43 | 20.19 | 30.58 | 44.43 |
| Motor gasoline[4] | 28.70 | 21.86 | 27.84 | 35.94 | 21.67 | 30.73 | 41.08 | 22.12 | 36.18 | 49.07 |
| Jet fuel[5] | 22.49 | 14.55 | 21.50 | 29.81 | 15.36 | 26.03 | 36.77 | 16.16 | 31.07 | 44.44 |
| Diesel fuel (distillate fuel oil)[6] | 26.15 | 19.78 | 26.61 | 35.02 | 20.82 | 30.81 | 42.01 | 21.30 | 36.05 | 49.68 |
| Residual fuel oil | 17.83 | 10.00 | 14.91 | 21.28 | 10.59 | 18.34 | 26.44 | 10.98 | 22.45 | 32.70 |
| Natural gas[7] | 16.14 | 16.52 | 16.87 | 18.82 | 17.02 | 18.90 | 19.95 | 18.48 | 21.20 | 22.38 |
| Electricity | 32.77 | 29.58 | 29.60 | 29.71 | 31.05 | 31.53 | 32.69 | 33.65 | 35.07 | 37.01 |
| **Electric power[8]** | | | | | | | | | | |
| Distillate fuel oil | 23.30 | 15.56 | 22.45 | 31.20 | 16.06 | 26.80 | 37.87 | 16.58 | 32.03 | 45.58 |
| Residual fuel oil | 15.97 | 19.75 | 24.94 | 32.23 | 20.84 | 29.36 | 38.13 | 21.51 | 34.54 | 46.84 |
| Natural gas | 4.77 | 4.79 | 4.90 | 5.07 | 5.86 | 6.05 | 6.55 | 7.79 | 8.38 | 9.34 |
| Steam coal | 2.38 | 2.41 | 2.52 | 2.64 | 2.69 | 2.87 | 3.02 | 2.97 | 3.20 | 3.40 |
| **Average price to all users[9]** | | | | | | | | | | |
| Propane | 17.13 | 11.34 | 13.69 | 16.52 | 12.98 | 18.14 | 23.54 | 14.84 | 23.79 | 31.84 |
| E85[3] | 25.30 | 25.56 | 29.64 | 35.68 | 20.70 | 26.94 | 37.43 | 20.19 | 30.58 | 44.43 |
| Motor gasoline[4] | 28.47 | 21.86 | 27.84 | 35.94 | 21.66 | 30.72 | 41.07 | 22.11 | 36.17 | 49.06 |
| Jet fuel[5] | 22.49 | 14.55 | 21.50 | 29.81 | 15.36 | 26.03 | 36.77 | 16.16 | 31.07 | 44.44 |
| Distillate fuel oil | 26.18 | 19.41 | 26.25 | 34.69 | 20.42 | 30.48 | 41.65 | 20.92 | 35.73 | 49.32 |
| Residual fuel oil | 17.65 | 11.00 | 15.97 | 22.54 | 11.66 | 19.59 | 27.83 | 12.16 | 23.95 | 34.70 |
| Natural gas | 6.68 | 6.96 | 7.07 | 7.39 | 7.97 | 8.27 | 9.28 | 9.89 | 10.94 | 12.65 |
| Metallurgical coal | 7.01 | 8.62 | 8.75 | 8.89 | 9.91 | 10.09 | 10.28 | 10.86 | 11.11 | 11.40 |
| Other coal | 2.45 | 2.47 | 2.57 | 2.70 | 2.74 | 2.92 | 3.07 | 3.02 | 3.25 | 3.45 |
| Coal to liquids | - - | - - | - - | 2.24 | - - | 2.55 | 2.64 | - - | 2.95 | 3.16 |
| Electricity | 29.03 | 27.20 | 27.50 | 27.97 | 27.84 | 28.41 | 29.28 | 30.27 | 31.58 | 33.25 |
| **Non-renewable energy expenditures by sector (billion 2011 dollars)** | | | | | | | | | | |
| Residential | 248.08 | 238.38 | 243.44 | 249.62 | 263.61 | 271.05 | 280.75 | 306.29 | 319.63 | 335.09 |
| Commercial | 179.97 | 177.66 | 181.68 | 186.64 | 197.00 | 203.80 | 212.25 | 236.19 | 249.60 | 264.69 |
| Industrial | 225.18 | 228.72 | 259.03 | 297.45 | 246.43 | 294.99 | 347.49 | 273.46 | 353.70 | 429.01 |
| Transportation | 718.25 | 544.15 | 694.73 | 877.09 | 533.56 | 749.40 | 956.36 | 574.15 | 900.68 | 1,141.45 |
| Total non-renewable expenditures | 1,371.48 | 1,188.91 | 1,378.87 | 1,610.80 | 1,240.60 | 1,519.24 | 1,796.86 | 1,390.08 | 1,823.61 | 2,170.24 |
| Transportation renewable expenditures | 1.24 | 1.50 | 2.44 | 3.87 | 2.75 | 4.39 | 12.79 | 2.94 | 5.05 | 27.17 |
| **Total expenditures** | **1,372.71** | **1,190.40** | **1,381.31** | **1,614.68** | **1,243.35** | **1,523.63** | **1,809.64** | **1,393.03** | **1,828.66** | **2,197.42** |

## Table C3. Energy prices by sector and source (continued)
(nominal dollars per million Btu, unless otherwise noted)

| Sector and source | 2011 | 2020 Low oil price | 2020 Reference | 2020 High oil price | 2030 Low oil price | 2030 Reference | 2030 High oil price | 2040 Low oil price | 2040 Reference | 2040 High oil price |
|---|---|---|---|---|---|---|---|---|---|---|
| **Residential** | | | | | | | | | | |
| Propane | 25.06 | 25.19 | 27.00 | 28.64 | 31.98 | 35.51 | 37.99 | 40.37 | 46.20 | 49.38 |
| Distillate fuel oil | 26.38 | 23.14 | 31.03 | 40.88 | 28.79 | 43.14 | 57.58 | 35.77 | 60.31 | 80.74 |
| Natural gas | 10.80 | 13.39 | 13.58 | 13.75 | 18.30 | 18.45 | 19.01 | 26.46 | 27.01 | 28.51 |
| Electricity | 34.34 | 38.46 | 38.76 | 39.09 | 47.52 | 47.69 | 48.25 | 60.62 | 61.23 | 62.66 |
| **Commercial** | | | | | | | | | | |
| Propane | 22.10 | 20.89 | 23.11 | 25.24 | 27.08 | 31.70 | 35.18 | 34.81 | 42.82 | 47.62 |
| Distillate fuel oil | 25.87 | 20.10 | 27.97 | 37.64 | 25.39 | 39.34 | 53.88 | 31.58 | 55.68 | 76.33 |
| Residual fuel oil | 19.17 | 11.28 | 17.09 | 25.16 | 14.61 | 25.90 | 37.15 | 18.59 | 38.64 | 57.74 |
| Natural gas | 8.84 | 10.74 | 10.92 | 11.09 | 14.59 | 14.76 | 15.34 | 21.19 | 21.81 | 23.36 |
| Electricity | 29.98 | 32.66 | 32.94 | 33.29 | 39.21 | 39.54 | 40.15 | 51.48 | 52.40 | 54.16 |
| **Industrial**[1] | | | | | | | | | | |
| Propane | 22.54 | 21.26 | 23.65 | 25.95 | 27.62 | 32.62 | 36.39 | 35.48 | 44.20 | 49.42 |
| Distillate fuel oil | 26.50 | 20.59 | 28.45 | 37.97 | 26.30 | 39.89 | 54.47 | 32.69 | 56.39 | 77.06 |
| Residual fuel oil | 18.86 | 13.95 | 19.82 | 27.90 | 17.78 | 29.10 | 40.48 | 22.42 | 42.55 | 61.53 |
| Natural gas[2] | 4.89 | 6.29 | 6.38 | 6.53 | 9.00 | 9.05 | 9.68 | 14.10 | 14.66 | 16.15 |
| Metallurgical coal | 7.01 | 9.96 | 10.09 | 10.19 | 13.87 | 13.92 | 13.97 | 18.43 | 18.34 | 18.39 |
| Other industrial coal | 3.43 | 3.85 | 3.97 | 4.09 | 4.96 | 5.12 | 5.23 | 6.56 | 6.70 | 6.87 |
| Coal to liquids | - - | - - | - - | 2.57 | - - | 3.52 | 3.59 | - - | 4.87 | 5.10 |
| Electricity | 19.98 | 21.38 | 21.59 | 21.89 | 26.99 | 27.22 | 27.75 | 36.72 | 37.54 | 38.98 |
| **Transportation** | | | | | | | | | | |
| Propane | 26.06 | 26.42 | 28.22 | 29.86 | 33.48 | 36.98 | 39.43 | 42.20 | 47.97 | 51.11 |
| E85[3] | 25.30 | 29.53 | 34.18 | 40.89 | 28.97 | 37.18 | 50.86 | 34.27 | 50.46 | 71.65 |
| Motor gasoline[4] | 28.70 | 25.26 | 32.10 | 41.20 | 30.32 | 42.41 | 55.82 | 37.54 | 59.72 | 79.15 |
| Jet fuel[5] | 22.49 | 16.81 | 24.79 | 34.16 | 21.49 | 35.92 | 49.96 | 27.44 | 51.27 | 71.68 |
| Diesel fuel (distillate fuel oil)[6] | 26.15 | 22.85 | 30.68 | 40.14 | 29.14 | 42.52 | 57.08 | 36.15 | 59.50 | 80.13 |
| Residual fuel oil | 17.83 | 11.56 | 17.19 | 24.38 | 14.82 | 25.31 | 35.93 | 18.63 | 37.06 | 52.75 |
| Natural gas[7] | 16.14 | 19.08 | 19.46 | 21.57 | 23.81 | 26.08 | 27.11 | 31.37 | 34.98 | 36.09 |
| Electricity | 32.77 | 34.17 | 34.13 | 34.06 | 43.46 | 43.51 | 44.42 | 57.12 | 57.88 | 59.70 |
| **Electric power**[8] | | | | | | | | | | |
| Distillate fuel oil | 23.30 | 17.98 | 25.89 | 35.76 | 22.48 | 36.98 | 51.45 | 28.15 | 52.87 | 73.52 |
| Residual fuel oil | 15.97 | 22.82 | 28.76 | 36.94 | 29.17 | 40.52 | 51.81 | 36.52 | 57.01 | 75.54 |
| Natural gas | 4.77 | 5.53 | 5.65 | 5.81 | 8.20 | 8.35 | 8.90 | 13.22 | 13.83 | 15.06 |
| Steam coal | 2.38 | 2.79 | 2.90 | 3.03 | 3.76 | 3.96 | 4.10 | 5.04 | 5.28 | 5.48 |

## Table C3. Energy prices by sector and source (continued)
(nominal dollars per million Btu, unless otherwise noted)

| Sector and source | 2011 | Projections | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | | 2020 | | | 2030 | | | 2040 | | |
| | | 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[9]** | | | | | | | | | | |
| Propane | 17.13 | 13.10 | 15.78 | 18.93 | 18.16 | 25.03 | 31.99 | 25.19 | 39.26 | 51.36 |
| E85[3] | 25.30 | 29.53 | 34.18 | 40.89 | 28.97 | 37.18 | 50.86 | 34.27 | 50.46 | 71.65 |
| Motor gasoline[4] | 28.47 | 25.25 | 32.10 | 41.19 | 30.32 | 42.40 | 55.81 | 37.53 | 59.70 | 79.13 |
| Jet fuel[5] | 22.49 | 16.81 | 24.79 | 34.16 | 21.49 | 35.92 | 49.96 | 27.44 | 51.27 | 71.68 |
| Distillate fuel oil | 26.18 | 22.42 | 30.27 | 39.76 | 28.58 | 42.07 | 56.59 | 35.52 | 58.97 | 79.55 |
| Residual fuel oil | 17.65 | 12.71 | 18.41 | 25.83 | 16.32 | 27.03 | 37.81 | 20.63 | 39.53 | 55.97 |
| Natural gas | 6.68 | 8.04 | 8.16 | 8.47 | 11.15 | 11.41 | 12.61 | 16.79 | 18.06 | 20.40 |
| Metallurgical coal | 7.01 | 9.96 | 10.09 | 10.19 | 13.87 | 13.92 | 13.97 | 18.43 | 18.34 | 18.39 |
| Other coal | 2.45 | 2.86 | 2.97 | 3.10 | 3.83 | 4.03 | 4.17 | 5.13 | 5.37 | 5.57 |
| Coal to liquids | - - | - - | - - | 2.57 | - - | 3.52 | 3.59 | - - | 4.87 | 5.10 |
| Electricity | 29.03 | 31.42 | 31.71 | 32.05 | 38.95 | 39.20 | 39.78 | 51.37 | 52.12 | 53.63 |
| **Non-renewable energy expenditures by sector (billion nominal dollars)** | | | | | | | | | | |
| Residential | 248.08 | 275.42 | 280.71 | 286.10 | 368.92 | 374.04 | 381.49 | 519.90 | 527.54 | 540.45 |
| Commercial | 179.97 | 205.26 | 209.48 | 213.91 | 275.70 | 281.23 | 288.41 | 400.92 | 411.95 | 426.92 |
| Industrial | 225.18 | 264.27 | 298.68 | 340.93 | 344.87 | 407.07 | 472.18 | 464.18 | 583.76 | 691.95 |
| Transportation | 718.25 | 628.70 | 801.07 | 1,005.28 | 746.71 | 1,034.13 | 1,299.52 | 974.58 | 1,486.52 | 1,841.03 |
| Total non-renewable expenditures | 1,371.48 | 1,373.65 | 1,589.94 | 1,846.23 | 1,736.20 | 2,096.47 | 2,441.59 | 2,359.59 | 3,009.77 | 3,500.35 |
| Transportation renewable expenditures | 1.24 | 1.73 | 2.81 | 4.44 | 3.85 | 6.06 | 17.38 | 5.00 | 8.33 | 43.83 |
| **Total expenditures** | **1,372.71** | **1,375.38** | **1,592.75** | **1,850.67** | **1,740.04** | **2,102.52** | **2,458.97** | **2,364.59** | **3,018.11** | **3,544.17** |

[1]Includes energy for combined heat and power plants that have a non-regulatory status, and small on-site generating systems.
[2]Excludes use for lease and plant fuel.
[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]Kerosene-type jet fuel. Includes Federal and State taxes while excluding county and local taxes.
[6]Diesel fuel for on-road use. Includes Federal and State taxes while excluding county and local taxes.
[7]Natural gas used as a vehicle fuel. Includes estimated motor vehicle fuel taxes and estimated dispensing costs or charges.
[8]Includes electricity-only and combined heat and power plants that have a regulatory status.
[9]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 2011 are model results and may differ slightly from official EIA data reports.
**Sources:** 2011 prices for motor gasoline, distillate fuel oil, and jet fuel are based on prices in the U.S. Energy Information Administration (EIA), *Petroleum Marketing Monthly*, DOE/EIA-0380(2012/08) (Washington, DC, August 2012). 2011 residential, commercial, and industrial natural gas delivered prices: EIA, *Natural Gas Monthly*, DOE/EIA-0130Natural Gas Monthly, DOE/EIA-0130(2012/07) (Washington, DC, July 2012). 2011 transportation sector natural gas delivered prices are model results. 2011 electric power sector distillate and residual fuel oil prices: EIA, *Monthly Energy Review*, DOE/EIA-0035(2012/09) (Washington, DC, September 2012). 2011 electric power sector natural gas prices: EIA, *Electric Power Monthly*, DOE/EIA-0226, April 2011 and April 2012, Table 4.2, and EIA, *State Energy Data Report 2010*, DOE/EIA-0214(2010) (Washington, DC, June 2012). 2011 coal prices based on: EIA, *Quarterly Coal Report, October-December 2011*, DOE/EIA-0121(2011/4Q) (Washington, DC, March 2012) and EIA, AEO2013 National Energy Modeling System run REF2013.D102312A. 2011 electricity prices: EIA, *Annual Energy Review 2011*, DOE/EIA-0384(2011) (Washington, DC, September 2012). 2011 E85 prices derived from monthly prices in the Clean Cities Alternative Fuel Price Report. **Projections:** EIA, AEO2013 National Energy Modeling System runs LOWPRICE.D031213A, REF2013.D102312A, and HIGHPRICE.D110912A.

# Table C4. Liquid fuels supply and disposition
(million barrels per day, unless otherwise noted)

| Supply and disposition | 2011 | Projections | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | | 2020 | | | 2030 | | | 2040 | | |
| | | 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] | 5.67 | 7.12 | 7.47 | 7.78 | 5.57 | 6.30 | 7.04 | 4.67 | 6.13 | 6.82 |
| Alaska | 0.57 | 0.49 | 0.49 | 0.52 | 0.25 | 0.38 | 0.54 | 0.00 | 0.41 | 0.40 |
| Lower 48 states | 5.10 | 6.64 | 6.98 | 7.26 | 5.32 | 5.92 | 6.50 | 4.67 | 5.72 | 6.42 |
| Net imports | 8.89 | 7.48 | 6.82 | 6.05 | 8.70 | 7.36 | 5.98 | 10.13 | 7.57 | 5.86 |
| Gross imports | 8.94 | 7.48 | 6.82 | 6.05 | 8.70 | 7.36 | 5.98 | 10.13 | 7.57 | 5.86 |
| Exports | 0.05 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| Other crude supply[2] | 0.26 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| **Total crude supply** | **14.81** | **14.61** | **14.29** | **13.82** | **14.27** | **13.66** | **13.02** | **14.79** | **13.70** | **12.68** |
| **Other petroleum supply** | **3.02** | **4.28** | **4.04** | **3.84** | **4.18** | **3.82** | **3.37** | **4.08** | **3.29** | **2.80** |
| Natural gas plant liquids | 2.22 | 3.01 | 3.13 | 3.20 | 2.86 | 2.90 | 3.01 | 2.77 | 2.92 | 3.06 |
| Net product imports | -0.30 | 0.18 | -0.13 | -0.35 | 0.26 | -0.08 | -0.57 | 0.20 | -0.67 | -1.15 |
| Gross refined product imports[3] | 1.15 | 1.62 | 1.47 | 1.41 | 1.73 | 1.53 | 1.24 | 1.99 | 1.42 | 1.07 |
| Unfinished oil imports | 0.69 | 0.64 | 0.56 | 0.47 | 0.63 | 0.51 | 0.40 | 0.60 | 0.45 | 0.30 |
| Blending component imports | 0.72 | 0.71 | 0.63 | 0.56 | 0.63 | 0.54 | 0.44 | 0.59 | 0.40 | 0.36 |
| Exports | 2.86 | 2.78 | 2.79 | 2.79 | 2.73 | 2.67 | 2.64 | 2.98 | 2.94 | 2.89 |
| Refinery processing gain[4] | 1.08 | 1.09 | 1.04 | 0.99 | 1.06 | 1.00 | 0.93 | 1.12 | 1.03 | 0.89 |
| Product stock withdrawal | 0.03 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| **Other non-petroleum supply** | **1.09** | **1.42** | **1.51** | **1.54** | **1.42** | **1.58** | **1.70** | **1.65** | **1.97** | **2.42** |
| Supply from renewable sources | 0.90 | 1.18 | 1.18 | 1.15 | 1.17 | 1.14 | 1.18 | 1.38 | 1.43 | 1.70 |
| Ethanol | 0.84 | 1.08 | 1.08 | 1.04 | 1.04 | 0.99 | 1.03 | 1.04 | 0.97 | 1.12 |
| Domestic production | 0.91 | 1.01 | 1.01 | 0.97 | 0.98 | 0.95 | 0.94 | 0.98 | 0.89 | 1.00 |
| Net imports | -0.07 | 0.07 | 0.07 | 0.07 | 0.05 | 0.04 | 0.09 | 0.06 | 0.08 | 0.12 |
| Biodiesel | 0.06 | 0.07 | 0.08 | 0.08 | 0.02 | 0.08 | 0.08 | 0.02 | 0.08 | 0.09 |
| Domestic production | 0.06 | 0.06 | 0.07 | 0.07 | 0.00 | 0.07 | 0.07 | 0.00 | 0.07 | 0.07 |
| Net imports | 0.00 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 |
| Other biomass-derived liquids[5] | 0.00 | 0.03 | 0.02 | 0.02 | 0.11 | 0.06 | 0.07 | 0.33 | 0.38 | 0.49 |
| Liquids from gas | 0.00 | 0.00 | 0.08 | 0.09 | 0.00 | 0.13 | 0.17 | 0.00 | 0.20 | 0.31 |
| Liquids from coal | 0.00 | 0.00 | 0.00 | 0.05 | 0.00 | 0.04 | 0.09 | 0.00 | 0.06 | 0.16 |
| Other[6] | 0.18 | 0.24 | 0.25 | 0.26 | 0.25 | 0.28 | 0.26 | 0.26 | 0.28 | 0.24 |
| **Total primary supply[7]** | **18.92** | **20.31** | **19.84** | **19.21** | **19.87** | **19.06** | **18.10** | **20.52** | **18.96** | **17.90** |
| **Liquid fuels consumption** | | | | | | | | | | |
| **by fuel** | | | | | | | | | | |
| Liquefied petroleum gases | 2.30 | 2.84 | 2.90 | 2.91 | 2.81 | 2.90 | 2.90 | 2.69 | 2.75 | 2.76 |
| E85[8] | 0.03 | 0.04 | 0.06 | 0.07 | 0.09 | 0.11 | 0.23 | 0.10 | 0.11 | 0.42 |
| Motor gasoline[9] | 8.74 | 8.67 | 8.34 | 7.94 | 7.81 | 7.34 | 6.87 | 7.79 | 7.12 | 6.49 |
| Jet fuel[10] | 1.43 | 1.52 | 1.52 | 1.51 | 1.60 | 1.60 | 1.59 | 1.67 | 1.66 | 1.66 |
| Distillate fuel oil[11] | 3.90 | 4.59 | 4.48 | 4.29 | 4.83 | 4.56 | 4.02 | 5.40 | 4.67 | 4.04 |
| Diesel | 3.51 | 4.12 | 4.04 | 3.87 | 4.41 | 4.18 | 3.66 | 5.00 | 4.33 | 3.71 |
| Residual fuel oil | 0.46 | 0.51 | 0.50 | 0.49 | 0.52 | 0.50 | 0.49 | 0.54 | 0.51 | 0.50 |
| Other[12] | 2.08 | 2.18 | 2.04 | 1.96 | 2.21 | 2.03 | 1.95 | 2.34 | 2.11 | 2.02 |
| **by sector** | | | | | | | | | | |
| Residential and commercial | 1.06 | 1.06 | 1.01 | 0.96 | 1.02 | 0.95 | 0.90 | 1.01 | 0.91 | 0.86 |
| Industrial[13] | 4.43 | 5.21 | 5.10 | 5.02 | 5.22 | 5.05 | 4.95 | 5.25 | 5.00 | 4.87 |
| Transportation | 13.63 | 14.00 | 13.65 | 13.11 | 13.57 | 12.95 | 12.13 | 14.18 | 12.95 | 12.07 |
| Electric power[14] | 0.13 | 0.08 | 0.08 | 0.08 | 0.08 | 0.08 | 0.08 | 0.08 | 0.08 | 0.08 |
| **Total** | **18.95** | **20.35** | **19.84** | **19.17** | **19.89** | **19.04** | **18.06** | **20.53** | **18.95** | **17.89** |
| **Discrepancy[15]** | **-0.03** | **-0.04** | **0.01** | **0.03** | **-0.02** | **0.02** | **0.03** | **-0.01** | **0.01** | **0.01** |

## Table C4. Liquid fuels supply and disposition (continued)
(million barrels per day, unless otherwise noted)

| Supply and disposition | 2011 | Projections | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | | 2020 | | | 2030 | | | 2040 | | |
| | | 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] | 17.7 | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 | 17.5 |
| Capacity utilization rate (percent)[17] | 86.0 | 92.7 | 90.7 | 87.7 | 90.6 | 86.7 | 82.7 | 93.9 | 86.9 | 80.5 |
| Net import share of product supplied (percent) | 45.0 | 38.2 | 34.1 | 30.1 | 45.4 | 38.5 | 30.5 | 50.6 | 36.9 | 27.1 |
| Net expenditures for imported crude oil and petroleum products (billion 2011 dollars) | 362.66 | 184.56 | 259.66 | 336.24 | 220.72 | 342.67 | 410.95 | 265.20 | 433.65 | 495.87 |

[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 on-site production of diesel and gasoline.
[6]Includes domestic sources of other blending components, other hydrocarbons, and ethers.
[7]Total crude supply plus other petroleum supply plus other non-petroleum supply.
[8]E85 refers to a blend of 85 percent ethanol (renewable) and 15 percent motor gasoline (nonrenewable). To address cold starting issues, the percentage of ethanol varies seasonally. The annual average ethanol content of 74 percent is used for this forecast.
[9]Includes ethanol and ethers blended into gasoline.
[10]Includes only kerosene type.
[11]Includes distillate 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 energy for combined heat and power plants that have a non-regulatory status, and small on-site generating systems.
[14]Includes consumption of energy by electricity-only and combined heat and power plants that have a regulatory status.
[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 2011 are model results and may differ slightly from official EIA data reports.
**Sources:** 2011 product supplied based on: U.S. Energy Information Administration (EIA), *Annual Energy Review 2011*, DOE/EIA-0384(2011) (Washington, DC, September 2012). Other 2011 data: EIA, *Petroleum Supply Annual 2011*, DOE/EIA-0340(2011)/1 (Washington, DC, August 2012). **Projections:** EIA, AEO2013 National Energy Modeling System runs LOWPRICE.D031213A, REF2013.D102312A, and HIGHPRICE.D110912A.

## Table C5. Petroleum product prices
(2011 dollars per gallon, unless otherwise noted)

| Sector and fuel | 2011 | Projections | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | | 2020 | | | 2030 | | | 2040 | | |
| | | Low oil price | Reference | High oil price | Low oil price | Reference | High oil price | Low oil price | Reference | High oil price |
| **Crude oil prices (2011 dollars per barrel)** | | | | | | | | | | |
| Brent spot | 111.26 | 68.90 | 105.57 | 155.28 | 71.90 | 130.47 | 191.90 | 74.90 | 162.68 | 237.16 |
| West Texas Intermediate spot | 94.86 | 66.90 | 103.57 | 153.28 | 69.90 | 128.47 | 189.90 | 72.90 | 160.68 | 235.16 |
| Average imported refiners acquisition cost[1] | 102.65 | 66.28 | 102.19 | 149.31 | 68.39 | 125.64 | 184.97 | 70.93 | 154.96 | 228.39 |
| **Delivered sector product prices** | | | | | | | | | | |
| **Residential** | | | | | | | | | | |
| Propane | 2.13 | 1.85 | 1.98 | 2.11 | 1.93 | 2.17 | 2.35 | 2.01 | 2.35 | 2.56 |
| Distillate fuel oil | 3.66 | 2.78 | 3.73 | 4.95 | 2.85 | 4.34 | 5.88 | 2.92 | 5.07 | 6.94 |
| **Commercial** | | | | | | | | | | |
| Distillate fuel oil | 3.57 | 2.40 | 3.34 | 4.53 | 2.50 | 3.93 | 5.47 | 2.56 | 4.65 | 6.52 |
| Residual fuel oil | 2.87 | 1.46 | 2.22 | 3.29 | 1.56 | 2.81 | 4.09 | 1.64 | 3.50 | 5.36 |
| Residual fuel oil (2011 dollars per barrel) | 120.49 | 61.38 | 93.20 | 138.00 | 65.63 | 117.99 | 171.88 | 68.87 | 147.19 | 225.06 |
| **Industrial[2]** | | | | | | | | | | |
| Propane | 1.92 | 1.56 | 1.74 | 1.92 | 1.67 | 1.99 | 2.25 | 1.76 | 2.25 | 2.56 |
| Distillate fuel oil | 3.64 | 2.45 | 3.39 | 4.55 | 2.58 | 3.97 | 5.50 | 2.64 | 4.69 | 6.56 |
| Residual fuel oil | 2.82 | 1.81 | 2.57 | 3.64 | 1.90 | 3.16 | 4.46 | 1.98 | 3.86 | 5.71 |
| Residual fuel oil (2011 dollars per barrel) | 118.58 | 75.90 | 108.07 | 153.04 | 79.88 | 132.58 | 187.31 | 83.04 | 162.10 | 239.83 |
| **Transportation** | | | | | | | | | | |
| Propane | 2.22 | 1.94 | 2.07 | 2.20 | 2.02 | 2.26 | 2.44 | 2.10 | 2.44 | 2.65 |
| Ethanol (E85)[3] | 2.42 | 2.44 | 2.83 | 3.41 | 1.98 | 2.57 | 3.57 | 1.93 | 2.92 | 4.24 |
| Ethanol wholesale price | 2.54 | 2.79 | 3.00 | 3.11 | 2.39 | 2.28 | 2.78 | 2.33 | 2.48 | 3.25 |
| Motor gasoline[4] | 3.45 | 2.61 | 3.32 | 4.29 | 2.59 | 3.67 | 4.90 | 2.64 | 4.32 | 5.86 |
| Jet fuel[5] | 3.04 | 1.96 | 2.90 | 4.02 | 2.07 | 3.51 | 4.96 | 2.18 | 4.19 | 6.00 |
| Diesel fuel (distillate fuel oil)[6] | 3.58 | 2.71 | 3.65 | 4.80 | 2.85 | 4.22 | 5.76 | 2.92 | 4.94 | 6.81 |
| Residual fuel oil | 2.67 | 1.50 | 2.23 | 3.18 | 1.58 | 2.75 | 3.96 | 1.64 | 3.36 | 4.90 |
| Residual fuel oil (2011 dollars per barrel) | 112.11 | 62.89 | 93.74 | 133.76 | 66.56 | 115.30 | 166.23 | 69.01 | 141.16 | 205.61 |
| **Electric power[7]** | | | | | | | | | | |
| Distillate fuel oil | 3.23 | 2.16 | 3.11 | 4.33 | 2.23 | 3.72 | 5.25 | 2.30 | 4.44 | 6.32 |
| Residual fuel oil | 2.39 | 2.96 | 3.73 | 4.82 | 3.12 | 4.39 | 5.71 | 3.22 | 5.17 | 7.01 |
| Residual fuel oil (2011 dollars per barrel) | 100.43 | 124.18 | 156.82 | 202.60 | 131.04 | 184.59 | 239.73 | 135.26 | 217.18 | 294.46 |
| **Refined petroleum product prices[8]** | | | | | | | | | | |
| Propane | 1.46 | 0.96 | 1.16 | 1.40 | 1.10 | 1.53 | 1.98 | 1.25 | 2.00 | 2.66 |
| Motor gasoline[4] | 3.42 | 2.61 | 3.32 | 4.29 | 2.59 | 3.67 | 4.90 | 2.64 | 4.32 | 5.86 |
| Jet fuel[5] | 3.04 | 1.96 | 2.90 | 4.02 | 2.07 | 3.51 | 4.96 | 2.18 | 4.19 | 6.00 |
| Distillate fuel oil | 3.59 | 2.66 | 3.60 | 4.76 | 2.80 | 4.18 | 5.71 | 2.87 | 4.90 | 6.77 |
| Residual fuel oil | 2.64 | 1.65 | 2.39 | 3.37 | 1.75 | 2.93 | 4.17 | 1.82 | 3.59 | 5.19 |
| Residual fuel oil (2011 dollars per barrel) | 110.98 | 69.15 | 100.39 | 141.70 | 73.32 | 123.16 | 174.94 | 76.42 | 150.58 | 218.18 |
| **Average** | **3.11** | **2.30** | **3.01** | **3.91** | **2.35** | **3.43** | **4.61** | **2.44** | **4.10** | **5.58** |

## Table C5. Petroleum product prices (continued)
(nominal dollars per gallon, unless otherwise noted)

| Sector and fuel | 2011 | Projections | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | | 2020 | | | 2030 | | | 2040 | | |
| | | 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)** | | | | | | | | | | |
| Brent spot | 111.26 | 79.61 | 121.73 | 177.97 | 100.62 | 180.04 | 260.76 | 127.14 | 268.50 | 382.50 |
| West Texas Intermediate spot | 94.86 | 77.30 | 119.43 | 175.68 | 97.82 | 177.28 | 258.04 | 123.74 | 265.20 | 379.28 |
| Average imported refiners acquisition cost[1] | 102.65 | 76.57 | 117.84 | 171.13 | 95.72 | 173.38 | 251.33 | 120.40 | 255.76 | 368.36 |
| **Delivered sector product prices** | | | | | | | | | | |
| **Residential** | | | | | | | | | | |
| Propane | 2.13 | 2.14 | 2.29 | 2.42 | 2.70 | 2.99 | 3.19 | 3.41 | 3.88 | 4.13 |
| Distillate fuel oil | 3.66 | 3.21 | 4.30 | 5.67 | 3.99 | 5.98 | 7.99 | 4.96 | 8.37 | 11.20 |
| **Commercial** | | | | | | | | | | |
| Distillate fuel oil | 3.57 | 2.77 | 3.86 | 5.19 | 3.50 | 5.42 | 7.43 | 4.35 | 7.68 | 10.52 |
| Residual fuel oil | 2.87 | 1.69 | 2.56 | 3.77 | 2.19 | 3.88 | 5.56 | 2.78 | 5.78 | 8.64 |
| **Industrial[2]** | | | | | | | | | | |
| Propane | 1.92 | 1.80 | 2.00 | 2.20 | 2.33 | 2.75 | 3.06 | 2.99 | 3.71 | 4.14 |
| Distillate fuel oil | 3.64 | 2.83 | 3.91 | 5.21 | 3.61 | 5.48 | 7.48 | 4.49 | 7.74 | 10.58 |
| Residual fuel oil | 2.82 | 2.09 | 2.97 | 4.18 | 2.66 | 4.36 | 6.06 | 3.36 | 6.37 | 9.21 |
| **Transportation** | | | | | | | | | | |
| Propane | 2.22 | 2.24 | 2.39 | 2.53 | 2.83 | 3.12 | 3.31 | 3.56 | 4.03 | 4.28 |
| Ethanol (E85)[3] | 2.42 | 2.82 | 3.26 | 3.90 | 2.77 | 3.55 | 4.85 | 3.27 | 4.82 | 6.84 |
| Ethanol wholesale price | 2.54 | 3.22 | 3.46 | 3.57 | 3.35 | 3.14 | 3.77 | 3.96 | 4.09 | 5.24 |
| Motor gasoline[4] | 3.45 | 3.02 | 3.83 | 4.92 | 3.62 | 5.06 | 6.66 | 4.48 | 7.13 | 9.45 |
| Jet fuel[5] | 3.04 | 2.27 | 3.35 | 4.61 | 2.90 | 4.85 | 6.74 | 3.70 | 6.92 | 9.68 |
| Diesel fuel (distillate fuel oil)[6] | 3.58 | 3.13 | 4.20 | 5.50 | 3.99 | 5.83 | 7.82 | 4.95 | 8.15 | 10.98 |
| Residual fuel oil | 2.67 | 1.73 | 2.57 | 3.65 | 2.22 | 3.79 | 5.38 | 2.79 | 5.55 | 7.90 |
| **Electric power[7]** | | | | | | | | | | |
| Distillate fuel oil | 3.23 | 2.49 | 3.59 | 4.96 | 3.12 | 5.13 | 7.14 | 3.90 | 7.33 | 10.20 |
| Residual fuel oil | 2.39 | 3.42 | 4.31 | 5.53 | 4.37 | 6.06 | 7.76 | 5.47 | 8.53 | 11.31 |
| **Refined petroleum product prices[8]** | | | | | | | | | | |
| Propane | 1.46 | 1.11 | 1.34 | 1.60 | 1.53 | 2.11 | 2.69 | 2.13 | 3.30 | 4.30 |
| Motor gasoline[4] | 3.42 | 3.02 | 3.83 | 4.92 | 3.62 | 5.06 | 6.66 | 4.48 | 7.13 | 9.45 |
| Jet fuel[5] | 3.04 | 2.27 | 3.35 | 4.61 | 2.90 | 4.85 | 6.74 | 3.70 | 6.92 | 9.68 |
| Distillate fuel oil | 3.59 | 3.08 | 4.15 | 5.46 | 3.92 | 5.77 | 7.76 | 4.87 | 8.09 | 10.91 |
| Residual fuel oil (nominal dollars per barrel) | 110.98 | 79.90 | 115.76 | 162.41 | 102.62 | 169.95 | 237.72 | 129.72 | 248.53 | 351.90 |
| **Average** | **3.11** | **2.66** | **3.47** | **4.49** | **3.28** | **4.74** | **6.26** | **4.14** | **6.76** | **9.00** |

[1]Weighted average price delivered to U.S. refiners.
[2]Includes combined heat and power plants that have a non-regulatory status, and small on-site generating systems.
[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 that have a regulatory status.
[8]Weighted averages of end-use fuel prices are derived from the prices in each sector and the corresponding sectoral consumption.
Note: Data for 2011 are model results and may differ slightly from official EIA data reports.
**Sources:** 2011 prices for motor gasoline, distillate fuel oil, and jet fuel are based on: Energy Information Administration (EIA), *Petroleum Marketing Monthly*, DOE/EIA-0380(2012/08) (Washington, DC, August 2012). 2011 crude oil spot prices: Thomson Reuters. 2011 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." 2011 electric power prices based on: *Monthly Energy Review*, DOE/EIA-0035(2012/09) (Washington, DC, September 2012). 2011 E85 prices derived from monthly prices in the Clean Cities Alternative Fuel Price Report. 2011 wholesale ethanol prices derived from Bloomberg U.S. average rack price. **Projections:** EIA, AEO2013 National Energy Modeling System runs LOWPRICE.D031213A, REF2013.D102312A, and HIGHPRICE.D110912A.

# Table C6. International liquids supply and disposition summary
(million barrels per day, unless otherwise noted)

| Supply and disposition | 2011 | Projections | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | | 2020 | | | 2030 | | | 2040 | | |
| | | Low oil price | Reference | High oil price | Low oil price | Reference | High oil price | Low oil price | Reference | High oil price |
| **Crude oil spot prices** | | | | | | | | | | |
| **(2011 dollars per barrel)** | | | | | | | | | | |
| Brent | 111.26 | 68.90 | 105.57 | 155.28 | 71.90 | 130.47 | 191.90 | 74.90 | 162.68 | 237.16 |
| West Texas Intermediate | 94.86 | 66.90 | 103.57 | 153.28 | 69.90 | 128.47 | 189.90 | 72.90 | 160.68 | 235.16 |
| **(nominal dollars per barrel)** | | | | | | | | | | |
| Brent | 111.26 | 79.61 | 121.73 | 177.97 | 100.62 | 180.04 | 260.76 | 127.14 | 268.50 | 382.50 |
| West Texas Intermediate | 94.86 | 77.30 | 119.43 | 175.68 | 97.82 | 177.28 | 258.04 | 123.74 | 265.20 | 379.28 |
| **Liquids consumption[1]** | | | | | | | | | | |
| OECD | | | | | | | | | | |
| United States (50 states) | 18.68 | 20.00 | 19.49 | 18.84 | 19.55 | 18.72 | 17.73 | 20.20 | 18.64 | 17.53 |
| United States territories | 0.28 | 0.37 | 0.32 | 0.29 | 0.43 | 0.36 | 0.32 | 0.47 | 0.37 | 0.33 |
| Canada | 2.29 | 2.35 | 2.21 | 2.11 | 2.37 | 2.18 | 2.14 | 2.48 | 2.30 | 2.39 |
| Mexico and Chile | 2.41 | 2.81 | 2.66 | 2.57 | 3.30 | 3.05 | 3.01 | 3.82 | 3.47 | 3.51 |
| OECD Europe[2] | 14.28 | 14.59 | 13.81 | 13.19 | 15.21 | 13.96 | 13.31 | 15.99 | 14.21 | 13.54 |
| Japan | 4.46 | 4.75 | 4.41 | 4.15 | 4.73 | 4.25 | 3.96 | 4.54 | 3.94 | 3.64 |
| South Korea | 2.32 | 2.75 | 2.56 | 2.41 | 3.01 | 2.66 | 2.53 | 3.26 | 2.74 | 2.66 |
| Australia and New Zealand | 1.12 | 1.23 | 1.19 | 1.13 | 1.30 | 1.22 | 1.16 | 1.46 | 1.30 | 1.23 |
| **Total OECD** | **45.83** | **48.85** | **46.63** | **44.69** | **49.90** | **46.40** | **44.15** | **52.21** | **46.96** | **44.82** |
| Non-OECD | | | | | | | | | | |
| Russia | 3.13 | 3.77 | 3.53 | 3.37 | 4.12 | 3.83 | 3.67 | 4.25 | 3.95 | 3.86 |
| Other Europe and Eurasia[3] | 2.27 | 2.54 | 2.38 | 2.31 | 2.90 | 2.63 | 2.56 | 3.45 | 3.07 | 3.02 |
| China | 9.85 | 13.00 | 13.29 | 13.23 | 13.79 | 15.58 | 17.21 | 13.83 | 17.59 | 22.13 |
| India | 3.28 | 4.30 | 4.27 | 4.24 | 5.27 | 5.61 | 6.33 | 5.75 | 6.81 | 9.40 |
| Other Asia[4] | 6.87 | 8.00 | 7.88 | 7.65 | 9.09 | 9.30 | 9.35 | 10.20 | 11.25 | 11.72 |
| Middle East | 7.51 | 8.56 | 8.40 | 8.16 | 8.81 | 8.92 | 9.03 | 9.07 | 9.78 | 10.57 |
| Africa | 3.31 | 3.78 | 3.63 | 3.47 | 4.10 | 4.05 | 3.96 | 4.29 | 4.49 | 4.43 |
| Brazil | 2.59 | 3.15 | 3.01 | 2.83 | 3.34 | 3.37 | 3.34 | 3.54 | 4.00 | 4.27 |
| Other Central and South America | 3.37 | 3.73 | 3.42 | 3.44 | 4.09 | 3.71 | 3.73 | 4.45 | 4.02 | 4.09 |
| **Total non-OECD** | **42.18** | **50.82** | **49.82** | **48.69** | **55.51** | **57.00** | **59.16** | **58.84** | **64.97** | **73.49** |
| **Total liquids consumption** | **88.01** | **99.67** | **96.45** | **93.38** | **105.41** | **103.41** | **103.31** | **111.05** | **111.93** | **118.31** |
| **Liquids production** | | | | | | | | | | |
| OPEC[5] | | | | | | | | | | |
| Middle East | 25.40 | 30.13 | 26.65 | 24.08 | 33.47 | 29.88 | 28.47 | 39.68 | 35.09 | 34.24 |
| North Africa | 2.39 | 3.65 | 3.27 | 3.00 | 3.75 | 3.48 | 3.33 | 4.22 | 3.96 | 3.87 |
| West Africa | 4.31 | 5.73 | 5.33 | 4.80 | 6.28 | 5.61 | 5.33 | 6.78 | 5.89 | 5.70 |
| South America | 2.99 | 3.41 | 3.09 | 3.03 | 3.44 | 3.01 | 3.05 | 3.80 | 3.20 | 3.27 |
| **Total OPEC** | **35.08** | **42.92** | **38.34** | **34.90** | **46.94** | **41.98** | **40.17** | **54.49** | **48.13** | **47.08** |
| Non-OPEC | | | | | | | | | | |
| OECD | | | | | | | | | | |
| United States (50 states) | 10.11 | 12.23 | 12.74 | 13.11 | 10.53 | 11.42 | 12.28 | 9.81 | 11.67 | 12.74 |
| Canada | 3.66 | 5.20 | 5.09 | 6.01 | 6.15 | 5.91 | 7.25 | 5.73 | 6.14 | 7.78 |
| Mexico and Chile | 2.99 | 1.93 | 1.96 | 1.92 | 1.69 | 1.98 | 1.96 | 1.58 | 2.12 | 2.15 |
| OECD Europe[2] | 4.19 | 3.38 | 3.38 | 3.28 | 2.90 | 2.84 | 2.76 | 3.51 | 3.36 | 3.56 |
| Japan | 0.18 | 0.18 | 0.17 | 0.17 | 0.19 | 0.18 | 0.19 | 0.20 | 0.19 | 0.20 |
| Australia and New Zealand | 0.58 | 0.54 | 0.54 | 0.53 | 0.56 | 0.56 | 0.55 | 0.79 | 0.87 | 0.90 |
| **Total OECD** | **21.71** | **23.46** | **23.88** | **25.02** | **22.03** | **22.90** | **24.99** | **21.62** | **24.35** | **27.33** |
| Non-OECD | | | | | | | | | | |
| Russia | 10.23 | 10.29 | 10.75 | 10.80 | 10.76 | 11.43 | 11.45 | 10.53 | 11.48 | 11.88 |
| Other Europe and Eurasia[3] | 3.26 | 4.15 | 4.20 | 4.00 | 4.17 | 4.85 | 4.58 | 3.33 | 5.24 | 5.27 |
| China | 4.34 | 4.56 | 4.59 | 4.58 | 5.43 | 5.50 | 5.82 | 5.24 | 5.42 | 8.36 |
| Other Asia[4] | 3.74 | 3.52 | 3.55 | 3.46 | 3.09 | 3.09 | 3.02 | 2.89 | 2.87 | 2.96 |
| Middle East | 1.43 | 1.21 | 1.23 | 1.19 | 1.08 | 1.09 | 1.05 | 0.89 | 0.89 | 0.89 |
| Africa | 2.68 | 3.02 | 3.08 | 3.00 | 3.03 | 3.10 | 3.01 | 3.11 | 3.18 | 3.24 |
| Brazil | 2.53 | 4.52 | 4.35 | 4.51 | 6.72 | 6.96 | 7.14 | 6.53 | 7.61 | 8.82 |
| Other Central and South America | 2.17 | 2.38 | 2.40 | 2.32 | 2.42 | 2.46 | 2.38 | 2.65 | 2.69 | 2.82 |
| **Total non-OECD** | **30.39** | **33.65** | **34.15** | **33.87** | **36.69** | **38.47** | **38.46** | **35.17** | **39.37** | **44.24** |
| **Total liquids production** | **87.18** | **100.03** | **96.38** | **93.79** | **105.65** | **103.35** | **103.62** | **111.29** | **111.85** | **118.65** |
| OPEC liquids market share (percent) | 40.2 | 42.9 | 39.8 | 37.2 | 44.4 | 40.6 | 38.8 | 49.0 | 43.0 | 39.7 |

**Table C6. International liquids supply and disposition summary (continued)**
(million barrels per day, unless otherwise noted)

| Supply and disposition | 2011 | 2020 Low oil price | 2020 Reference | 2020 High oil price | 2030 Low oil price | 2030 Reference | 2030 High oil price | 2040 Low oil price | 2040 Reference | 2040 High oil price |
|---|---|---|---|---|---|---|---|---|---|---|
| **Selected world liquids production subtotals:** | | | | | | | | | | |
| Petroleum[6] | | | | | | | | | | |
| Crude oil and equivalents[7] | 74.08 | 84.06 | 80.28 | 77.15 | 87.05 | 85.26 | 84.30 | 90.27 | 90.90 | 94.50 |
| Tight oil | 1.27 | 3.53 | 3.83 | 3.99 | 4.39 | 4.91 | 5.34 | 4.73 | 6.10 | 7.97 |
| Bitumen[8] | 1.74 | 3.18 | 3.00 | 3.87 | 4.29 | 3.95 | 5.19 | 3.99 | 4.26 | 5.71 |
| Natural gas plant liquids | 8.66 | 10.46 | 10.88 | 10.96 | 11.24 | 11.75 | 11.88 | 12.07 | 12.88 | 13.04 |
| Refinery processing gain[9] | 2.28 | 2.35 | 2.20 | 2.14 | 2.64 | 2.50 | 2.43 | 2.94 | 2.82 | 2.72 |
| Liquids from renewable sources[10] | 1.33 | 2.31 | 2.08 | 2.38 | 3.51 | 2.49 | 3.14 | 4.69 | 2.93 | 4.99 |
| Liquids from coal[11] | 0.18 | 0.36 | 0.40 | 0.58 | 0.76 | 0.95 | 1.24 | 0.86 | 1.19 | 2.62 |
| Liquids from natural gas[12] | 0.12 | 0.30 | 0.39 | 0.37 | 0.32 | 0.48 | 0.49 | 0.31 | 0.55 | 0.65 |
| Liquids from kerogen[13] | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 |
| **Petroleum production[6]** | | | | | | | | | | |
| OPEC[5] | | | | | | | | | | |
| Middle East | 25.34 | 29.93 | 26.44 | 23.89 | 33.24 | 29.64 | 28.25 | 39.45 | 34.84 | 34.01 |
| North Africa | 2.39 | 3.65 | 3.27 | 3.00 | 3.75 | 3.48 | 3.33 | 4.22 | 3.96 | 3.87 |
| West Africa | 4.31 | 5.70 | 5.30 | 4.77 | 6.25 | 5.58 | 5.30 | 6.75 | 5.86 | 5.67 |
| South America | 2.99 | 3.41 | 3.09 | 3.03 | 3.44 | 3.01 | 3.05 | 3.80 | 3.20 | 3.27 |
| **Total OPEC** | **35.03** | **42.69** | **38.10** | **34.70** | **46.68** | **41.71** | **39.93** | **54.24** | **47.86** | **46.83** |
| Non-OPEC | | | | | | | | | | |
| OECD | | | | | | | | | | |
| United States (50 states) | 9.25 | 11.22 | 11.64 | 11.96 | 9.49 | 10.21 | 10.98 | 8.55 | 10.08 | 10.78 |
| Canada | 3.64 | 5.17 | 5.07 | 5.98 | 6.09 | 5.87 | 7.20 | 5.65 | 6.10 | 7.70 |
| Mexico and Chile | 2.99 | 1.93 | 1.96 | 1.92 | 1.69 | 1.98 | 1.96 | 1.58 | 2.12 | 2.15 |
| OECD Europe[2] | 3.98 | 3.16 | 3.16 | 3.05 | 2.60 | 2.60 | 2.50 | 3.09 | 3.09 | 3.13 |
| Japan | 0.17 | 0.17 | 0.16 | 0.16 | 0.18 | 0.18 | 0.18 | 0.18 | 0.18 | 0.18 |
| Australia and New Zealand | 0.57 | 0.53 | 0.53 | 0.52 | 0.54 | 0.55 | 0.54 | 0.77 | 0.86 | 0.89 |
| **Total OECD** | **20.60** | **22.18** | **22.52** | **23.60** | **20.60** | **21.39** | **23.36** | **19.83** | **22.43** | **24.82** |
| Non-OECD | | | | | | | | | | |
| Russia | 10.23 | 10.29 | 10.75 | 10.80 | 10.76 | 11.42 | 11.45 | 10.53 | 11.47 | 11.88 |
| Other Europe and Eurasia[3] | 3.25 | 4.14 | 4.19 | 3.99 | 4.16 | 4.84 | 4.58 | 3.32 | 5.23 | 5.26 |
| China | 4.30 | 4.41 | 4.44 | 4.30 | 4.73 | 4.83 | 4.86 | 4.33 | 4.52 | 5.96 |
| Other Asia[4] | 3.67 | 3.40 | 3.42 | 3.32 | 2.87 | 2.88 | 2.79 | 2.65 | 2.65 | 2.67 |
| Middle East | 1.43 | 1.21 | 1.23 | 1.19 | 1.08 | 1.09 | 1.05 | 0.89 | 0.89 | 0.89 |
| Africa | 2.47 | 2.72 | 2.75 | 2.66 | 2.72 | 2.74 | 2.64 | 2.80 | 2.82 | 2.83 |
| Brazil | 2.25 | 3.52 | 3.57 | 3.44 | 5.03 | 5.92 | 5.68 | 4.20 | 6.48 | 6.44 |
| Other Central and South America | 2.09 | 2.30 | 2.33 | 2.24 | 2.31 | 2.38 | 2.29 | 2.50 | 2.60 | 2.66 |
| **Total non-OECD** | **29.69** | **32.00** | **32.69** | **31.95** | **33.65** | **36.11** | **35.32** | **31.21** | **36.66** | **38.60** |
| **Total petroleum production** | **85.31** | **96.87** | **93.32** | **90.24** | **100.93** | **99.20** | **98.61** | **105.28** | **106.96** | **110.25** |
| OPEC petroleum market share (percent) | 41.1 | 44.1 | 40.8 | 38.4 | 46.2 | 42.0 | 40.5 | 51.5 | 44.7 | 42.5 |

[1]Includes both OPEC and non-OPEC consumers in the regional breakdown.
[2]OECD Europe = Organization for Economic Cooperation and Development - Austria, Belgium, Czech Republic, Denmark, Estonia, Finland, France, Germany, Greece, Hungary, Iceland, Ireland, Italy, Luxembourg, the Netherlands, Norway, Poland, Portugal, Slovakia, Slovenia, Spain, Sweden, Switzerland, Turkey, and the United Kingdom.
[3]Other Europe and Eurasia = Albania, Armenia, Azerbaijan, Belarus, Bosnia and Herzegovina, Bulgaria, Croatia, Georgia, Kazakhstan, Kyrgyzstan, Latvia, Lithuania, Macedonia, Malta, Moldova, Montenegro, Romania, Serbia, Tajikistan, Turkmenistan, Ukraine, and Uzbekistan.
[4]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.
[5]OPEC = Organization of Petroleum Exporting Countries - Algeria, Angola, Ecuador, Iran, Iraq, Kuwait, Libya, Nigeria, Qatar, Saudi Arabia, the United Arab Emirates, and Venezuela.
[6]Includes production of crude oil (including lease condensate, tight oil (shale oil), extra-heavy oil, and bitumen (oil sands)), natural gas plant liquids, refinery gains, and other hydrogen and hydrocarbons for refinery feedstocks.
[7]Includes crude oil, lease condensate, tight oil (shale oil), extra-heavy oil, and bitumen (oil sands).
[8]Includes diluted and upgraded/synthetic bitumen (syncrude).
[9]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.
[10]Includes liquids produced from energy crops.
[11]Includes liquids converted from coal via the Fischer-Tropsch coal-to-liquids process.
[12]Includes liquids converted from natural gas via the Fischer-Tropsch natural-gas-to-liquids process.
[13]Includes liquids produced from kerogen (oil shale, not to be confused with tight oil (shale oil).
Note: Ethanol is represented in motor gasoline equivalent barrels. Totals may not equal sum of components due to independent rounding. Data for 2011 are model results and may differ slightly from official EIA data reports.
**Sources:** 2011 crude oil spot prices: Thomson Reuters. **2011 quantities and projections:** Energy Information Administration (EIA), AEO2013 National Energy Modeling System runs LOWPRICE.D031213A, REF2013.D102312A, and HIGHPRICE.D110912A and EIA, Generate World Oil Balance Model.

# Results from side cases

## Table D1. Key results for demand sector technology cases

| Consumption, emissions, combined heat and power capacity and generation | 2011 | 2020 | | | | 2030 | | | |
|---|---|---|---|---|---|---|---|---|---|
| | | 2012 Demand Technology | Reference | High Demand Technology | Best Available Demand Technology | 2012 Demand Technology | Reference | High Demand Technology | Best Available Demand Technology |
| **Energy consumption (quadrillion Btu)** | | | | | | | | | |
| **Residential** | | | | | | | | | |
| Liquid fuels and other petroleum[1] | 1.14 | 1.07 | 1.05 | 1.02 | 0.99 | 0.98 | 0.93 | 0.88 | 0.84 |
| Natural gas | 4.83 | 4.73 | 4.62 | 4.36 | 4.03 | 4.70 | 4.46 | 4.00 | 3.48 |
| Coal | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.00 |
| Renewable energy[2] | 0.45 | 0.46 | 0.44 | 0.42 | 0.40 | 0.50 | 0.45 | 0.41 | 0.37 |
| Electricity | 4.86 | 4.92 | 4.84 | 4.44 | 3.95 | 5.54 | 5.36 | 4.75 | 4.02 |
| **Total residential** | **11.28** | **11.18** | **10.95** | **10.25** | **9.38** | **11.72** | **11.20** | **10.04** | **8.72** |
| Nonmarketed renewables, residential | 0.04 | 0.18 | 0.20 | 0.20 | 0.23 | 0.19 | 0.22 | 0.27 | 0.38 |
| **Commercial** | | | | | | | | | |
| Liquid fuels and other petroleum[3] | 0.69 | 0.65 | 0.65 | 0.66 | 0.66 | 0.64 | 0.64 | 0.64 | 0.64 |
| Natural gas | 3.23 | 3.37 | 3.40 | 3.37 | 3.39 | 3.46 | 3.50 | 3.46 | 3.50 |
| Coal | 0.05 | 0.05 | 0.05 | 0.05 | 0.05 | 0.05 | 0.05 | 0.05 | 0.05 |
| Renewable energy[4] | 0.13 | 0.13 | 0.13 | 0.13 | 0.13 | 0.13 | 0.13 | 0.13 | 0.13 |
| Electricity | 4.50 | 4.86 | 4.72 | 4.36 | 4.11 | 5.52 | 5.22 | 4.44 | 4.11 |
| **Total commercial** | **8.60** | **9.06** | **8.95** | **8.56** | **8.34** | **9.80** | **9.54** | **8.71** | **8.42** |
| Nonmarketed renewables, commercial | 0.11 | 0.20 | 0.20 | 0.23 | 0.23 | 0.22 | 0.24 | 0.32 | 0.33 |
| **Industrial[5]** | | | | | | | | | |
| Liquefied petroleum gases | 2.10 | 2.46 | 2.46 | 2.47 | 2.51 | 2.48 | 2.47 | 2.49 | 2.57 |
| Propylene | 0.40 | 0.54 | 0.56 | 0.58 | 0.59 | 0.50 | 0.52 | 0.54 | 0.55 |
| Distillate fuel oil | 1.21 | 1.38 | 1.22 | 1.16 | 1.21 | 1.49 | 1.18 | 1.07 | 1.16 |
| Petrochemical feedstocks | 0.88 | 1.04 | 1.03 | 1.02 | 1.01 | 1.11 | 1.08 | 1.06 | 1.06 |
| Other petroleum[6] | 4.00 | 4.14 | 3.97 | 3.84 | 3.92 | 4.20 | 3.89 | 3.69 | 3.87 |
| Liquid fuels and other petroleum | 8.57 | 9.57 | 9.25 | 9.06 | 9.23 | 9.78 | 9.14 | 8.85 | 9.21 |
| Natural gas | 8.34 | 9.89 | 9.56 | 9.61 | 9.60 | 10.74 | 9.91 | 9.93 | 9.95 |
| Coal | 1.62 | 1.65 | 1.58 | 1.56 | 1.59 | 1.64 | 1.57 | 1.55 | 1.60 |
| Renewable energy[7] | 2.18 | 2.50 | 2.53 | 2.56 | 2.54 | 2.74 | 2.82 | 2.94 | 2.84 |
| Electricity | 3.33 | 4.09 | 3.95 | 3.86 | 3.97 | 4.33 | 3.96 | 3.82 | 4.07 |
| **Total industrial** | **24.04** | **27.71** | **26.87** | **26.66** | **26.93** | **29.23** | **27.40** | **27.08** | **27.66** |
| **Transportation** | | | | | | | | | |
| E85[8] | 0.05 | 0.08 | 0.08 | 0.08 | 0.09 | 0.16 | 0.16 | 0.16 | 0.16 |
| Motor gasoline[9] | 16.31 | 14.87 | 14.88 | 14.79 | 14.85 | 13.04 | 13.06 | 13.04 | 13.08 |
| Jet fuel | 3.01 | 3.11 | 3.11 | 3.10 | 3.11 | 3.28 | 3.28 | 3.24 | 3.28 |
| Distillate fuel oil | 5.91 | 7.29 | 7.28 | 7.04 | 7.22 | 7.65 | 7.61 | 7.23 | 7.50 |
| Other petroleum[10] | 1.05 | 1.06 | 1.06 | 1.06 | 1.06 | 1.08 | 1.08 | 1.07 | 1.08 |
| Liquid fuels and other petroleum | 26.32 | 26.41 | 26.42 | 26.07 | 26.34 | 25.22 | 25.20 | 24.74 | 25.11 |
| Pipeline fuel natural gas | 0.70 | 0.73 | 0.71 | 0.69 | 0.69 | 0.78 | 0.74 | 0.70 | 0.69 |
| Compressed / liquefied natural gas | 0.04 | 0.07 | 0.08 | 0.07 | 0.08 | 0.22 | 0.26 | 0.21 | 0.35 |
| Liquid hydrogen | 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 | 0.05 | 0.05 |
| **Total transportation** | **27.09** | **27.25** | **27.24** | **26.87** | **27.13** | **26.27** | **26.25** | **25.70** | **26.19** |
| **Electric power[11]** | | | | | | | | | |
| Distillate and residual fuel oil | 0.30 | 0.18 | 0.18 | 0.16 | 0.15 | 0.19 | 0.18 | 0.16 | 0.15 |
| Natural gas | 7.76 | 8.60 | 8.40 | 7.97 | 7.97 | 9.91 | 9.08 | 7.58 | 7.41 |
| Steam coal | 17.99 | 17.74 | 16.95 | 15.13 | 13.28 | 18.89 | 18.07 | 16.01 | 13.99 |
| Nuclear / uranium[12] | 8.26 | 9.25 | 9.25 | 9.16 | 9.11 | 9.54 | 9.49 | 9.41 | 9.36 |
| Renewable energy[13] | 4.74 | 5.58 | 5.49 | 5.27 | 5.12 | 6.46 | 5.93 | 5.57 | 5.31 |
| Net electricity imports | 0.13 | 0.09 | 0.08 | 0.08 | 0.08 | 0.05 | 0.05 | 0.03 | 0.03 |
| **Total electric power[14]** | **39.40** | **41.67** | **40.57** | **37.99** | **35.93** | **45.27** | **43.02** | **38.99** | **36.47** |
| **Total energy consumption** | | | | | | | | | |
| Liquid fuels and other petroleum | 37.02 | 37.88 | 37.54 | 36.97 | 37.37 | 36.80 | 36.08 | 35.28 | 35.94 |
| Natural gas | 24.91 | 27.39 | 26.77 | 26.07 | 25.74 | 29.82 | 27.95 | 25.87 | 25.37 |
| Steam coal | 19.66 | 19.46 | 18.59 | 16.75 | 14.92 | 20.58 | 19.70 | 17.61 | 15.65 |
| Nuclear / uranium[12] | 8.26 | 9.25 | 9.25 | 9.16 | 9.11 | 9.54 | 9.49 | 9.41 | 9.36 |
| Renewable energy[15] | 7.49 | 8.67 | 8.58 | 8.38 | 8.18 | 9.82 | 9.31 | 9.05 | 8.64 |
| Other[16] | 0.35 | 0.31 | 0.31 | 0.31 | 0.31 | 0.28 | 0.28 | 0.26 | 0.26 |
| **Total energy consumption** | **97.70** | **102.96** | **101.04** | **97.63** | **95.64** | **106.85** | **102.81** | **97.46** | **95.22** |

| 2040 | | | | Annual Growth 2011-2040 (percent) | | | |
|---|---|---|---|---|---|---|---|
| 2012 Demand Technology | Reference | High Demand Technology | Best Available Demand Technology | 2012 Demand Technology | Reference | High Demand Technology | Best Available Demand Technology |
| | | | | | | | |
| 0.93 | 0.86 | 0.80 | 0.75 | -0.7% | -1.0% | -1.2% | -1.4% |
| 4.61 | 4.23 | 3.70 | 3.12 | -0.2% | -0.5% | -0.9% | -1.5% |
| 0.01 | 0.00 | 0.00 | 0.00 | -0.3% | -0.9% | -1.3% | -1.6% |
| 0.53 | 0.45 | 0.40 | 0.34 | 0.6% | 0.1% | -0.4% | -0.9% |
| 6.27 | 6.03 | 5.34 | 4.39 | 0.9% | 0.7% | 0.3% | -0.3% |
| **12.35** | **11.57** | **10.24** | **8.61** | **0.3%** | **0.1%** | **-0.3%** | **-0.9%** |
| 0.20 | 0.27 | 0.41 | 0.70 | 5.9% | 6.9% | 8.5% | 10.5% |
| | | | | | | | |
| 0.63 | 0.63 | 0.63 | 0.63 | -0.3% | -0.3% | -0.3% | -0.3% |
| 3.59 | 3.68 | 3.65 | 3.68 | 0.4% | 0.4% | 0.4% | 0.5% |
| 0.05 | 0.05 | 0.05 | 0.05 | 0.0% | 0.0% | 0.0% | 0.0% |
| 0.13 | 0.13 | 0.13 | 0.13 | 0.0% | 0.0% | 0.0% | 0.0% |
| 6.06 | 5.72 | 4.63 | 4.22 | 1.0% | 0.8% | 0.1% | -0.2% |
| **10.46** | **10.21** | **9.09** | **8.71** | **0.7%** | **0.6%** | **0.2%** | **0.0%** |
| 0.26 | 0.32 | 0.50 | 0.57 | 2.8% | 3.7% | 5.2% | 5.7% |
| | | | | | | | |
| 2.38 | 2.30 | 2.26 | 2.34 | 0.4% | 0.3% | 0.3% | 0.4% |
| 0.46 | 0.46 | 0.47 | 0.47 | 0.5% | 0.6% | 0.6% | 0.6% |
| 1.64 | 1.22 | 1.09 | 1.19 | 1.1% | 0.0% | -0.4% | 0.0% |
| 1.11 | 1.09 | 1.06 | 1.07 | 0.8% | 0.7% | 0.7% | 0.7% |
| 4.49 | 4.08 | 3.84 | 4.05 | 0.4% | 0.1% | -0.1% | 0.0% |
| 10.08 | 9.16 | 8.72 | 9.12 | 0.6% | 0.2% | 0.1% | 0.2% |
| 11.65 | 10.38 | 10.22 | 10.26 | 1.2% | 0.8% | 0.7% | 0.7% |
| 1.67 | 1.61 | 1.60 | 1.63 | 0.1% | 0.0% | 0.0% | 0.0% |
| 3.48 | 3.65 | 3.89 | 3.67 | 1.6% | 1.8% | 2.0% | 1.8% |
| 4.63 | 3.91 | 3.69 | 4.00 | 1.1% | 0.6% | 0.4% | 0.6% |
| **31.52** | **28.71** | **28.12** | **28.68** | **0.9%** | **0.6%** | **0.5%** | **0.6%** |
| | | | | | | | |
| 0.15 | 0.17 | 0.18 | 0.18 | 3.9% | 4.3% | 4.7% | 4.6% |
| 12.67 | 12.64 | 12.64 | 12.64 | -0.9% | -0.9% | -0.9% | -0.9% |
| 3.42 | 3.42 | 3.29 | 3.42 | 0.4% | 0.4% | 0.3% | 0.4% |
| 8.05 | 7.90 | 7.52 | 7.67 | 1.1% | 1.0% | 0.8% | 0.9% |
| 1.12 | 1.11 | 1.10 | 1.11 | 0.2% | 0.2% | 0.2% | 0.2% |
| 25.40 | 25.24 | 24.74 | 25.02 | -0.1% | -0.1% | -0.2% | -0.2% |
| 0.81 | 0.78 | 0.72 | 0.72 | 0.5% | 0.4% | 0.1% | 0.1% |
| 0.96 | 1.05 | 0.80 | 1.20 | 11.5% | 11.9% | 10.8% | 12.4% |
| 0.00 | 0.00 | 0.00 | 0.00 | - - | - - | - - | - - |
| 0.07 | 0.07 | 0.07 | 0.07 | 3.9% | 3.9% | 3.9% | 3.9% |
| **27.25** | **27.14** | **26.34** | **27.01** | **0.0%** | **0.0%** | **-0.1%** | **0.0%** |
| | | | | | | | |
| 0.20 | 0.19 | 0.17 | 0.16 | -1.4% | -1.6% | -1.9% | -2.2% |
| 9.99 | 9.70 | 8.13 | 7.86 | 0.9% | 0.8% | 0.2% | 0.0% |
| 19.57 | 18.68 | 16.63 | 14.23 | 0.3% | 0.1% | -0.3% | -0.8% |
| 10.22 | 9.44 | 8.99 | 8.89 | 0.7% | 0.5% | 0.3% | 0.3% |
| 9.35 | 7.44 | 6.12 | 5.91 | 2.4% | 1.6% | 0.9% | 0.8% |
| 0.09 | 0.06 | 0.04 | 0.04 | -1.3% | -2.4% | -3.9% | -3.9% |
| **49.64** | **45.73** | **40.31** | **37.32** | **0.8%** | **0.5%** | **0.1%** | **-0.2%** |
| | | | | | | | |
| 37.23 | 36.07 | 35.06 | 35.67 | 0.0% | -0.1% | -0.2% | -0.1% |
| 31.62 | 29.83 | 27.22 | 26.84 | 0.8% | 0.6% | 0.3% | 0.3% |
| 21.29 | 20.35 | 18.29 | 15.91 | 0.3% | 0.1% | -0.2% | -0.7% |
| 10.22 | 9.44 | 8.99 | 8.89 | 0.7% | 0.5% | 0.3% | 0.3% |
| 13.49 | 11.66 | 10.54 | 10.05 | 2.0% | 1.5% | 1.2% | 1.0% |
| 0.32 | 0.29 | 0.27 | 0.27 | -0.4% | -0.6% | -0.9% | -0.9% |
| **114.18** | **107.64** | **100.37** | **97.64** | **0.5%** | **0.3%** | **0.1%** | **0.0%** |

## Table D1. Key results for demand sector technology cases (continued)

| Consumption, emissions, combined heat and power capacity and generation | 2011 | 2020 | | | | 2030 | | | |
|---|---|---|---|---|---|---|---|---|---|
| | | 2012 Demand Technology | Reference | High Demand Technology | Best Available Demand Technology | 2012 Demand Technology | Reference | High Demand Technology | Best Available Demand Technology |
| **Carbon dioxide emissions (million metric tons)** | | | | | | | | | |
| by sector | | | | | | | | | |
| Residential | 335 | 324 | 317 | 301 | 282 | 316 | 299 | 272 | 241 |
| Commercial | 225 | 230 | 232 | 230 | 232 | 234 | 236 | 234 | 236 |
| Industrial[5] | 905 | 1,039 | 999 | 988 | 996 | 1,086 | 1,005 | 987 | 1,007 |
| Transportation | 1,841 | 1,827 | 1,826 | 1,801 | 1,819 | 1,761 | 1,759 | 1,721 | 1,754 |
| Electric power[11] | 2,166 | 2,167 | 2,081 | 1,884 | 1,707 | 2,347 | 2,224 | 1,947 | 1,746 |
| by fuel | | | | | | | | | |
| Petroleum[17] | 2,299 | 2,287 | 2,270 | 2,232 | 2,254 | 2,206 | 2,169 | 2,116 | 2,153 |
| Natural gas | 1,294 | 1,437 | 1,404 | 1,367 | 1,349 | 1,567 | 1,468 | 1,357 | 1,331 |
| Coal | 1,867 | 1,851 | 1,769 | 1,595 | 1,421 | 1,959 | 1,874 | 1,676 | 1,489 |
| Other[18] | 11 | 11 | 11 | 11 | 11 | 11 | 11 | 11 | 11 |
| **Total carbon dioxide emissions** | **5,471** | **5,587** | **5,455** | **5,205** | **5,035** | **5,743** | **5,523** | **5,161** | **4,984** |
| Residential delivered energy intensity (million Btu per household) | 97 | 88 | 86 | 80 | 74 | 83 | 80 | 71 | 62 |
| Commercial delivered energy intensity (thousand Btu per square foot) | 105 | 102 | 100 | 96 | 94 | 100 | 97 | 89 | 86 |
| Industrial delivered energy intensity (thousand Btu per 2005 dollars) | 3.99 | 3.53 | 3.42 | 3.40 | 3.43 | 3.23 | 3.04 | 3.01 | 3.06 |
| **Residential sector generation** | | | | | | | | | |
| **Net summer generation capacity (megawatts)** | | | | | | | | | |
| Natural gas | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Solar photovoltaic | 1,036 | 8,291 | 8,976 | 9,446 | 10,335 | 8,686 | 10,289 | 13,004 | 19,236 |
| Wind | 108 | 302 | 750 | 762 | 809 | 302 | 750 | 762 | 809 |
| **Electricity generation (billion kilowatthours)** | | | | | | | | | |
| Natural gas | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| Solar photovoltaic | 1.63 | 12.72 | 14.01 | 14.75 | 16.14 | 13.35 | 16.10 | 20.53 | 30.54 |
| Wind | 0.15 | 0.43 | 1.08 | 1.09 | 1.16 | 0.43 | 1.08 | 1.09 | 1.16 |
| **Commercial sector generation** | | | | | | | | | |
| **Net summer generation capacity (megawatts)** | | | | | | | | | |
| Natural gas | 843 | 1,478 | 1,609 | 2,107 | 2,220 | 2,696 | 3,734 | 5,284 | 5,764 |
| Solar photovoltaic | 1,975 | 6,604 | 6,646 | 6,692 | 6,770 | 7,698 | 8,644 | 9,203 | 10,237 |
| Wind | 97 | 108 | 118 | 120 | 124 | 132 | 302 | 283 | 309 |
| **Electricity generation (billion kilowatthours)** | | | | | | | | | |
| Natural gas | 6.13 | 10.75 | 11.70 | 15.32 | 16.15 | 19.61 | 27.16 | 38.44 | 41.93 |
| Solar photovoltaic | 3.07 | 10.34 | 10.50 | 10.57 | 10.70 | 12.08 | 13.79 | 14.72 | 16.39 |
| Wind | 0.12 | 0.14 | 0.15 | 0.16 | 0.16 | 0.17 | 0.43 | 0.40 | 0.44 |

[1]Includes propane, kerosene, and distillate fuel oil.
[2]Includes wood used for residential heating.
[3]Includes propane, motor gasoline (including ethanol (blends of 15 percent or less) and ethers blended in), kerosene, distillate fuel oil, and residual fuel oil.
[4]Includes commercial sector consumption of wood and wood waste, landfill gas, municipal solid waste, and other biomass for combined heat and power.
[5]Includes energy for combined heat and power plants that have a non-regulatory status, and small on-site generating systems.
[6]Includes motor gasoline (including ethanol (blends of 15 percent or less) and ethers blended in), residual fuel oil, petroleum coke, asphalt, road oil, lubricants, still gas, and miscellaneous petroleum products.
[7]Includes consumption of energy produced from hydroelectric, wood and wood waste, municipal waste, and other biomass sources. Excludes ethanol.
[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 (blends of 15 percent or less) and ethers blended into gasoline.
[10]Includes propane, residual fuel oil, aviation gasoline, and lubricants.
[11]Includes consumption of energy by electricity-only and combined heat and power plants that have a regulatory status.
[12]These values represent the energy obtained from uranium when it is used in light water reactors. The total energy content of uranium is much larger, but alternative processes are required to take advantage of it.
[13]Includes conventional hydroelectric, geothermal, wood and wood waste, biogenic municipal waste, other biomass, wind, photovoltaic, and solar thermal sources. Excludes net electricity imports.
[14]Includes non-biogenic municipal waste not included above.
[15]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 water heaters.
[16]Includes non-biogenic municipal waste, liquid hydrogen, and net electricity imports.
[17]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 2009, international bunker fuels accounted for 90 to 126 million metric tons annually.
[18]Includes emissions from geothermal power and nonbiogenic emissions from municipal waste.
Btu = British thermal unit.
- - = Not applicable.
Note: Totals may not equal sum of components due to independent rounding. Data for 2011 are model results and may differ slightly from official EIA data reports.
**Source:** U.S. Energy Information Administration, AEO2013 National Energy Modeling System, runs FROZTECH.D120712A, REF2013.D102312A, HIGHTECH.D120712A, and BESTTECH.D121012A.

| 2040 | | | | Annual Growth 2011-2040 (percent) | | | |
|---|---|---|---|---|---|---|---|
| 2012 Demand Technology | Reference | High Demand Technology | Best Available Demand Technology | 2012 Demand Technology | Reference | High Demand Technology | Best Available Demand Technology |
| 307 | 282 | 250 | 215 | -0.3% | -0.6% | -1.0% | -1.5% |
| 240 | 245 | 243 | 245 | 0.2% | 0.3% | 0.3% | 0.3% |
| 1,157 | 1,040 | 1,011 | 1,033 | 0.8% | 0.5% | 0.4% | 0.5% |
| 1,818 | 1,809 | 1,756 | 1,796 | 0.0% | -0.1% | -0.2% | -0.1% |
| 2,416 | 2,315 | 2,036 | 1,792 | 0.4% | 0.2% | -0.2% | -0.7% |
| 2,236 | 2,175 | 2,114 | 2,145 | -0.1% | -0.2% | -0.3% | -0.2% |
| 1,665 | 1,569 | 1,431 | 1,411 | 0.9% | 0.7% | 0.3% | 0.3% |
| 2,025 | 1,936 | 1,739 | 1,514 | 0.3% | 0.1% | -0.2% | -0.7% |
| 11 | 11 | 11 | 11 | 0.0% | 0.0% | 0.0% | 0.0% |
| **5,938** | **5,691** | **5,296** | **5,081** | **0.3%** | **0.1%** | **-0.1%** | **-0.3%** |
| 81 | 76 | 67 | 56 | -0.6% | -0.9% | -1.3% | -1.9% |
| 96 | 94 | 84 | 80 | -0.3% | -0.4% | -0.8% | -0.9% |
| 2.97 | 2.74 | 2.72 | 2.76 | -1.0% | -1.3% | -1.3% | -1.3% |
| 2 | 2 | 2 | 2 | - - | - - | - - | - - |
| 9,649 | 12,927 | 20,651 | 37,759 | 8.0% | 9.1% | 10.9% | 13.2% |
| 303 | 751 | 764 | 818 | 3.6% | 6.9% | 7.0% | 7.2% |
| 0.00 | 0.00 | 0.00 | 0.00 | - - | - - | - - | - - |
| 14.84 | 20.38 | 32.96 | 60.49 | 7.9% | 9.1% | 10.9% | 13.3% |
| 0.43 | 1.08 | 1.10 | 1.17 | 3.7% | 7.0% | 7.0% | 7.3% |
| 4,951 | 8,437 | 12,017 | 12,626 | 6.3% | 8.3% | 9.5% | 9.7% |
| 10,091 | 12,141 | 14,213 | 19,129 | 5.8% | 6.5% | 7.0% | 8.1% |
| 334 | 762 | 765 | 950 | 4.4% | 7.4% | 7.4% | 8.2% |
| 36.01 | 61.37 | 87.42 | 91.85 | 6.3% | 8.3% | 9.5% | 9.7% |
| 15.85 | 19.56 | 22.95 | 30.74 | 5.8% | 6.6% | 7.2% | 8.3% |
| 0.47 | 1.07 | 1.07 | 1.32 | 4.7% | 7.7% | 7.7% | 8.5% |

## Table D2. Energy consumption and carbon dioxide emissions for extended policy cases

| Consumption and emissions | 2011 | 2020 | | | 2030 | | | 2040 | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | | Reference | No Sunset | Extended Policies | Reference | No Sunset | Extended Policies | Reference | No Sunset | Extended Policies |
| **Energy consumption by sector (quadrillion Btu)** | | | | | | | | | | |
| Residential | 11.28 | 10.95 | 10.91 | 10.72 | 11.20 | 11.01 | 10.41 | 11.57 | 11.29 | 10.37 |
| Commercial | 8.60 | 8.95 | 8.95 | 8.85 | 9.54 | 9.55 | 9.17 | 10.21 | 10.26 | 9.67 |
| Industrial[1] | 24.04 | 26.87 | 26.90 | 26.88 | 27.40 | 27.51 | 27.45 | 28.71 | 28.98 | 28.56 |
| Transportation | 27.09 | 27.24 | 27.23 | 27.21 | 26.25 | 26.25 | 25.99 | 27.14 | 27.17 | 26.06 |
| Electric power[2] | 39.40 | 40.57 | 40.38 | 39.64 | 43.02 | 42.69 | 41.16 | 45.73 | 45.70 | 43.63 |
| **Total** | **97.70** | **101.04** | **100.89** | **100.06** | **102.81** | **102.62** | **100.33** | **107.64** | **107.92** | **103.54** |
| **Energy consumption by fuel (quadrillion Btu)** | | | | | | | | | | |
| Liquid fuels and other petroleum[3] | 37.02 | 37.54 | 37.54 | 37.50 | 36.08 | 36.10 | 35.78 | 36.07 | 36.10 | 34.76 |
| Natural gas | 24.91 | 26.77 | 26.71 | 26.60 | 27.95 | 27.60 | 26.82 | 29.83 | 28.60 | 27.54 |
| Coal | 19.66 | 18.59 | 18.35 | 17.84 | 19.70 | 19.20 | 18.45 | 20.35 | 19.84 | 19.00 |
| Nuclear / uranium | 8.26 | 9.25 | 9.25 | 9.25 | 9.49 | 9.49 | 9.49 | 9.44 | 9.08 | 9.02 |
| Renewable energy[4] | 7.49 | 8.58 | 8.74 | 8.57 | 9.31 | 9.98 | 9.52 | 11.66 | 14.03 | 12.95 |
| Other[5] | 0.35 | 0.31 | 0.31 | 0.31 | 0.28 | 0.26 | 0.26 | 0.29 | 0.28 | 0.27 |
| **Total** | **97.70** | **101.04** | **100.89** | **100.06** | **102.81** | **102.62** | **100.33** | **107.64** | **107.92** | **103.54** |
| **Energy intensity (thousand Btu per 2005 dollar of GDP)** | 7.35 | 5.99 | 5.98 | 5.94 | 4.81 | 4.80 | 4.70 | 3.95 | 3.95 | 3.80 |
| **Carbon dioxide emissions by sector (million metric tons)** | | | | | | | | | | |
| Residential | 335 | 317 | 317 | 315 | 299 | 298 | 285 | 282 | 280 | 256 |
| Commercial | 225 | 232 | 232 | 230 | 236 | 238 | 229 | 245 | 248 | 233 |
| Industrial[1] | 905 | 999 | 1,000 | 999 | 1,005 | 1,009 | 1,000 | 1,040 | 1,051 | 1,025 |
| Transportation | 1,841 | 1,826 | 1,826 | 1,824 | 1,759 | 1,759 | 1,742 | 1,809 | 1,810 | 1,736 |
| Electric power[2] | 2,166 | 2,081 | 2,052 | 2,001 | 2,224 | 2,152 | 2,065 | 2,315 | 2,187 | 2,103 |
| **Total** | **5,471** | **5,455** | **5,428** | **5,370** | **5,523** | **5,456** | **5,321** | **5,691** | **5,575** | **5,353** |
| **Carbon dioxide emissions by fuel (million metric tons)** | | | | | | | | | | |
| Petroleum | 2,299 | 2,270 | 2,269 | 2,267 | 2,169 | 2,169 | 2,146 | 2,175 | 2,173 | 2,086 |
| Natural gas | 1,294 | 1,404 | 1,401 | 1,395 | 1,468 | 1,449 | 1,408 | 1,569 | 1,504 | 1,448 |
| Coal | 1,867 | 1,769 | 1,746 | 1,698 | 1,874 | 1,826 | 1,756 | 1,936 | 1,887 | 1,807 |
| Other[6] | 11 | 11 | 11 | 11 | 11 | 11 | 11 | 11 | 11 | 11 |
| **Total** | **5,471** | **5,455** | **5,428** | **5,370** | **5,523** | **5,456** | **5,321** | **5,691** | **5,575** | **5,353** |
| **Carbon dioxide emissions (tons per person)** | **17.5** | **16.0** | **15.9** | **15.8** | **14.8** | **14.6** | **14.3** | **14.1** | **13.8** | **13.2** |

[1]Includes combined heat and power plants that have a non-regulatory status, and small on-site generating systems.
[2]Includes electricity-only and combined heat and power plants that have a regulatory status.
[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 and crude oil consumed as a fuel.
[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, net electricity imports, and liquid hydrogen.
[6]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 2011 are model results and may differ slightly from official EIA data reports.
**Source:** U.S. Energy Information Administration, AEO2013 National Energy Modeling System runs REF2013.D102312A, NOSUNSET.D120712A, and EXTENDED.D041713A.

## Table D3. Electricity generation and generating capacity in extended policy cases
(gigawatts, unless otherwise noted)

| Net summer capacity, generation, consumption, and emissions | 2011 | 2020 | | | 2030 | | | 2040 | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | | Reference | No Sunset | Extended Policies | Reference | No Sunset | Extended Policies | Reference | No Sunset | Extended Policies |
| **Capacity** | **1,048.8** | **1,068.1** | **1,071.3** | **1,038.6** | **1,147.0** | **1,167.8** | **1,102.4** | **1,293.3** | **1,378.0** | **1,264.3** |
| Electric power sector[1] | 1,018.1 | 1,019.6 | 1,013.5 | 980.4 | 1,085.8 | 1,070.5 | 1,005.5 | 1,212.3 | 1,233.0 | 1,121.3 |
| Pulverized coal | 313.9 | 271.0 | 262.4 | 252.1 | 270.1 | 262.1 | 251.8 | 271.3 | 262.1 | 251.8 |
| Coal gasification combined-cycle | 0.5 | 2.0 | 2.0 | 2.0 | 2.0 | 2.0 | 2.0 | 2.0 | 2.0 | 2.0 |
| Oil and natural gas steam | 102.7 | 87.2 | 84.7 | 72.9 | 69.9 | 64.4 | 53.6 | 64.8 | 56.8 | 40.9 |
| Conventional natural gas combined-cycle | 205.5 | 216.7 | 216.7 | 216.4 | 221.8 | 220.4 | 219.3 | 227.6 | 225.1 | 222.3 |
| Advanced natural gas combined-cycle | 0.0 | 2.5 | 1.6 | 1.0 | 42.5 | 26.2 | 17.3 | 86.8 | 57.4 | 43.8 |
| Conventional combustion turbine | 138.9 | 137.8 | 135.4 | 133.7 | 137.1 | 133.8 | 130.4 | 136.9 | 133.3 | 130.2 |
| Advanced combustion turbine | 0.0 | 14.9 | 11.2 | 9.0 | 42.8 | 35.7 | 19.4 | 74.8 | 67.0 | 37.6 |
| Nuclear / uranium | 101.1 | 110.6 | 110.6 | 110.6 | 113.6 | 113.6 | 113.6 | 113.1 | 108.5 | 107.8 |
| Pumped storage | 22.3 | 22.3 | 22.3 | 22.3 | 22.3 | 22.3 | 22.3 | 22.3 | 22.3 | 22.3 |
| Fuel cells | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Renewable sources | 133.1 | 153.8 | 166.1 | 159.9 | 160.5 | 188.1 | 174.6 | 207.6 | 294.8 | 260.6 |
| Distributed generation | 0.0 | 0.9 | 0.6 | 0.4 | 3.1 | 2.0 | 1.2 | 5.1 | 3.6 | 2.0 |
| Combined heat and power[2] | 30.6 | 48.5 | 57.8 | 58.2 | 61.1 | 97.2 | 96.9 | 81.0 | 145.0 | 143.0 |
| Fossil fuels / other | 21.7 | 24.4 | 25.3 | 25.5 | 32.0 | 34.8 | 34.2 | 43.5 | 47.6 | 46.2 |
| Renewable fuels | 8.9 | 24.2 | 32.5 | 32.6 | 29.1 | 62.4 | 62.6 | 37.5 | 97.4 | 96.9 |
| **Cumulative additions** | **0.0** | **87.6** | **103.9** | **94.8** | **182.2** | **219.6** | **178.6** | **339.9** | **443.8** | **359.4** |
| Electric power sector[1] | 0.0 | 69.7 | 76.7 | 67.3 | 151.7 | 153.0 | 112.3 | 289.5 | 329.4 | 247.0 |
| Pulverized coal | 0.0 | 4.9 | 4.9 | 4.9 | 4.9 | 4.9 | 4.9 | 6.1 | 4.9 | 4.9 |
| Coal gasification combined-cycle | 0.0 | 1.5 | 1.5 | 1.5 | 1.5 | 1.5 | 1.5 | 1.5 | 1.5 | 1.5 |
| Conventional natural gas combined-cycle | 0.0 | 11.4 | 11.4 | 11.2 | 16.5 | 15.2 | 14.1 | 22.4 | 19.9 | 17.0 |
| Advanced natural gas combined-cycle | 0.0 | 2.5 | 1.6 | 1.0 | 42.5 | 26.2 | 17.3 | 86.8 | 57.4 | 43.8 |
| Conventional combustion turbine | 0.0 | 6.1 | 5.8 | 5.6 | 6.1 | 5.8 | 5.6 | 6.1 | 5.8 | 5.6 |
| Advanced combustion turbine | 0.0 | 14.9 | 11.2 | 9.0 | 42.8 | 35.7 | 19.4 | 74.8 | 67.0 | 37.6 |
| Nuclear / uranium | 0.0 | 5.5 | 5.5 | 5.5 | 5.5 | 5.5 | 5.5 | 11.0 | 6.5 | 5.7 |
| Renewable sources | 0.0 | 21.8 | 34.2 | 28.0 | 28.6 | 56.2 | 42.7 | 75.7 | 162.9 | 128.7 |
| Distributed generation | 0.0 | 0.9 | 0.6 | 0.4 | 3.1 | 2.0 | 1.2 | 5.1 | 3.6 | 2.0 |
| Combined heat and power[2] | 0.0 | 17.9 | 27.1 | 27.5 | 30.5 | 66.6 | 66.2 | 50.4 | 114.4 | 112.4 |
| Fossil fuels / other | 0.0 | 2.7 | 3.5 | 3.8 | 10.3 | 13.1 | 12.5 | 21.8 | 25.9 | 24.5 |
| Renewable fuels | 0.0 | 15.2 | 23.6 | 23.7 | 20.2 | 53.5 | 53.7 | 28.6 | 88.5 | 87.9 |
| **Cumulative retirements** | **0.0** | **72.7** | **85.9** | **109.5** | **92.0** | **108.6** | **133.0** | **103.4** | **122.6** | **151.9** |
| **Generation by fuel (billion kilowatthours)** | **4,093** | **4,389** | **4,388** | **4,317** | **4,777** | **4,786** | **4,613** | **5,212** | **5,254** | **5,026** |
| Electric power sector[1] | 3,954 | 4,182 | 4,162 | 4,089 | 4,506 | 4,446 | 4,277 | 4,842 | 4,765 | 4,548 |
| Coal | 1,715 | 1,640 | 1,617 | 1,570 | 1,745 | 1,699 | 1,635 | 1,804 | 1,756 | 1,686 |
| Petroleum | 26 | 15 | 15 | 15 | 16 | 15 | 15 | 16 | 16 | 16 |
| Natural gas | 930 | 1,078 | 1,065 | 1,057 | 1,221 | 1,144 | 1,086 | 1,348 | 1,122 | 1,082 |
| Nuclear / uranium | 790 | 885 | 885 | 885 | 908 | 908 | 908 | 903 | 868 | 863 |
| Renewable sources | 489 | 559 | 575 | 558 | 602 | 670 | 625 | 754 | 992 | 894 |
| Pumped storage / other | 4 | 2 | 2 | 2 | 3 | 3 | 3 | 3 | 3 | 3 |
| Distributed generation | 0 | 3 | 2 | 1 | 10 | 7 | 4 | 13 | 8 | 5 |
| Combined heat and power[2] | 139 | 208 | 226 | 228 | 271 | 340 | 336 | 370 | 489 | 478 |
| Fossil fuels / other | 103 | 140 | 145 | 146 | 189 | 205 | 201 | 266 | 290 | 280 |
| Renewable fuels | 36 | 68 | 81 | 82 | 82 | 135 | 136 | 104 | 199 | 198 |
| **Average electricity price (cents per kilowatthour)** | **9.9** | **9.4** | **9.4** | **9.4** | **9.7** | **9.6** | **9.5** | **10.8** | **10.4** | **10.1** |

[1]Includes electricity-only and combined heat and power plants that have a regulatory status.
[2]Includes combined heat and power plants and electricity-only plants in the commercial and industrial sectors that have a non-regulatory status. 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.
Note: Totals may not equal sum of components due to independent rounding. Data for 2011 are model results and may differ slightly from official EIA data reports.
**Source:** U.S. Energy Information Administration, AEO2013 National Energy Modeling System runs REF2013.D102312A, NOSUNSET.D120712A, and EXTENDED.D041713A.

## Table D4. Key results for nuclear plant cases
(gigawatts, unless otherwise noted)

| Net summer capacity, generation, emissions, and fuel prices | 2011 | 2030 | | | | 2040 | | | |
|---|---|---|---|---|---|---|---|---|---|
| | | Low Nuclear | Reference | High Nuclear | Small Modular Reactor | Low Nuclear | Reference | High Nuclear | Small Modular Reactor |
| **Capacity** | | | | | | | | | |
| Coal steam | 314.4 | 273.7 | 272.1 | 272.3 | 271.7 | 278.7 | 273.3 | 273.4 | 272.7 |
| Oil and natural gas steam | 102.7 | 67.3 | 69.9 | 70.4 | 68.7 | 62.0 | 64.8 | 64.8 | 65.1 |
| Combined cycle | 205.5 | 264.4 | 264.3 | 258.3 | 264.0 | 337.0 | 314.4 | 301.3 | 312.8 |
| Combustion turbine / diesel | 138.9 | 183.5 | 179.9 | 179.9 | 182.1 | 218.6 | 211.7 | 218.1 | 212.9 |
| Nuclear / uranium | 101.1 | 102.8 | 113.6 | 121.9 | 113.7 | 62.6 | 113.1 | 127.2 | 115.4 |
| Pumped storage | 22.3 | 22.3 | 22.3 | 22.3 | 22.3 | 22.3 | 22.3 | 22.3 | 22.3 |
| Fuel cells | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Renewable sources | 133.1 | 160.9 | 160.5 | 160.2 | 160.5 | 211.3 | 207.6 | 202.9 | 204.9 |
| Distributed generation | 0.0 | 2.6 | 3.1 | 3.2 | 3.1 | 4.1 | 5.1 | 5.3 | 5.1 |
| Combined heat and power[1] | 30.6 | 61.9 | 61.1 | 61.1 | 61.2 | 83.4 | 81.0 | 80.4 | 81.1 |
| **Total** | **1,048.8** | **1,139.6** | **1,147.0** | **1,149.6** | **1,147.4** | **1,280.1** | **1,293.3** | **1,295.9** | **1,292.3** |
| **Cumulative additions** | | | | | | | | | |
| Coal steam | 0.0 | 6.4 | 6.4 | 6.4 | 6.4 | 11.4 | 7.6 | 7.5 | 7.5 |
| Oil and natural gas steam | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Combined cycle | 0.0 | 59.2 | 59.0 | 53.1 | 58.8 | 131.8 | 109.1 | 96.1 | 107.6 |
| Combustion turbine / diesel | 0.0 | 51.9 | 48.9 | 48.4 | 51.3 | 87.0 | 80.9 | 86.7 | 82.5 |
| Nuclear / uranium | 0.0 | 5.5 | 5.5 | 13.3 | 5.6 | 5.5 | 11.0 | 18.7 | 13.3 |
| Pumped storage | 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 |
| Renewable sources | 0.0 | 29.0 | 28.6 | 28.3 | 28.6 | 79.4 | 75.7 | 71.0 | 73.0 |
| Distributed generation | 0.0 | 2.6 | 3.1 | 3.2 | 3.1 | 4.1 | 5.1 | 5.3 | 5.1 |
| Combined heat and power[1] | 0.0 | 31.3 | 30.5 | 30.4 | 30.6 | 52.8 | 50.4 | 49.8 | 50.5 |
| **Total** | **0.0** | **186.0** | **182.2** | **183.1** | **184.5** | **372.0** | **339.9** | **335.1** | **339.5** |
| **Cumulative retirements** | **0.0** | **96.6** | **92.0** | **90.3** | **93.9** | **142.0** | **103.4** | **96.0** | **103.9** |
| **Generation by fuel (billion kilowatthours)** | | | | | | | | | |
| Coal | 1,715 | 1,771 | 1,745 | 1,734 | 1,740 | 1,846 | 1,804 | 1,804 | 1,801 |
| Petroleum | 26 | 16 | 16 | 16 | 16 | 16 | 16 | 16 | 16 |
| Natural gas | 930 | 1,267 | 1,221 | 1,181 | 1,225 | 1,602 | 1,348 | 1,272 | 1,338 |
| Nuclear / uranium | 790 | 824 | 908 | 974 | 909 | 507 | 903 | 1,014 | 921 |
| Pumped storage / other | 4 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 |
| Renewable sources | 489 | 599 | 602 | 600 | 601 | 770 | 754 | 741 | 748 |
| Distributed generation | 0 | 9 | 10 | 10 | 11 | 12 | 13 | 14 | 14 |
| Combined heat and power[1] | 139 | 275 | 271 | 272 | 272 | 381 | 370 | 368 | 370 |
| **Total** | **4,093** | **4,764** | **4,777** | **4,789** | **4,775** | **5,136** | **5,212** | **5,231** | **5,211** |
| **Carbon dioxide emissions by the electric power sector (million metric tons)[2]** | | | | | | | | | |
| Petroleum | 25 | 14 | 14 | 14 | 14 | 14 | 14 | 14 | 14 |
| Natural gas | 411 | 500 | 482 | 468 | 483 | 602 | 514 | 489 | 511 |
| Coal | 1,718 | 1,743 | 1,717 | 1,707 | 1,713 | 1,812 | 1,775 | 1,776 | 1,773 |
| Other[3] | 11 | 11 | 11 | 11 | 11 | 11 | 11 | 11 | 11 |
| **Total** | **2,166** | **2,267** | **2,224** | **2,201** | **2,221** | **2,440** | **2,315** | **2,291** | **2,310** |
| **Prices to the electric power sector[2] (2011 dollars per million Btu)** | | | | | | | | | |
| Petroleum | 17.49 | 28.20 | 28.23 | 28.24 | 28.18 | 33.49 | 33.49 | 33.47 | 33.47 |
| Natural gas | 4.77 | 6.20 | 6.05 | 5.95 | 6.07 | 9.36 | 8.38 | 8.36 | 8.51 |
| Coal | 2.38 | 2.88 | 2.87 | 2.86 | 2.86 | 3.23 | 3.20 | 3.20 | 3.20 |

[1]Includes combined heat and power plants and electricity-only plants in commercial and industrial sectors that have a non-regulatory status. 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 that have a regulatory status.
[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 2011 are model results and may differ slightly from official EIA data reports.
**Source:** U.S. Energy Information Administration, AEO2013 National Energy Modeling System runs LOWNUC13.D112112A, REF2013.D102312A, HINUC13.D112112A, and NUCSMR13.D112712A.

## Table D5. Key results for renewable technology case

| Capacity, generation, and emissions | 2011 | 2020 Reference | 2020 Low Renewable Technology Cost | 2030 Reference | 2030 Low Renewable Technology Cost | 2040 Reference | 2040 Low Renewable Technology Cost |
|---|---|---|---|---|---|---|---|
| **Net summer capacity (gigawatts)** | | | | | | | |
| **Electric power sector[1]** | | | | | | | |
| Conventional hydropower | 77.87 | 78.34 | 78.68 | 79.11 | 79.75 | 80.31 | 82.06 |
| Geothermal[2] | 2.38 | 3.63 | 3.37 | 5.70 | 6.20 | 7.46 | 7.94 |
| Municipal waste[3] | 3.34 | 3.44 | 3.44 | 3.44 | 3.44 | 3.44 | 3.44 |
| Wood and other biomass[4] | 2.37 | 2.82 | 2.81 | 2.85 | 3.22 | 3.70 | 6.18 |
| Solar thermal | 0.49 | 1.35 | 1.35 | 1.35 | 1.35 | 1.35 | 1.35 |
| Solar photovoltaic | 1.01 | 5.37 | 10.15 | 6.80 | 15.08 | 24.54 | 45.95 |
| Wind | 45.68 | 58.81 | 64.67 | 61.30 | 70.37 | 86.83 | 116.68 |
| **Total** | **133.14** | **153.75** | **164.48** | **160.54** | **179.40** | **207.63** | **263.61** |
| **End-use sector[5]** | | | | | | | |
| Conventional hydropower | 0.33 | 0.33 | 0.33 | 0.33 | 0.33 | 0.33 | 0.33 |
| Geothermal | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| Municipal waste[6] | 0.46 | 0.46 | 0.46 | 0.46 | 0.46 | 0.46 | 0.46 |
| Wood and other biomass | 4.92 | 6.87 | 7.61 | 8.34 | 10.36 | 10.18 | 14.01 |
| Solar photovoltaic | 3.02 | 15.63 | 16.81 | 18.94 | 23.22 | 25.08 | 33.51 |
| Wind | 0.21 | 0.87 | 1.36 | 1.05 | 1.73 | 1.51 | 2.84 |
| **Total** | **8.93** | **24.15** | **26.55** | **29.12** | **36.10** | **37.55** | **51.15** |
| **Generation (billion kilowatthours)** | | | | | | | |
| **Electric power sector[1]** | | | | | | | |
| Coal | 1,715 | 1,640 | 1,609 | 1,745 | 1,709 | 1,804 | 1,758 |
| Petroleum | 26 | 15 | 15 | 16 | 16 | 16 | 16 |
| Natural gas | 930 | 1,078 | 1,062 | 1,221 | 1,184 | 1,348 | 1,238 |
| **Total fossil** | 2,671 | 2,733 | 2,686 | 2,982 | 2,908 | 3,169 | 3,013 |
| Conventional hydropower | 323.14 | 288.54 | 290.00 | 292.39 | 295.25 | 297.28 | 303.59 |
| Geothermal | 16.70 | 25.28 | 23.25 | 42.02 | 46.15 | 56.40 | 60.51 |
| Municipal waste[7] | 16.62 | 14.09 | 14.09 | 14.09 | 14.09 | 14.10 | 14.10 |
| Wood and other biomass[4] | 10.50 | 54.45 | 72.77 | 65.48 | 86.74 | 75.64 | 113.52 |
| Dedicated plants | 9.35 | 14.85 | 14.75 | 15.30 | 17.96 | 21.59 | 39.64 |
| Cofiring | 1.16 | 39.60 | 58.03 | 50.18 | 68.78 | 54.05 | 73.88 |
| Solar thermal | 0.81 | 2.74 | 2.74 | 2.73 | 2.74 | 2.73 | 2.73 |
| Solar photovoltaic | 0.97 | 9.83 | 20.85 | 13.40 | 32.67 | 56.22 | 105.76 |
| Wind | 119.63 | 163.48 | 182.60 | 172.11 | 199.32 | 251.94 | 340.16 |
| **Total renewable** | **488.38** | **558.41** | **606.30** | **602.22** | **676.96** | **754.32** | **940.37** |
| **End-use sector[5]** | | | | | | | |
| **Total fossil** | 88 | 122 | 122 | 171 | 169 | 248 | 242 |
| Conventional hydropower[8] | 1.89 | 1.82 | 1.82 | 1.82 | 1.82 | 1.82 | 1.82 |
| Geothermal | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| Municipal waste[6] | 2.04 | 3.55 | 3.55 | 3.55 | 3.55 | 3.55 | 3.55 |
| Wood and other biomass | 26.75 | 36.95 | 40.54 | 45.55 | 56.25 | 56.25 | 77.56 |
| Solar photovoltaic | 4.71 | 24.53 | 26.37 | 29.91 | 36.82 | 39.97 | 53.71 |
| Wind | 0.28 | 1.23 | 1.87 | 1.50 | 2.41 | 2.15 | 3.93 |
| **Total renewable** | **35.68** | **68.09** | **74.14** | **82.33** | **100.85** | **103.74** | **140.57** |
| **Carbon dioxide emissions by the electric power sector (million metric tons)[1]** | | | | | | | |
| Coal | 1,718 | 1,610 | 1,580 | 1,717 | 1,681 | 1,775 | 1,730 |
| Petroleum | 25 | 13 | 13 | 14 | 14 | 14 | 14 |
| Natural gas | 411 | 446 | 440 | 482 | 471 | 514 | 476 |
| Other[9] | 11 | 11 | 11 | 11 | 11 | 11 | 11 |
| **Total** | **2,166** | **2,081** | **2,044** | **2,224** | **2,177** | **2,315** | **2,232** |

[1]Includes electricity-only and combined heat and power plants that have a regulatory status.
[2]Includes both hydrothermal resources (hot water and steam) and near-field enhanced geothermal systems (EGS). Near-field EGS potential occurs on known hydrothermal sites, however this potential requires the addition of external fluids for electricity generation and is only available after 2025.
[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]Facilities co-firing biomass and coal are classified as coal.
[5]Includes combined heat and power plants and electricity-only plants in the commercial and industrial sectors that have a non-regulatory status. 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.
[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 2011 are model results and may differ slightly from official EIA data reports.
**Source:** U.S. Energy Information Administration, AEO2013 National Energy Modeling System runs REF2013.D102312A, and LCR20.D112012A.

## Table D6. Key results for environmental cases

| Net summer capacity, generation, emissions, and fuel prices | 2011 | 2040 Reference | 2040 GHG10 | 2040 GHG15 | 2040 GHG25 | 2040 High Oil and Gas Resource | 2040 GHG10 and Low Gas Prices | 2040 GHG15 and Low Gas Prices | 2040 GHG25 and Low Gas Prices |
|---|---|---|---|---|---|---|---|---|---|
| **Capacity (gigawatts)** | | | | | | | | | |
| Coal steam | 314.4 | 273.3 | 219.6 | 120.1 | 28.8 | 248.0 | 145.5 | 80.7 | 29.5 |
| Oil and natural gas steam | 102.7 | 64.8 | 51.7 | 37.9 | 26.0 | 68.5 | 57.6 | 56.2 | 19.9 |
| Combined cycle | 205.5 | 314.4 | 312.8 | 336.2 | 368.3 | 343.6 | 433.4 | 458.7 | 517.1 |
| Combustion turbine / diesel | 138.9 | 211.7 | 200.3 | 192.5 | 174.0 | 250.3 | 213.4 | 201.5 | 176.7 |
| Nuclear / uranium | 101.1 | 113.1 | 137.3 | 166.5 | 226.6 | 106.5 | 115.9 | 130.7 | 150.5 |
| Pumped storage | 22.3 | 22.3 | 22.3 | 22.3 | 22.3 | 22.3 | 22.3 | 22.3 | 22.3 |
| Renewable sources | 133.1 | 207.6 | 264.4 | 375.5 | 439.0 | 162.3 | 197.2 | 260.7 | 325.5 |
| Distributed generation | 0.0 | 5.1 | 0.2 | 0.0 | 0.0 | 28.2 | 0.3 | 0.1 | 0.0 |
| Combined heat and power[1] | 30.6 | 81.0 | 91.8 | 99.1 | 108.3 | 85.1 | 93.2 | 96.4 | 103.2 |
| **Total** | **1,048.8** | **1,293.3** | **1,300.4** | **1,350.2** | **1,393.3** | **1,314.8** | **1,278.8** | **1,307.2** | **1,344.6** |
| **Cumulative additions (gigawatts)** | | | | | | | | | |
| Coal steam | 0.0 | 7.6 | 6.4 | 7.2 | 6.5 | 6.4 | 6.4 | 6.4 | 6.4 |
| Combined cycle | 0.0 | 109.1 | 107.6 | 131.0 | 163.0 | 138.4 | 228.1 | 253.5 | 311.8 |
| Combustion turbine / diesel | 0.0 | 80.9 | 70.5 | 69.1 | 71.1 | 116.3 | 82.0 | 72.9 | 72.7 |
| Nuclear / uranium | 0.0 | 11.0 | 35.3 | 64.4 | 124.6 | 5.5 | 13.9 | 28.6 | 48.5 |
| Renewable sources | 0.0 | 75.7 | 132.5 | 243.6 | 307.1 | 30.4 | 65.3 | 128.8 | 193.6 |
| Distributed generation | 0.0 | 5.1 | 0.2 | 0.0 | 0.0 | 28.2 | 0.3 | 0.1 | 0.0 |
| Combined heat and power[1] | 0.0 | 50.4 | 61.2 | 68.5 | 77.6 | 54.5 | 62.6 | 65.8 | 72.5 |
| **Total** | **0.0** | **339.9** | **413.6** | **583.9** | **750.0** | **379.7** | **458.6** | **556.0** | **705.5** |
| **Cumulative retirements (gigawatts)** | **0.0** | **103.4** | **170.0** | **290.5** | **413.5** | **121.7** | **236.5** | **305.6** | **417.7** |
| **Generation by fuel (billion kilowatthours)** | | | | | | | | | |
| Coal | 1,715 | 1,804 | 1,190 | 602 | 61 | 1,426 | 550 | 176 | 32 |
| Petroleum | 26 | 16 | 15 | 12 | 10 | 16 | 12 | 10 | 10 |
| Natural gas | 930 | 1,348 | 1,240 | 1,263 | 1,105 | 1,971 | 2,473 | 2,491 | 2,189 |
| Nuclear / uranium | 790 | 903 | 1,091 | 1,317 | 1,788 | 853 | 925 | 1,039 | 1,195 |
| Pumped storage / other | 4 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 |
| Renewable sources | 489 | 754 | 1,070 | 1,277 | 1,382 | 633 | 772 | 912 | 1,077 |
| Distributed generation | 0 | 13 | 0 | 0 | 0 | 122 | 0 | 0 | 0 |
| Combined heat and power[1] | 139 | 370 | 417 | 437 | 463 | 409 | 441 | 452 | 473 |
| **Total** | **4,093** | **5,212** | **5,026** | **4,911** | **4,812** | **5,432** | **5,177** | **5,083** | **4,977** |
| **Emissions by the electric power sector[2]** | | | | | | | | | |
| Carbon dioxide (million metric tons) | 2,166 | 2,315 | 1,639 | 1,034 | 360 | 2,227 | 1,444 | 1,056 | 544 |
| Sulfur dioxide (million short tons) | 4.42 | 1.66 | 0.90 | 0.47 | 0.06 | 1.09 | 0.40 | 0.13 | 0.04 |
| Nitrogen oxides (million short tons) | 1.94 | 1.87 | 1.31 | 0.70 | 0.26 | 1.56 | 0.72 | 0.41 | 0.30 |
| Mercury (short tons) | 31.49 | 7.75 | 5.32 | 2.81 | 0.53 | 6.16 | 2.39 | 0.97 | 0.37 |
| **Retrofits (gigawatts)** | | | | | | | | | |
| Scrubber | 0.00 | 33.87 | 36.06 | 20.75 | 15.76 | 33.92 | 22.05 | 17.32 | 14.36 |
| Nitrogen oxide controls | | | | | | | | | |
| Combustion | 0.00 | 0.79 | 0.79 | 0.79 | 0.01 | 0.78 | 0.00 | 0.01 | 0.00 |
| Selective catalytic reduction post-combustion | 0.00 | 13.90 | 12.28 | 13.65 | 14.17 | 13.52 | 14.12 | 12.28 | 12.31 |
| Selective non-catalytic reduction post-combustion | 0.00 | 0.70 | 1.22 | 1.17 | 0.70 | 2.51 | 1.17 | 0.70 | 0.70 |
| **Prices to the electric power sector[2] (2011 dollars per million Btu)** | | | | | | | | | |
| Natural gas | 4.77 | 8.38 | 10.03 | 11.01 | 12.87 | 5.13 | 7.47 | 8.47 | 10.40 |
| Coal | 2.38 | 3.20 | 6.38 | 7.71 | 10.58 | 2.91 | 5.83 | 7.25 | 10.75 |

[1]Includes combined heat and power plants and electricity-only plants in the commercial and industrial sectors that have a non-regulatory status. 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 that have a regulatory status.
Btu = British thermal unit.
GHG = Greenhouse gas.
Note: Totals may not equal sum of components due to independent rounding. Data for 2011 are model results and may differ slightly from official EIA data reports.
**Source:** U.S. Energy Information Administration, AEO2013 National Energy Modeling System runs REF2013.D102312A, CO2FEE10.D021413A, CO2FEE15.D021413A, CO2FEE25.D021413A, HIGHRESOURCE.D021413A, CO2FEE10HR.D021413A, CO2FEE15HR.D021413A, and CO2FEE25HR.D021413A.

# Table D7. Natural gas supply and disposition, oil and gas resource cases
(trillion cubic feet per year, unless otherwise noted)

| Supply, disposition, and prices | 2011 | 2020 | | | 2030 | | | 2040 | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | | Low Oil and Gas Resource | Reference | High Oil and Gas Resource | Low Oil and Gas Resource | Reference | High Oil and Gas Resource | Low Oil and Gas Resource | Reference | High Oil and Gas Resource |
| **Henry Hub spot price** | | | | | | | | | | |
| (2011 dollars per million Btu) | 3.98 | 5.37 | 4.13 | 2.72 | 7.05 | 5.40 | 3.26 | 10.36 | 7.83 | 4.32 |
| (2011 dollars per thousand cubic feet) | 4.07 | 5.49 | 4.22 | 2.78 | 7.21 | 5.52 | 3.33 | 10.59 | 8.00 | 4.42 |
| **Dry gas production[1]** | **23.00** | **24.23** | **26.61** | **30.94** | **25.75** | **29.79** | **36.89** | **27.03** | **33.14** | **44.91** |
| Lower 48 onshore | 20.54 | 21.84 | 24.27 | 28.37 | 21.85 | 26.26 | 33.30 | 22.47 | 29.12 | 40.74 |
| Associated-dissolved[2] | 1.54 | 1.78 | 2.14 | 3.00 | 1.24 | 1.43 | 3.05 | 0.93 | 1.09 | 2.70 |
| Non-associated | 19.00 | 20.06 | 22.13 | 25.37 | 20.62 | 24.83 | 30.25 | 21.54 | 28.03 | 38.04 |
| Tight gas | 5.86 | 5.98 | 6.40 | 7.63 | 5.77 | 6.67 | 8.86 | 5.95 | 7.34 | 10.72 |
| Shale gas | 7.85 | 9.29 | 11.05 | 13.18 | 10.40 | 14.17 | 17.56 | 11.14 | 16.70 | 23.93 |
| Coalbed methane | 1.71 | 1.79 | 1.71 | 1.60 | 2.15 | 1.69 | 1.51 | 2.55 | 2.11 | 1.53 |
| Other | 3.58 | 2.99 | 2.97 | 2.96 | 2.30 | 2.31 | 2.32 | 1.90 | 1.87 | 1.86 |
| Lower 48 offshore | 2.11 | 2.11 | 2.07 | 2.29 | 2.70 | 2.34 | 2.37 | 3.38 | 2.85 | 2.92 |
| Associated-dissolved[2] | 0.54 | 0.66 | 0.66 | 0.74 | 0.71 | 0.60 | 0.65 | 0.89 | 0.74 | 0.81 |
| Non-associated | 1.58 | 1.44 | 1.41 | 1.55 | 1.99 | 1.73 | 1.72 | 2.49 | 2.11 | 2.12 |
| Alaska | 0.35 | 0.28 | 0.28 | 0.28 | 1.19 | 1.19 | 1.22 | 1.18 | 1.18 | 1.25 |
| Supplemental natural gas[3] | 0.06 | 0.06 | 0.06 | 0.06 | 0.06 | 0.06 | 0.06 | 0.06 | 0.06 | 0.06 |
| **Net imports** | **1.95** | **0.24** | **-0.14** | **-0.52** | **-0.83** | **-2.10** | **-3.63** | **-2.56** | **-3.55** | **-6.70** |
| Pipeline[4] | 1.67 | 0.50 | 0.13 | -0.26 | 0.04 | -0.67 | -1.57 | -1.39 | -2.09 | -2.84 |
| Liquefied natural gas | 0.28 | -0.26 | -0.26 | -0.26 | -0.87 | -1.43 | -2.06 | -1.17 | -1.46 | -3.86 |
| **Total supply** | **25.01** | **24.53** | **26.54** | **30.48** | **24.98** | **27.75** | **33.33** | **24.53** | **29.65** | **38.27** |
| **Consumption by sector** | | | | | | | | | | |
| Residential | 4.72 | 4.44 | 4.52 | 4.64 | 4.26 | 4.36 | 4.52 | 4.02 | 4.14 | 4.31 |
| Commercial | 3.16 | 3.20 | 3.32 | 3.51 | 3.26 | 3.42 | 3.71 | 3.40 | 3.60 | 3.97 |
| Industrial[5] | 6.77 | 7.52 | 7.68 | 7.96 | 7.55 | 7.79 | 8.04 | 7.59 | 7.90 | 8.14 |
| Natural-gas-to-liquids heat and power[6] | 0.00 | 0.07 | 0.13 | 0.14 | 0.09 | 0.21 | 0.36 | 0.11 | 0.33 | 1.01 |
| Natural gas to liquids production[7] | 0.00 | 0.07 | 0.14 | 0.15 | 0.09 | 0.22 | 0.39 | 0.12 | 0.35 | 1.10 |
| Electric power[8] | 7.60 | 6.87 | 8.23 | 11.27 | 7.23 | 8.89 | 12.89 | 6.13 | 9.50 | 14.78 |
| Transportation[9] | 0.04 | 0.07 | 0.08 | 0.08 | 0.18 | 0.26 | 0.27 | 0.77 | 1.04 | 1.04 |
| Pipeline fuel | 0.68 | 0.66 | 0.70 | 0.78 | 0.67 | 0.73 | 0.85 | 0.66 | 0.76 | 0.97 |
| Lease and plant fuel[10] | 1.39 | 1.42 | 1.54 | 1.74 | 1.46 | 1.70 | 2.12 | 1.59 | 1.93 | 2.79 |
| **Total** | **24.37** | **24.31** | **26.32** | **30.26** | **24.78** | **27.57** | **33.14** | **24.40** | **29.54** | **38.11** |
| Discrepancy[11] | 0.64 | 0.22 | 0.22 | 0.22 | 0.19 | 0.18 | 0.19 | 0.14 | 0.12 | 0.16 |
| **Lower 48 end of year dry reserves[1]** | **298.96** | **308.37** | **332.51** | **398.38** | **321.33** | **350.65** | **435.34** | **330.37** | **359.97** | **450.88** |

[1]Marketed production (wet) minus extraction losses.
[2]Gas which occurs in crude oil reservoirs either as free gas (associated) or as gas in solution with crude oil (dissolved).
[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, as well as gas from Canada and Mexico.
[5]Includes energy for combined heat and power plants that have a non-regulatory status, and small on-site generating systems.
[6]Includes any natural gas used in the process of converting natural gas to liquid fuel that is not actually converted.
[7]Includes any natural gas converted into liquid fuel.
[8]Includes consumption of energy by electricity-only and combined heat and power plants that have a regulatory status.
[9]Natural gas used as a vehicle fuel.
[10]Represents natural gas used in well, field, and lease operations, in natural gas processing plant machinery, and for liquefaction in export facilities.
[11]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, 2011 values include net storage injections.
Note: Totals may not equal sum of components due to independent rounding. Data for 2011 are model results and may differ slightly from official EIA data reports.
**Sources:** 2011 supply values; lease, plant, and pipeline fuel consumption: U.S. Energy Information Administration (EIA), *Natural Gas Monthly*, DOE/EIA-0130(2012/07) (Washington, DC, July 2012). Other 2011 consumption based on: EIA, *Annual Energy Review 2011*, DOE/EIA-0384(2011) (Washington, DC, September 2012). 2011 natural gas price at Henry Hub based on daily spot prices published in Natural Gas Intelligence. **Projections:** EIA, AEO2013 National Energy Modeling System runs LOWRESOURCE.D012813A, REF2013.D102312A, and HIGHRESOURCE.D021413A.

## Table D8. Liquid fuels supply and disposition, oil and gas resource cases
(million barrels per day, unless otherwise noted)

| Supply, disposition, and prices | 2011 | 2020 | | | 2030 | | | 2040 | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | | Low Oil and Gas Resource | Reference | High Oil and Gas Resource | Low Oil and Gas Resource | Reference | High Oil and Gas Resource | Low Oil and Gas Resource | Reference | High Oil and Gas Resource |
| **Crude oil prices** | | | | | | | | | | |
| **(2011 dollars per barrel)** | | | | | | | | | | |
| Brent spot | 111.26 | 107.96 | 105.57 | 98.30 | 132.32 | 130.47 | 117.09 | 165.01 | 162.68 | 143.97 |
| West Texas Intermediate spot | 94.86 | 105.92 | 103.57 | 96.43 | 130.29 | 128.47 | 115.30 | 162.98 | 160.68 | 142.20 |
| Imported crude oil[1] | 102.65 | 104.36 | 102.19 | 95.26 | 126.68 | 125.64 | 112.93 | 157.23 | 154.96 | 136.97 |
| **Crude oil supply** | | | | | | | | | | |
| Domestic production[2] | 5.67 | 6.82 | 7.47 | 9.68 | 5.96 | 6.30 | 9.96 | 5.90 | 6.13 | 10.24 |
| Alaska | 0.57 | 0.49 | 0.49 | 0.54 | 0.38 | 0.38 | 0.69 | 0.41 | 0.41 | 0.89 |
| Lower 48 States | 5.10 | 6.33 | 6.98 | 9.14 | 5.57 | 5.92 | 9.27 | 5.49 | 5.72 | 9.35 |
| Net imports | 8.89 | 7.55 | 6.82 | 4.57 | 7.89 | 7.36 | 3.74 | 8.12 | 7.57 | 3.09 |
| Gross imports | 8.94 | 7.55 | 6.82 | 4.57 | 7.89 | 7.36 | 3.74 | 8.12 | 7.57 | 3.09 |
| Exports | 0.05 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| Other crude oil supply[3] | 0.26 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| **Total crude oil supply** | **14.81** | **14.37** | **14.29** | **14.24** | **13.85** | **13.66** | **13.70** | **14.02** | **13.70** | **13.33** |
| **Other petroleum supply** | **3.02** | **3.90** | **4.04** | **4.40** | **3.65** | **3.82** | **4.30** | **3.17** | **3.29** | **3.96** |
| Natural gas plant liquids | 2.22 | 2.77 | 3.13 | 4.13 | 2.46 | 2.90 | 4.69 | 2.40 | 2.92 | 5.02 |
| Net product imports | -0.30 | 0.06 | -0.13 | -0.68 | 0.15 | -0.08 | -1.22 | -0.32 | -0.67 | -1.82 |
| Gross refined product imports[4] | 1.15 | 1.46 | 1.47 | 1.42 | 1.71 | 1.53 | 1.36 | 1.67 | 1.42 | 1.30 |
| Unfinished oil imports | 0.69 | 0.56 | 0.56 | 0.56 | 0.51 | 0.51 | 0.51 | 0.45 | 0.45 | 0.45 |
| Blending component imports | 0.72 | 0.63 | 0.63 | 0.63 | 0.54 | 0.54 | 0.45 | 0.42 | 0.40 | 0.37 |
| Exports | 2.86 | 2.60 | 2.79 | 3.30 | 2.62 | 2.67 | 3.53 | 2.86 | 2.94 | 3.94 |
| Refinery processing gain[5] | 1.08 | 1.08 | 1.04 | 0.95 | 1.04 | 1.00 | 0.82 | 1.08 | 1.03 | 0.77 |
| Product stock withdrawal | 0.03 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| **Other non-petroleum supply** | **1.09** | **1.47** | **1.51** | **1.50** | **1.48** | **1.58** | **1.60** | **1.79** | **1.97** | **2.25** |
| Supply from renewable sources | 0.90 | 1.18 | 1.18 | 1.19 | 1.13 | 1.14 | 1.16 | 1.40 | 1.43 | 1.38 |
| Ethanol | 0.84 | 1.07 | 1.08 | 1.09 | 0.99 | 0.99 | 1.02 | 0.95 | 0.97 | 0.99 |
| Domestic production | 0.91 | 1.00 | 1.01 | 1.02 | 0.95 | 0.95 | 0.98 | 0.86 | 0.89 | 0.93 |
| Net imports | -0.07 | 0.07 | 0.07 | 0.07 | 0.04 | 0.04 | 0.04 | 0.10 | 0.08 | 0.06 |
| Biodiesel | 0.06 | 0.08 | 0.08 | 0.08 | 0.08 | 0.08 | 0.08 | 0.08 | 0.08 | 0.08 |
| Domestic production | 0.06 | 0.07 | 0.07 | 0.07 | 0.07 | 0.07 | 0.07 | 0.07 | 0.07 | 0.07 |
| Net imports | 0.00 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 |
| Other biomass-derived liquids[6] | 0.00 | 0.02 | 0.02 | 0.02 | 0.06 | 0.06 | 0.06 | 0.37 | 0.38 | 0.32 |
| Liquids from gas | 0.00 | 0.04 | 0.08 | 0.08 | 0.05 | 0.13 | 0.22 | 0.07 | 0.20 | 0.62 |
| Liquids from coal | 0.00 | 0.00 | 0.00 | 0.00 | 0.02 | 0.04 | 0.00 | 0.03 | 0.06 | 0.04 |
| Other[7] | 0.18 | 0.26 | 0.25 | 0.23 | 0.28 | 0.28 | 0.22 | 0.29 | 0.28 | 0.20 |
| **Total primary supply[8]** | **18.92** | **19.74** | **19.84** | **20.15** | **18.98** | **19.06** | **19.59** | **18.99** | **18.96** | **19.55** |
| Net import share of product supplied (percent) | 45.0 | 39.0 | 34.1 | 19.7 | 42.7 | 38.5 | 13.1 | 41.7 | 36.9 | 6.9 |
| Net expenditures for imports of crude oil and petroleum products (billion 2011 dollars) | 362.66 | 293.15 | 259.66 | 163.99 | 370.21 | 342.67 | 158.79 | 471.38 | 433.65 | 159.39 |
| **Lower 48 end of year reserves[2] (billion barrels)** | **21.36** | **23.07** | **24.63** | **29.69** | **24.11** | **24.92** | **31.36** | **26.03** | **26.72** | **32.75** |

# Table D8. Liquid fuels supply and disposition, oil and gas resource cases (continued)

(million barrels per day, unless otherwise noted)

| Supply, disposition, and prices | 2011 | 2020 Low Oil and Gas Resource | 2020 Reference | 2020 High Oil and Gas Resource | 2030 Low Oil and Gas Resource | 2030 Reference | 2030 High Oil and Gas Resource | 2040 Low Oil and Gas Resource | 2040 Reference | 2040 High Oil and Gas Resource |
|---|---|---|---|---|---|---|---|---|---|---|
| **Refined petroleum product prices to the transportation sector (2011 dollars per gallon)** | | | | | | | | | | |
| Propane | 2.22 | 2.18 | 2.07 | 1.73 | 2.34 | 2.26 | 1.94 | 2.50 | 2.44 | 2.24 |
| Ethanol (E85)[9] | 2.42 | 2.89 | 2.83 | 2.73 | 2.61 | 2.57 | 2.35 | 3.14 | 2.92 | 2.74 |
| Ethanol wholesale price | 2.54 | 3.05 | 3.00 | 2.95 | 2.36 | 2.28 | 2.27 | 2.61 | 2.48 | 2.27 |
| Motor gasoline[10] | 3.45 | 3.38 | 3.32 | 3.16 | 3.72 | 3.67 | 3.39 | 4.39 | 4.32 | 3.93 |
| Jet fuel[11] | 3.04 | 2.97 | 2.90 | 2.70 | 3.59 | 3.51 | 3.16 | 4.34 | 4.19 | 3.71 |
| Distillate fuel oil[12] | 3.58 | 3.71 | 3.65 | 3.45 | 4.28 | 4.22 | 3.94 | 5.05 | 4.94 | 4.47 |
| Residual fuel oil | 2.67 | 2.29 | 2.23 | 2.07 | 2.78 | 2.75 | 2.46 | 3.44 | 3.36 | 2.98 |
| Residual fuel oil (2011 dollars per barrel) | 112.11 | 96.00 | 93.74 | 87.03 | 116.81 | 115.30 | 103.28 | 144.39 | 141.16 | 125.08 |

[1]Weighted average price delivered to U.S. refiners.
[2]Includes lease condensate.
[3]Strategic petroleum reserve stock additions plus unaccounted for crude oil and crude stock withdrawals minus crude product supplied.
[4]Includes other hydrocarbons and alcohol.
[5]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.
[6]Includes pyrolysis oils, biomass-derived Fischer-Tropsch liquids, and renewable feedstocks used for the on-site production of diesel and gasoline.
[7]Includes domestic sources of other blending components, other hydrocarbons, and ethers.
[8]Total crude supply plus other petroleum supply plus other non-petroleum supply.
[9]E85 refers to a blend of 85 pecent 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]Sales weighted-average price for all grades. Includes Federal, State, and local taxes.
[11]Includes only kerosene-type.
[12]Diesel fuel for on-road use. Includes Federal and State taxes while excluding county and local taxes.
Note: Totals may not equal sum of components due to independent rounding. Data for 2011 are model results and may differ slightly from official EIA data reports.
**Sources:** 2011 product supplied data and imported crude oil price based on: U.S. Energy Information Administration (EIA), *Annual Energy Review 2011*, DOE/EIA-0384(2011) (Washington, DC, September 2012). 2011 crude oil spot prices: Thomson Reuters. 2011 transportation sector prices based on: EIA, Form EIA-782A, “Refiners’/Gas Plant Operators’ Monthly Petroleum Product Sales Report”. 2011 E85 prices derived from monthly prices in the Clean Cities Alternative Fuel Price Report. 2011 wholesale ethanol prices derived from Bloomberg U.S. average rack price. Other 2011 data: EIA, *Petroleum Supply Annual 2011*, DOE/EIA-0340(2011)/1 (Washington, DC, August 2012). **Projections:** EIA, AEO2013 National Energy Modeling System runs LOWRESOURCE.D012813A, REF2013.D102312A, and HIGHRESOURCE.D021413A.

## Table D9. Key transportation results, oil and gas resource cases

| Consumption and indicators | 2011 | 2020 | | | 2030 | | | 2040 | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | | Low Oil and Gas Resource | Reference | High Oil and Gas Resource | Low Oil and Gas Resource | Reference | High Oil and Gas Resource | Low Oil and Gas Resource | Reference | High Oil and Gas Resource |
| **Level of travel** | | | | | | | | | | |
| (billion vehicle miles traveled) | | | | | | | | | | |
| Light-duty vehicles less than 8,501 pounds | 2,629 | 2,860 | 2,870 | 2,901 | 3,312 | 3,323 | 3,372 | 3,711 | 3,719 | 3,775 |
| Commercial light trucks[1] | 65 | 80 | 80 | 81 | 94 | 94 | 96 | 109 | 110 | 112 |
| Freight trucks greater than 10,000 pounds | 240 | 321 | 323 | 332 | 369 | 371 | 385 | 437 | 438 | 454 |
| (billion seat miles available) | | | | | | | | | | |
| Air | 982 | 1,081 | 1,082 | 1,082 | 1,177 | 1,177 | 1,177 | 1,274 | 1,274 | 1,274 |
| (billion ton miles traveled) | | | | | | | | | | |
| Rail | 1,557 | 1,755 | 1,719 | 1,622 | 1,909 | 1,910 | 1,772 | 2,000 | 2,017 | 1,947 |
| Domestic shipping | 514 | 594 | 612 | 703 | 567 | 578 | 737 | 581 | 591 | 773 |
| **Energy efficiency indicators** | | | | | | | | | | |
| (miles per gallon) | | | | | | | | | | |
| Tested new light-duty vehicle[2] | 31.5 | 38.0 | 37.9 | 37.7 | 48.2 | 48.1 | 47.7 | 49.1 | 49.0 | 48.5 |
| New car[2] | 36.4 | 44.4 | 44.4 | 44.3 | 55.6 | 55.6 | 55.5 | 56.1 | 56.1 | 55.9 |
| New light truck[2] | 27.3 | 32.1 | 32.0 | 31.9 | 40.4 | 40.3 | 40.1 | 40.5 | 40.4 | 40.1 |
| On-road new light-duty vehicle[3] | 25.5 | 30.7 | 30.6 | 30.4 | 39.0 | 38.9 | 38.6 | 39.7 | 39.7 | 39.3 |
| New car[3] | 29.8 | 36.3 | 36.3 | 36.2 | 45.4 | 45.4 | 45.3 | 45.8 | 45.8 | 45.7 |
| New light truck[3] | 21.8 | 25.7 | 25.6 | 25.5 | 32.4 | 32.3 | 32.1 | 32.4 | 32.3 | 32.1 |
| Light-duty stock[4] | 20.6 | 24.1 | 24.1 | 24.0 | 31.4 | 31.3 | 31.2 | 36.2 | 36.1 | 35.8 |
| New commercial light truck[1] | 18.1 | 20.0 | 20.0 | 19.9 | 24.2 | 24.1 | 24.0 | 24.2 | 24.2 | 24.0 |
| Stock commercial light truck[1] | 14.9 | 17.9 | 17.9 | 17.9 | 22.2 | 22.2 | 22.1 | 24.1 | 24.1 | 23.9 |
| Freight truck | 6.7 | 7.3 | 7.3 | 7.3 | 8.0 | 8.0 | 8.0 | 8.2 | 8.2 | 8.1 |
| (seat miles per gallon) | | | | | | | | | | |
| Aircraft | 62.3 | 63.9 | 63.9 | 63.9 | 67.0 | 67.0 | 67.0 | 71.5 | 71.5 | 71.5 |
| (ton miles per thousand Btu) | | | | | | | | | | |
| Rail | 3.4 | 3.5 | 3.5 | 3.5 | 3.5 | 3.5 | 3.5 | 3.5 | 3.5 | 3.5 |
| Domestic shipping | 2.4 | 2.5 | 2.5 | 2.5 | 2.5 | 2.5 | 2.5 | 2.6 | 2.6 | 2.6 |
| **Energy use by mode (quadrillion Btu)** | | | | | | | | | | |
| Light-duty vehicles | 15.56 | 14.29 | 14.35 | 14.53 | 12.71 | 12.77 | 13.02 | 12.38 | 12.43 | 12.72 |
| Commercial light trucks[1] | 0.54 | 0.56 | 0.56 | 0.57 | 0.53 | 0.53 | 0.54 | 0.57 | 0.57 | 0.58 |
| Bus transportation | 0.25 | 0.27 | 0.27 | 0.27 | 0.29 | 0.29 | 0.29 | 0.32 | 0.32 | 0.32 |
| Freight trucks | 4.95 | 6.02 | 6.07 | 6.24 | 6.34 | 6.39 | 6.64 | 7.27 | 7.31 | 7.62 |
| Rail, passenger | 0.05 | 0.05 | 0.05 | 0.05 | 0.06 | 0.06 | 0.06 | 0.06 | 0.06 | 0.06 |
| Rail, freight | 0.45 | 0.51 | 0.49 | 0.47 | 0.54 | 0.54 | 0.50 | 0.56 | 0.57 | 0.55 |
| Shipping, domestic | 0.21 | 0.24 | 0.25 | 0.29 | 0.23 | 0.23 | 0.30 | 0.23 | 0.23 | 0.30 |
| Shipping, international | 0.80 | 0.81 | 0.81 | 0.81 | 0.82 | 0.82 | 0.82 | 0.84 | 0.84 | 0.84 |
| Recreational boats | 0.24 | 0.26 | 0.26 | 0.26 | 0.27 | 0.28 | 0.28 | 0.29 | 0.29 | 0.30 |
| Air | 2.46 | 2.65 | 2.65 | 2.66 | 2.78 | 2.78 | 2.79 | 2.85 | 2.86 | 2.86 |
| Military use | 0.74 | 0.63 | 0.63 | 0.63 | 0.68 | 0.68 | 0.68 | 0.77 | 0.77 | 0.77 |
| Lubricants | 0.13 | 0.12 | 0.12 | 0.12 | 0.12 | 0.12 | 0.13 | 0.13 | 0.13 | 0.13 |
| Pipeline fuel | 0.70 | 0.67 | 0.71 | 0.79 | 0.69 | 0.74 | 0.86 | 0.68 | 0.78 | 0.99 |
| **Total** | **27.09** | **27.08** | **27.24** | **27.69** | **26.07** | **26.24** | **26.92** | **26.94** | **27.14** | **28.03** |

## Table D9. Key transportation results, oil and gas resource cases (continued)

| Consumption and indicators | 2011 | 2020 | | | 2030 | | | 2040 | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | | Low Oil and Gas Resource | Reference | High Oil and Gas Resource | Low Oil and Gas Resource | Reference | High Oil and Gas Resource | Low Oil and Gas Resource | Reference | High Oil and Gas Resource |
| **Energy use by fuel (quadrillion Btu)** | | | | | | | | | | |
| Propane | 0.06 | 0.06 | 0.06 | 0.07 | 0.07 | 0.07 | 0.08 | 0.08 | 0.08 | 0.09 |
| E85[5] | 0.05 | 0.08 | 0.08 | 0.08 | 0.16 | 0.16 | 0.17 | 0.15 | 0.17 | 0.16 |
| Motor gasoline[6] | 16.31 | 14.82 | 14.88 | 15.07 | 13.00 | 13.06 | 13.32 | 12.61 | 12.64 | 12.98 |
| Jet fuel[7] | 3.01 | 3.11 | 3.11 | 3.12 | 3.28 | 3.28 | 3.28 | 3.42 | 3.42 | 3.42 |
| Distillate fuel oil[8] | 5.91 | 7.25 | 7.28 | 7.44 | 7.64 | 7.61 | 7.86 | 8.12 | 7.90 | 8.22 |
| Residual fuel oil | 0.82 | 0.84 | 0.84 | 0.85 | 0.85 | 0.86 | 0.87 | 0.87 | 0.87 | 0.89 |
| Other petroleum[9] | 0.17 | 0.15 | 0.15 | 0.15 | 0.16 | 0.16 | 0.16 | 0.16 | 0.16 | 0.16 |
| Liquid fuels and other petroleum | 26.32 | 26.31 | 26.42 | 26.79 | 25.16 | 25.20 | 25.74 | 25.41 | 25.24 | 25.92 |
| Pipeline fuel natural gas | 0.70 | 0.67 | 0.71 | 0.79 | 0.69 | 0.74 | 0.86 | 0.68 | 0.78 | 0.99 |
| Compressed/liquefied natural gas | 0.04 | 0.07 | 0.08 | 0.08 | 0.18 | 0.26 | 0.27 | 0.78 | 1.05 | 1.06 |
| Liquid hydrogen | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| Electricity | 0.02 | 0.03 | 0.03 | 0.03 | 0.05 | 0.04 | 0.04 | 0.07 | 0.07 | 0.06 |
| **Delivered energy** | **27.09** | **27.08** | **27.24** | **27.69** | **26.07** | **26.25** | **26.92** | **26.94** | **27.14** | **28.03** |
| Electricity related losses | 0.05 | 0.06 | 0.06 | 0.06 | 0.09 | 0.09 | 0.08 | 0.13 | 0.13 | 0.12 |
| **Total** | **27.13** | **27.15** | **27.30** | **27.74** | **26.16** | **26.33** | **27.01** | **27.07** | **27.27** | **28.15** |

[1]Commercial trucks 8,501 to 10,000 pounds gross vehicle weight rating.
[2]Environmental Protection Agency rated miles per gallon.
[3]Tested new vehicle efficiency revised for on-road performance.
[4]Combined “on-the-road” estimate for all cars and light trucks.
[5]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.
[6]Includes ethanol (blends of 15 percent or less) and ethers blended into gasoline.
[7]Includes only kerosene type.
[8]Diesel fuel for on- and off- road use.
[9]Includes aviation gasoline and lubricants.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Data for 2011 are model results and may differ slightly from official EIA data reports.
**Source:** 2011 consumption based on: U.S. Energy Information Administration (EIA), *Annual Energy Review 2011*, DOE/EIA-0384(2011) (Washington, DC, September 2012). Other 2011 data: Federal Highway Administration, *Highway Statistics 2010* (Washington, DC, February 2012); Oak Ridge National Laboratory, *Transportation Energy Data Book: Edition 31* (Oak Ridge, TN, July 2012); National Highway Traffic and Safety Administration, *Summary of Fuel Economy Performance* (Washington, DC, October 28, 2010); U.S. Department of Commerce, Bureau of the Census, “Vehicle Inventory and Use Survey”, EC02TV (Washington, DC, December 2004); EIA, Alternatives to Traditional Transportation Fuels 2009 (Part II – User and Fuel Data), April 2011; EIA, *State Energy Data Report 2010*, DOE/EIA-0214(2010) (Washington, DC, June 2012); U.S. Department of Transportation, Research and Special Programs Administration, *Air Carrier Statistics Monthly, December 2010-2009* (Washington, DC, December 2010); and United States Department of Defense, Defense Fuel Supply Center, Factbook (January, 2010). **Projections:** EIA, AEO2013 National Energy Modeling System runs LOWRESOURCE.D012813A, REF2013.D102312A, and HIGHRESOURCE.D021413A.

## Table D10. Natural gas supply and disposition, oil import cases
(trillion cubic feet per year, unless otherwise noted)

| Supply, disposition, and prices | 2011 | 2030 | | | | 2040 | | | |
|---|---|---|---|---|---|---|---|---|---|
| | | High Net Imports | Reference | High Oil and Gas Resource | Low/No Net Imports | High Net Imports | Reference | High Oil and Gas Resource | Low/No Net Imports |
| **Henry Hub spot price** | | | | | | | | | |
| (2011 dollars per million Btu) | 3.98 | 7.12 | 5.40 | 3.26 | 3.34 | 10.69 | 7.83 | 4.32 | 4.36 |
| (2011 dollars per thousand cubic feet) | 4.07 | 7.28 | 5.52 | 3.33 | 3.41 | 10.93 | 8.00 | 4.42 | 4.45 |
| **Dry gas production[1]** | **23.00** | **25.87** | **29.79** | **36.89** | **37.23** | **27.29** | **33.14** | **44.91** | **45.12** |
| Lower 48 onshore | 20.54 | 21.95 | 26.26 | 33.30 | 33.65 | 22.69 | 29.12 | 40.74 | 41.03 |
| Associated-dissolved[2] | 1.54 | 1.24 | 1.43 | 3.05 | 3.02 | 0.93 | 1.09 | 2.70 | 2.67 |
| Non-associated | 19.00 | 20.71 | 24.83 | 30.25 | 30.62 | 21.76 | 28.03 | 38.04 | 38.36 |
| Tight gas | 5.86 | 5.79 | 6.67 | 8.86 | 8.96 | 5.97 | 7.34 | 10.72 | 10.78 |
| Shale gas | 7.85 | 10.45 | 14.17 | 17.56 | 17.84 | 11.32 | 16.70 | 23.93 | 24.18 |
| Coalbed methane | 1.71 | 2.16 | 1.69 | 1.51 | 1.52 | 2.59 | 2.11 | 1.53 | 1.53 |
| Other | 3.58 | 2.30 | 2.31 | 2.32 | 2.31 | 1.88 | 1.87 | 1.86 | 1.87 |
| Lower 48 offshore | 2.11 | 2.73 | 2.34 | 2.37 | 2.36 | 3.41 | 2.85 | 2.92 | 2.85 |
| Associated-dissolved[2] | 0.54 | 0.72 | 0.60 | 0.65 | 0.65 | 0.90 | 0.74 | 0.81 | 0.79 |
| Non-associated | 1.58 | 2.01 | 1.73 | 1.72 | 1.71 | 2.52 | 2.11 | 2.12 | 2.06 |
| Alaska | 0.35 | 1.19 | 1.19 | 1.22 | 1.22 | 1.18 | 1.18 | 1.25 | 1.24 |
| Supplemental natural gas[3] | 0.06 | 0.06 | 0.06 | 0.06 | 0.06 | 0.06 | 0.06 | 0.06 | 0.06 |
| **Net imports** | **1.95** | **-0.78** | **-2.10** | **-3.63** | **-3.60** | **-2.24** | **-3.55** | **-6.70** | **-6.68** |
| Pipeline[4] | 1.67 | 0.08 | -0.67 | -1.57 | -1.53 | -1.10 | -2.09 | -2.84 | -2.82 |
| Liquefied natural gas | 0.28 | -0.86 | -1.43 | -2.06 | -2.06 | -1.14 | -1.46 | -3.86 | -3.86 |
| **Total supply** | **25.01** | **25.16** | **27.75** | **33.33** | **33.70** | **25.11** | **29.65** | **38.27** | **38.50** |
| **Consumption by sector** | | | | | | | | | |
| Residential | 4.72 | 4.25 | 4.36 | 4.52 | 4.51 | 4.00 | 4.14 | 4.31 | 4.34 |
| Commercial | 3.16 | 3.25 | 3.42 | 3.71 | 3.69 | 3.37 | 3.60 | 3.97 | 3.97 |
| Industrial[5] | 6.77 | 7.66 | 7.79 | 8.04 | 7.94 | 7.74 | 7.90 | 8.14 | 8.16 |
| Natural-gas-to-liquids heat and power[6] | 0.00 | 0.09 | 0.21 | 0.36 | 0.36 | 0.11 | 0.33 | 1.01 | 0.93 |
| Natural gas to liquids production[7] | 0.00 | 0.10 | 0.22 | 0.39 | 0.39 | 0.12 | 0.35 | 1.10 | 1.01 |
| Electric power[8] | 7.60 | 7.11 | 8.89 | 12.89 | 12.83 | 6.02 | 9.50 | 14.78 | 14.78 |
| Transportation[9] | 0.04 | 0.36 | 0.26 | 0.27 | 0.70 | 1.29 | 1.04 | 1.04 | 1.26 |
| Pipeline fuel | 0.68 | 0.68 | 0.73 | 0.85 | 0.85 | 0.67 | 0.76 | 0.97 | 0.97 |
| Lease and plant fuel[10] | 1.39 | 1.48 | 1.70 | 2.12 | 2.18 | 1.66 | 1.93 | 2.79 | 2.83 |
| **Total** | **24.37** | **24.98** | **27.57** | **33.14** | **33.46** | **25.00** | **29.54** | **38.11** | **38.26** |
| Discrepancy[11] | 0.64 | 0.18 | 0.18 | 0.19 | 0.24 | 0.11 | 0.12 | 0.16 | 0.24 |
| **Lower 48 end of year dry reserves[1]** | **298.96** | **321.40** | **350.65** | **435.34** | **435.38** | **329.61** | **359.97** | **450.88** | **450.65** |

[1]Marketed production (wet) minus extraction losses.
[2]Gas which occurs in crude oil reservoirs either as free gas (associated) or as gas in solution with crude oil (dissolved).
[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, as well as gas from Canada and Mexico.
[5]Includes energy for combined heat and power plants that have a non-regulatory status, and small on-site generating systems.
[6]Includes any natural gas used in the process of converting natural gas to liquid fuel that is not actually converted.
[7]Includes any natural gas converted into liquid fuel.
[8]Includes consumption of energy by electricity-only and combined heat and power plants that have a regulatory status.
[9]Natural gas used as a vehicle fuel.
[10]Represents natural gas used in well, field, and lease operations, in natural gas processing plant machinery, and for liquefaction in export facilities.
[11]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, 2011 values include net storage injections.
Note: Totals may not equal sum of components due to independent rounding. Data for 2011 are model results and may differ slightly from official EIA data reports.
**Sources:** 2011 supply values; lease, plant, and pipeline fuel consumption: U.S. Energy Information Administration (EIA), *Natural Gas Monthly*, DOE/EIA-0130(2012/07) (Washington, DC, July 2012). Other 2011 consumption based on: EIA, *Annual Energy Review 2011*, DOE/EIA-0384(2011) (Washington, DC, September 2012). 2011 natural gas price at Henry Hub based on daily spot prices published in Natural Gas Intelligence. **Projections:** EIA, AEO2013 National Energy Modeling System runs HIGHIMPORT.D012813A, REF2013.D102312A, HIGHRESOURCE.D021413A, and LOWIMPORT.D021113B.

**Table D11. Liquid fuels supply and disposition, oil import cases**
(million barrels per day, unless otherwise noted)

| Supply, disposition, and prices | 2011 | 2030 | | | | 2040 | | | |
|---|---|---|---|---|---|---|---|---|---|
| | | High Net Imports | Reference | High Oil and Gas Resource | Low/No Net Imports | High Net Imports | Reference | High Oil and Gas Resource | Low/No Net Imports |
| **Crude oil prices** | | | | | | | | | |
| **(2011 dollars per barrel)** | | | | | | | | | |
| Brent spot | 111.26 | 135.83 | 130.47 | 117.09 | 111.04 | 170.69 | 162.68 | 143.97 | 133.95 |
| West Texas Intermediate spot | 94.86 | 133.75 | 128.47 | 115.30 | 109.33 | 168.59 | 160.68 | 142.20 | 132.30 |
| Imported crude oil[1] | 102.65 | 129.57 | 125.64 | 112.93 | 107.01 | 161.59 | 154.96 | 136.97 | 127.64 |
| **Crude oil supply** | | | | | | | | | |
| Domestic production[2] | 5.67 | 6.04 | 6.30 | 9.96 | 9.92 | 5.90 | 6.13 | 10.24 | 10.15 |
| Alaska | 0.57 | 0.44 | 0.38 | 0.69 | 0.69 | 0.38 | 0.41 | 0.89 | 0.91 |
| Lower 48 States | 5.10 | 5.60 | 5.92 | 9.27 | 9.23 | 5.51 | 5.72 | 9.35 | 9.25 |
| Net imports | 8.89 | 8.80 | 7.36 | 3.74 | 3.15 | 9.28 | 7.57 | 3.09 | 3.29 |
| Gross imports | 8.94 | 8.80 | 7.36 | 3.74 | 3.15 | 9.28 | 7.57 | 3.09 | 3.29 |
| Exports | 0.05 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| Other crude oil supply[3] | 0.26 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| **Total crude oil supply** | **14.81** | **14.84** | **13.66** | **13.70** | **13.06** | **15.18** | **13.70** | **13.33** | **13.45** |
| **Other petroleum supply** | **3.02** | **3.74** | **3.82** | **4.30** | **2.99** | **3.36** | **3.29** | **3.96** | **1.11** |
| Natural gas plant liquids | 2.22 | 2.47 | 2.90 | 4.69 | 4.70 | 2.43 | 2.92 | 5.02 | 5.00 |
| Net product imports | -0.30 | 0.11 | -0.08 | -1.22 | -2.41 | -0.32 | -0.67 | -1.82 | -4.64 |
| Gross refined product imports[4] | 1.15 | 1.71 | 1.53 | 1.36 | 1.38 | 1.69 | 1.42 | 1.30 | 1.33 |
| Unfinished oil imports | 0.69 | 0.51 | 0.51 | 0.51 | 0.51 | 0.45 | 0.45 | 0.45 | 0.45 |
| Blending component imports | 0.72 | 0.56 | 0.54 | 0.45 | 0.45 | 0.48 | 0.40 | 0.37 | 0.37 |
| Exports | 2.86 | 2.67 | 2.67 | 3.53 | 4.75 | 2.94 | 2.94 | 3.94 | 6.79 |
| Refinery processing gain[5] | 1.08 | 1.16 | 1.00 | 0.82 | 0.70 | 1.25 | 1.03 | 0.77 | 0.75 |
| Product stock withdrawal | 0.03 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| **Other non-petroleum supply** | **1.09** | **1.62** | **1.58** | **1.60** | **1.60** | **2.01** | **1.97** | **2.25** | **2.25** |
| Supply from renewable sources | 0.90 | 1.23 | 1.14 | 1.16 | 1.17 | 1.57 | 1.43 | 1.38 | 1.44 |
| Ethanol | 0.84 | 1.09 | 0.99 | 1.02 | 1.03 | 1.13 | 0.97 | 0.99 | 1.01 |
| Domestic production | 0.91 | 1.01 | 0.95 | 0.98 | 0.97 | 1.01 | 0.89 | 0.93 | 0.95 |
| Net imports | -0.07 | 0.08 | 0.04 | 0.04 | 0.06 | 0.12 | 0.08 | 0.06 | 0.06 |
| Biodiesel | 0.06 | 0.08 | 0.08 | 0.08 | 0.07 | 0.08 | 0.08 | 0.08 | 0.07 |
| Domestic production | 0.06 | 0.07 | 0.07 | 0.07 | 0.06 | 0.07 | 0.07 | 0.07 | 0.06 |
| Net imports | 0.00 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 |
| Other biomass-derived liquids[6] | 0.00 | 0.06 | 0.06 | 0.06 | 0.07 | 0.36 | 0.38 | 0.32 | 0.36 |
| Liquids from gas | 0.00 | 0.05 | 0.13 | 0.22 | 0.22 | 0.07 | 0.20 | 0.62 | 0.57 |
| Liquids from coal | 0.00 | 0.04 | 0.04 | 0.00 | 0.00 | 0.06 | 0.06 | 0.04 | 0.04 |
| Other[7] | 0.18 | 0.30 | 0.28 | 0.22 | 0.21 | 0.31 | 0.28 | 0.20 | 0.21 |
| **Total primary supply[8]** | **18.92** | **20.20** | **19.06** | **19.59** | **17.65** | **20.55** | **18.96** | **19.55** | **16.81** |
| Net import share of product supplied (percent) | 45.0 | 44.6 | 38.5 | 13.1 | 4.6 | 44.3 | 36.9 | 6.9 | -7.6 |
| Net expenditures for imports of crude oil and petroleum products (billion 2011 dollars) | 362.66 | 421.73 | 342.67 | 158.79 | 127.58 | 553.11 | 433.65 | 159.39 | 158.09 |
| **Lower 48 end of year reserves[2] (billion barrels)** | **21.36** | **24.19** | **24.92** | **31.36** | **31.32** | **26.06** | **26.72** | **32.75** | **32.55** |

# Table D11. Liquid fuels supply and disposition, oil import cases (continued)
(million barrels per day, unless otherwise noted)

| Supply, disposition, and prices | 2011 | 2030 | | | | 2040 | | | |
|---|---|---|---|---|---|---|---|---|---|
| | | High Net Imports | Reference | High Oil and Gas Resource | Low/No Net Imports | High Net Imports | Reference | High Oil and Gas Resource | Low/No Net Imports |
| **Refined petroleum product prices to the transportation sector (2011 dollars per gallon)** | | | | | | | | | |
| Propane | 2.22 | 2.35 | 2.26 | 1.94 | 1.94 | 2.52 | 2.44 | 2.24 | 2.18 |
| Ethanol (E85)[9] | 2.42 | 2.95 | 2.57 | 2.35 | 2.44 | 3.81 | 2.92 | 2.74 | 2.72 |
| Ethanol wholesale price | 2.54 | 2.67 | 2.28 | 2.27 | 2.56 | 3.13 | 2.48 | 2.27 | 2.38 |
| Motor gasoline[10] | 3.45 | 3.85 | 3.67 | 3.39 | 3.32 | 4.64 | 4.32 | 3.93 | 3.68 |
| Jet fuel[11] | 3.04 | 3.68 | 3.51 | 3.16 | 3.04 | 4.50 | 4.19 | 3.71 | 3.53 |
| Distillate fuel oil[12] | 3.58 | 4.36 | 4.22 | 3.94 | 3.87 | 5.16 | 4.94 | 4.47 | 4.27 |
| Residual fuel oil | 2.67 | 2.83 | 2.75 | 2.46 | 2.35 | 3.55 | 3.36 | 2.98 | 2.80 |
| Residual fuel oil (2011 dollars per barrel) | 112.11 | 118.76 | 115.30 | 103.28 | 98.84 | 149.01 | 141.16 | 125.08 | 117.71 |

[1]Weighted average price delivered to U.S. refiners.
[2]Includes lease condensate.
[3]Strategic petroleum reserve stock additions plus unaccounted for crude oil and crude stock withdrawals minus crude product supplied.
[4]Includes other hydrocarbons and alcohol.
[5]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.
[6]Includes pyrolysis oils, biomass-derived Fischer-Tropsch liquids, and renewable feedstocks used for the on-site production of diesel and gasoline.
[7]Includes domestic sources of other blending components, other hydrocarbons, and ethers.
[8]Total crude supply plus other petroleum supply plus other non-petroleum supply.
[9]E85 refers to a blend of 85 pecent 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]Sales weighted-average price for all grades. Includes Federal, State, and local taxes.
[11]Includes only kerosene-type.
[12]Diesel fuel for on-road use. Includes Federal and State taxes while excluding county and local taxes.
Note: Totals may not equal sum of components due to independent rounding. Data for 2011 are model results and may differ slightly from official EIA data reports.
**Sources:** 2011 product supplied data and imported crude oil price based on: U.S. Energy Information Administration (EIA), *Annual Energy Review 2011*, DOE/EIA-0384(2011) (Washington, DC, September 2012). 2011 crude oil spot prices: Thomson Reuters. 2011 transportation sector prices based on: EIA, Form EIA-782A, “Refiners’/Gas Plant Operators’ Monthly Petroleum Product Sales Report”. 2011 E85 prices derived from monthly prices in the Clean Cities Alternative Fuel Price Report. 2011 wholesale ethanol prices derived from Bloomberg U.S. average rack price. Other 2011 data: EIA, Petroleum Supply Annual 2011, DOE/EIA-0340(2011)/1 (Washington, DC, August 2012). **Projections:** EIA, AEO2013 National Energy Modeling System runs HIGHIMPORT.D012813A, REF2013.D102312A, HIGHRESOURCE.D021413A, and LOWIMPORT.D021113B.

## Table D12. Key transportation results, oil import cases

| Consumption and indicators | 2011 | 2030 | | | | 2040 | | | |
|---|---|---|---|---|---|---|---|---|---|
| | | High Net Imports | Reference | High Oil and Gas Resource | Low/No Net Imports | High Net Imports | Reference | High Oil and Gas Resource | Low/No Net Imports |
| **Level of travel** | | | | | | | | | |
| (billion vehicle miles traveled) | | | | | | | | | |
| Light-duty vehicles less than 8,501 pounds | 2,629 | 3,257 | 3,323 | 3,372 | 2,753 | 3,607 | 3,719 | 3,775 | 2,761 |
| Commercial light trucks[1] | 65 | 93 | 94 | 96 | 90 | 109 | 110 | 112 | 103 |
| Freight trucks greater than 10,000 pounds | 240 | 369 | 371 | 385 | 385 | 437 | 438 | 454 | 455 |
| (billion seat miles available) | | | | | | | | | |
| Air | 982 | 1,177 | 1,177 | 1,177 | 1,177 | 1,274 | 1,274 | 1,274 | 1,274 |
| (billion ton miles traveled) | | | | | | | | | |
| Rail | 1,557 | 1,910 | 1,910 | 1,772 | 1,784 | 1,997 | 2,017 | 1,947 | 1,966 |
| Domestic shipping | 514 | 570 | 578 | 737 | 735 | 582 | 591 | 773 | 769 |
| **Energy efficiency indicators** | | | | | | | | | |
| (miles per gallon) | | | | | | | | | |
| Tested new light-duty vehicle[2] | 31.5 | 38.8 | 48.1 | 47.7 | 51.6 | 39.8 | 49.0 | 48.5 | 57.6 |
| New car[2] | 36.4 | 44.4 | 55.6 | 55.5 | 60.5 | 45.5 | 56.1 | 55.9 | 66.4 |
| New light truck[2] | 27.3 | 32.7 | 40.3 | 40.1 | 43.5 | 33.2 | 40.4 | 40.1 | 48.1 |
| On-road new light-duty vehicle[3] | 25.5 | 31.4 | 38.9 | 38.6 | 41.7 | 32.2 | 39.7 | 39.3 | 46.6 |
| New car[3] | 29.8 | 36.3 | 45.4 | 45.3 | 49.4 | 37.1 | 45.8 | 45.7 | 54.2 |
| New light truck[3] | 21.8 | 26.2 | 32.3 | 32.1 | 34.8 | 26.6 | 32.3 | 32.1 | 38.5 |
| Light-duty stock[4] | 20.6 | 27.5 | 31.3 | 31.2 | 31.7 | 29.8 | 36.1 | 35.8 | 39.1 |
| New commercial light truck[1] | 18.1 | 20.5 | 24.1 | 24.0 | 24.9 | 20.7 | 24.2 | 24.0 | 26.9 |
| Stock commercial light truck[1] | 14.9 | 19.8 | 22.2 | 22.1 | 22.4 | 20.6 | 24.1 | 23.9 | 25.7 |
| Freight truck | 6.7 | 7.5 | 8.0 | 8.0 | 8.4 | 7.6 | 8.2 | 8.1 | 8.7 |
| (seat miles per gallon) | | | | | | | | | |
| Aircraft | 62.3 | 66.0 | 67.0 | 67.0 | 68.1 | 69.3 | 71.5 | 71.5 | 74.6 |
| (ton miles per thousand Btu) | | | | | | | | | |
| Rail | 3.4 | 3.4 | 3.5 | 3.5 | 3.6 | 3.4 | 3.5 | 3.5 | 3.7 |
| Domestic shipping | 2.4 | 2.4 | 2.5 | 2.5 | 2.6 | 2.4 | 2.6 | 2.6 | 2.7 |
| **Energy use by mode (quadrillion Btu)** | | | | | | | | | |
| Light-duty vehicles | 15.56 | 14.29 | 12.77 | 13.02 | 10.41 | 14.64 | 12.43 | 12.72 | 8.47 |
| Commercial light trucks[1] | 0.54 | 0.59 | 0.53 | 0.54 | 0.50 | 0.66 | 0.57 | 0.58 | 0.50 |
| Bus transportation | 0.25 | 0.29 | 0.29 | 0.29 | 0.29 | 0.32 | 0.32 | 0.32 | 0.32 |
| Freight trucks | 4.95 | 6.79 | 6.39 | 6.64 | 6.28 | 7.80 | 7.31 | 7.62 | 7.19 |
| Rail, passenger | 0.05 | 0.06 | 0.06 | 0.06 | 0.06 | 0.07 | 0.06 | 0.06 | 0.06 |
| Rail, freight | 0.45 | 0.55 | 0.54 | 0.50 | 0.51 | 0.58 | 0.57 | 0.55 | 0.55 |
| Shipping, domestic | 0.21 | 0.24 | 0.23 | 0.30 | 0.29 | 0.24 | 0.23 | 0.30 | 0.29 |
| Shipping, international | 0.80 | 0.83 | 0.82 | 0.82 | 0.82 | 0.84 | 0.84 | 0.84 | 0.83 |
| Recreational boats | 0.24 | 0.27 | 0.28 | 0.28 | 0.28 | 0.28 | 0.29 | 0.30 | 0.30 |
| Air | 2.46 | 2.82 | 2.78 | 2.79 | 2.75 | 2.94 | 2.86 | 2.86 | 2.75 |
| Military use | 0.74 | 0.68 | 0.68 | 0.68 | 0.68 | 0.77 | 0.77 | 0.77 | 0.77 |
| Lubricants | 0.13 | 0.12 | 0.12 | 0.13 | 0.13 | 0.13 | 0.13 | 0.13 | 0.13 |
| Pipeline fuel | 0.70 | 0.69 | 0.74 | 0.86 | 0.87 | 0.69 | 0.78 | 0.99 | 0.99 |
| **Total** | **27.09** | **28.23** | **26.24** | **26.92** | **23.88** | **29.95** | **27.14** | **28.03** | **23.16** |

## Table D12. Key transportation results, oil import cases (continued)

| Consumption and indicators | 2011 | 2030 | | | | 2040 | | | |
|---|---|---|---|---|---|---|---|---|---|
| | | High Net Imports | Reference | High Oil and Gas Resource | Low/No Net Imports | High Net Imports | Reference | High Oil and Gas Resource | Low/No Net Imports |
| **Energy use by fuel (quadrillion Btu)** | | | | | | | | | |
| Propane | 0.06 | 0.08 | 0.07 | 0.08 | 0.07 | 0.10 | 0.08 | 0.09 | 0.07 |
| E85[5] | 0.05 | 0.15 | 0.16 | 0.17 | 0.43 | 0.20 | 0.17 | 0.16 | 0.65 |
| Motor gasoline[6] | 16.31 | 14.57 | 13.06 | 13.32 | 10.53 | 14.77 | 12.64 | 12.98 | 8.31 |
| Jet fuel[7] | 3.01 | 3.32 | 3.28 | 3.28 | 3.24 | 3.50 | 3.42 | 3.42 | 3.32 |
| Distillate fuel oil[8] | 5.91 | 8.00 | 7.61 | 7.86 | 6.89 | 8.26 | 7.90 | 8.22 | 7.34 |
| Residual fuel oil | 0.82 | 0.86 | 0.86 | 0.87 | 0.87 | 0.88 | 0.87 | 0.89 | 0.88 |
| Other petroleum[9] | 0.17 | 0.16 | 0.16 | 0.16 | 0.16 | 0.16 | 0.16 | 0.16 | 0.16 |
| Liquid fuels subtotal | 26.32 | 27.13 | 25.20 | 25.74 | 22.20 | 27.87 | 25.24 | 25.92 | 20.73 |
| Pipeline fuel natural gas | 0.70 | 0.69 | 0.74 | 0.86 | 0.87 | 0.69 | 0.78 | 0.99 | 0.99 |
| Compressed / liquefied natural gas | 0.04 | 0.36 | 0.26 | 0.27 | 0.71 | 1.31 | 1.05 | 1.06 | 1.29 |
| Liquid hydrogen | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| Electricity | 0.02 | 0.04 | 0.04 | 0.04 | 0.09 | 0.07 | 0.07 | 0.06 | 0.15 |
| **Delivered energy** | **27.09** | **28.23** | **26.25** | **26.92** | **23.88** | **29.95** | **27.14** | **28.03** | **23.16** |
| Electricity related losses | 0.05 | 0.09 | 0.09 | 0.08 | 0.18 | 0.14 | 0.13 | 0.12 | 0.26 |
| **Total** | **27.13** | **28.32** | **26.33** | **27.01** | **24.05** | **30.09** | **27.27** | **28.15** | **23.42** |

[1]Commercial trucks 8,501 to 10,000 pounds gross vehicle weight rating.
[2]Environmental Protection Agency rated miles per gallon.
[3]Tested new vehicle efficiency revised for on-road performance.
[4]Combined "on-the-road" estimate for all cars and light trucks.
[5]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.
[6]Includes ethanol (blends of 15 percent or less) and ethers blended into gasoline.
[7]Includes only kerosene type.
[8]Diesel fuel for on- and off- road use.
[9]Includes aviation gasoline and lubricants.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Data for 2011 are model results and may differ slightly from official EIA data reports.
**Source:** 2011 consumption based on: U.S. Energy Information Administration (EIA), *Annual Energy Review 2011*, DOE/EIA-0384(2011) (Washington, DC, September 2012). Other 2011 data: Federal Highway Administration, *Highway Statistics 2010* (Washington, DC, February 2012); Oak Ridge National Laboratory, *Transportation Energy Data Book: Edition 31* (Oak Ridge, TN, July 2012); National Highway Traffic and Safety Administration, *Summary of Fuel Economy Performance* (Washington, DC, October 28, 2010); U.S. Department of Commerce, Bureau of the Census, "Vehicle Inventory and Use Survey", EC02TV (Washington, DC, December 2004); EIA, Alternatives to Traditional Transportation Fuels 2009 (Part II – User and Fuel Data), April 2011; EIA, *State Energy Data Report 2010*, DOE/EIA-0214(2010) (Washington, DC, June 2012); U.S. Department of Transportation, Research and Special Programs Administration, *Air Carrier Statistics Monthly, December 2010-2009* (Washington, DC, December 2010); and United States Department of Defense, Defense Fuel Supply Center, Factbook (January, 2010). **Projections:** EIA, AEO2013 National Energy Modeling System runs HIGHIMPORT.D012813A, REF2013.D102312A, HIGHRESOURCE.D021413A, and LOWIMPORT.D021113B.

## Table D13. Key results for No Greenhouse Gas Concern case
(million short tons per year, unless otherwise noted)

| Supply, disposition, prices, and electricity generating capacity additions | 2011 | 2020 | | 2030 | | 2040 | |
|---|---|---|---|---|---|---|---|
| | | Reference | No GHG Concern | Reference | No GHG Concern | Reference | No GHG Concern |
| Production[1] | 1,096 | 1,071 | 1,080 | 1,153 | 1,149 | 1,167 | 1,211 |
| Appalachia | 337 | 288 | 290 | 295 | 298 | 283 | 284 |
| Interior | 171 | 198 | 198 | 212 | 213 | 226 | 248 |
| West | 588 | 585 | 592 | 646 | 638 | 658 | 679 |
| Waste coal supplied[2] | 13 | 19 | 19 | 20 | 20 | 27 | 29 |
| Net imports[3] | -96 | -125 | -125 | -139 | -133 | -123 | -111 |
| **Total supply[4]** | **1,012** | **966** | **974** | **1,034** | **1,036** | **1,071** | **1,128** |
| **Consumption by sector** | | | | | | | |
| Residential and commercial | 3 | 3 | 3 | 3 | 3 | 3 | 3 |
| Coke plants | 21 | 23 | 23 | 20 | 20 | 18 | 18 |
| Other industrial[5] | 46 | 50 | 50 | 50 | 50 | 52 | 52 |
| Coal-to-liquids heat and power | 0 | 0 | 0 | 5 | 2 | 8 | 4 |
| Coal-to-liquids liquids production | 0 | 0 | 0 | 4 | 2 | 6 | 3 |
| Electric power[6] | 929 | 890 | 898 | 953 | 960 | 984 | 1,048 |
| **Total coal consumption** | **999** | **966** | **974** | **1,034** | **1,036** | **1,071** | **1,128** |
| **Average minemouth price[7]** | | | | | | | |
| (2011 dollars per short ton) | 41.16 | 49.26 | 49.13 | 55.64 | 55.83 | 61.28 | 61.15 |
| (2011 dollars per million Btu) | 2.04 | 2.45 | 2.45 | 2.79 | 2.79 | 3.08 | 3.09 |
| **Delivered prices[8] (2011 dollars per short ton)** | | | | | | | |
| Coke plants | 184.44 | 229.19 | 228.99 | 264.13 | 263.97 | 290.84 | 290.85 |
| Other industrial[5] | 70.68 | 72.44 | 72.48 | 78.25 | 78.24 | 85.63 | 86.67 |
| Coal to liquids | - - | - - | - - | 47.71 | 55.16 | 55.60 | 52.25 |
| Electric power[6] | | | | | | | |
| (2011 dollars per short ton) | 46.38 | 47.91 | 47.86 | 54.37 | 54.44 | 60.77 | 61.34 |
| (2011 dollars per million Btu) | 2.38 | 2.52 | 2.51 | 2.87 | 2.87 | 3.20 | 3.24 |
| **Average** | **50.64** | **53.47** | **53.39** | **59.53** | **59.64** | **65.70** | **66.04** |
| Exports[9] | 148.86 | 168.73 | 168.93 | 177.76 | 177.62 | 176.05 | 173.77 |
| **Cumulative electricity generating capacity additions (gigawatts)[10]** | | | | | | | |
| Coal | 0.0 | 6.4 | 6.4 | 7.2 | 8.4 | 8.8 | 25.7 |
| Conventional | 0.0 | 4.9 | 4.9 | 4.9 | 6.5 | 6.1 | 23.6 |
| Advanced without sequestration | 0.0 | 0.6 | 0.6 | 0.6 | 0.6 | 0.6 | 0.6 |
| Advanced with sequestration | 0.0 | 0.9 | 0.9 | 0.9 | 0.9 | 0.9 | 0.9 |
| End-use generators[11] | 0.0 | 0.0 | 0.0 | 0.8 | 0.4 | 1.3 | 0.7 |
| Petroleum | 0.0 | 0.3 | 0.3 | 0.3 | 0.3 | 0.3 | 0.3 |
| Natural gas | 0.0 | 38.1 | 37.4 | 120.2 | 117.1 | 215.2 | 209.4 |
| Nuclear / uranium | 0.0 | 5.5 | 5.5 | 5.5 | 5.5 | 11.0 | 6.1 |
| Renewables[12] | 0.0 | 37.1 | 37.4 | 48.8 | 47.8 | 104.3 | 84.8 |
| Other | 0.0 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 |
| **Total** | **0.0** | **87.6** | **87.2** | **182.2** | **179.2** | **339.9** | **326.4** |
| Liquids from coal (million barrels per day) | 0.00 | 0.00 | 0.00 | 0.04 | 0.02 | 0.06 | 0.03 |

[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 that have a non-regulatory status, and small on-site generating systems. Excludes all coal use in the coal-to-liquids process.
[6]Includes all electricity-only and combined heat and power plants that have a regulatory status.
[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 prices.
[9]Free-alongside-ship price at U.S. port of exit.
[10]Cumulative additions after December 31, 2011. 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 that have a non-regulatory status. 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.
[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 2011 are model results and may differ slightly from official EIA data reports.
**Sources:** 2011 data based on: U.S. Energy Information Administration (EIA), *Annual Coal Report 2011*, DOE/EIA-0584(2011) (Washington, DC, November 2012); EIA, *Quarterly Coal Report, October-December 2011*, DOE/EIA-0121(2011/4Q) (Washington, DC, March 2012); and EIA, AEO2013 National Energy Modeling System run REF2013.D102312A. **Projections:** EIA, AEO2013 National Energy Modeling System runs REF2013.D102312A and NOGHGCONCERN.D110912A.

## Table D14. Key results for coal cost cases
(million short tons per year, unless otherwise noted)

| Supply, disposition, prices, electricity generating capacity additions, and costs | 2011 | 2020 | | | 2040 | | | Annual growth 2011-2040 (percent) | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | | Low Coal Cost | Reference | High Coal Cost | Low Coal Cost | Reference | High Coal Cost | Low Coal Cost | Reference | High Coal Cost |
| Production[1] | 1,096 | 1,129 | 1,071 | 985 | 1,363 | 1,167 | 838 | 0.8% | 0.2% | -0.9% |
| Appalachia | 337 | 300 | 288 | 276 | 345 | 283 | 243 | 0.1% | -0.6% | -1.1% |
| Interior | 171 | 210 | 198 | 185 | 253 | 226 | 191 | 1.4% | 1.0% | 0.4% |
| West | 588 | 619 | 585 | 525 | 764 | 658 | 404 | 0.9% | 0.4% | -1.3% |
| Waste coal supplied[2] | 13 | 16 | 19 | 20 | 13 | 27 | 47 | 0.1% | 2.7% | 4.6% |
| Net imports[3] | -96 | -129 | -125 | -123 | -206 | -123 | -78 | 2.7% | 0.9% | -0.7% |
| **Total supply[4]** | **1,012** | **1,016** | **966** | **882** | **1,170** | **1,071** | **806** | **0.5%** | **0.2%** | **-0.8%** |
| **Consumption by sector** | | | | | | | | | | |
| Residential and commercial | 3 | 3 | 3 | 3 | 3 | 3 | 2 | -0.2% | -0.3% | -0.4% |
| Coke plants | 21 | 23 | 23 | 23 | 18 | 18 | 17 | -0.6% | -0.7% | -0.8% |
| Other industrial[5] | 46 | 50 | 50 | 50 | 52 | 52 | 51 | 0.4% | 0.4% | 0.3% |
| Coal-to-liquids heat and power | 0 | 5 | 0 | 0 | 13 | 8 | 0 | - - | - - | - - |
| Coal-to-liquids liquids production | 0 | 4 | 0 | 0 | 10 | 6 | 0 | - - | - - | - - |
| Electric power[6] | 929 | 932 | 890 | 807 | 1,075 | 984 | 735 | 0.5% | 0.2% | -0.8% |
| **Total coal use** | **999** | **1,016** | **966** | **882** | **1,170** | **1,071** | **807** | **0.5%** | **0.2%** | **-0.7%** |
| **Average minemouth price[7]** | | | | | | | | | | |
| (2011 dollars per short ton) | 41.16 | 40.89 | 49.26 | 61.11 | 33.90 | 61.28 | 128.09 | -0.7% | 1.4% | 4.0% |
| (2011 dollars per million Btu) | 2.04 | 2.04 | 2.45 | 3.02 | 1.70 | 3.08 | 6.20 | -0.6% | 1.4% | 3.9% |
| **Delivered prices[8] (2011 dollars per short ton)** | | | | | | | | | | |
| Coke plants | 184.44 | 198.35 | 229.19 | 264.37 | 178.75 | 290.84 | 475.91 | -0.1% | 1.6% | 3.3% |
| Other industrial[5] | 70.68 | 63.21 | 72.44 | 83.01 | 53.10 | 85.63 | 145.06 | -1.0% | 0.7% | 2.5% |
| Coal to liquids | - - | 29.33 | - - | - - | 27.23 | 55.60 | 107.69 | - - | - - | - - |
| Electric power[6] | | | | | | | | | | |
| (2011 dollars per short ton) | 46.38 | 41.46 | 47.91 | 56.00 | 35.63 | 60.77 | 110.99 | -0.9% | 0.9% | 3.1% |
| (2011 dollars per million Btu) | 2.38 | 2.17 | 2.52 | 2.93 | 1.88 | 3.20 | 5.68 | -0.8% | 1.0% | 3.0% |
| **Average** | **50.64** | **46.00** | **53.47** | **62.86** | **38.45** | **65.70** | **120.95** | **-0.9%** | **0.9%** | **3.0%** |
| Exports[9] | 148.86 | 147.66 | 168.73 | 194.63 | 117.53 | 176.05 | 317.96 | -0.8% | 0.6% | 2.7% |
| **Cumulative electricity generating capacity additions (gigawatts)[10]** | | | | | | | | | | |
| Coal | 0.0 | 7.1 | 6.4 | 6.4 | 16.2 | 8.8 | 6.5 | - - | - - | - - |
| Conventional | 0.0 | 4.9 | 4.9 | 4.9 | 12.9 | 6.1 | 4.9 | - - | - - | - - |
| Advanced without sequestration | 0.0 | 0.6 | 0.6 | 0.6 | 0.6 | 0.6 | 0.6 | - - | - - | - - |
| Advanced with sequestration | 0.0 | 0.9 | 0.9 | 0.9 | 0.9 | 0.9 | 0.9 | - - | - - | - - |
| End-use generators[11] | 0.0 | 0.7 | 0.0 | 0.0 | 1.8 | 1.3 | 0.1 | - - | - - | - - |
| Petroleum | 0.0 | 0.3 | 0.3 | 0.3 | 0.3 | 0.3 | 0.3 | - - | - - | - - |
| Natural gas | 0.0 | 37.0 | 38.1 | 37.3 | 210.7 | 215.2 | 221.8 | - - | - - | - - |
| Nuclear / uranium | 0.0 | 5.5 | 5.5 | 5.5 | 8.6 | 11.0 | 8.7 | - - | - - | - - |
| Renewables[12] | 0.0 | 38.4 | 37.1 | 38.2 | 111.4 | 104.3 | 90.3 | - - | - - | - - |
| Other | 0.0 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 | - - | - - | - - |
| **Total** | **0.0** | **88.5** | **87.6** | **87.9** | **347.3** | **339.9** | **327.7** | - - | - - | - - |
| Liquids from coal (million barrels per day) | 0.00 | 0.03 | 0.00 | 0.00 | 0.09 | 0.06 | 0.00 | - - | - - | - - |

## Table D14. Key results for coal cost cases (continued)
(million short tons per year, unless otherwise noted)

| Supply, disposition, and prices | 2011 | 2020 | | | 2040 | | | Annual growth 2011-2040 (percent) | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | | 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, 2011=1.000)** | | | | | | | | | | |
| Transportation rate multipliers | | | | | | | | | | |
| Eastern railroads | 1.000 | 0.950 | 1.028 | 1.070 | 0.750 | 1.003 | 1.240 | -1.0% | 0.0% | 0.7% |
| Western railroads | 1.000 | 0.920 | 0.989 | 1.060 | 0.760 | 1.013 | 1.270 | -0.9% | 0.0% | 0.8% |
| Mine equipment costs | | | | | | | | | | |
| Underground | 1.000 | 0.923 | 1.000 | 1.083 | 0.755 | 1.000 | 1.321 | -1.0% | 0.0% | 1.0% |
| Surface | 1.000 | 0.923 | 1.000 | 1.083 | 0.755 | 1.000 | 1.321 | -1.0% | 0.0% | 1.0% |
| Other mine supply costs | | | | | | | | | | |
| East of the Mississippi: all mines | 1.000 | 0.923 | 1.000 | 1.083 | 0.755 | 1.000 | 1.321 | -1.0% | 0.0% | 1.0% |
| West of the Mississippi: underground | 1.000 | 0.923 | 1.000 | 1.083 | 0.755 | 1.000 | 1.321 | -1.0% | 0.0% | 1.0% |
| West of the Mississippi: surface | 1.000 | 0.923 | 1.000 | 1.083 | 0.755 | 1.000 | 1.321 | -1.0% | 0.0% | 1.0% |
| Coal mining labor productivity (short tons per miner per hour) | 5.19 | 5.45 | 4.43 | 3.49 | 6.68 | 3.47 | 1.44 | 0.9% | -1.4% | -4.3% |
| Average coal miner wage (2011 dollars per year) | 81,258 | 87,721 | 95,199 | 102,572 | 80,105 | 105,676 | 138,365 | 0.0% | 0.9% | 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 that have a non-regulatory status, and small on-site generating systems. Excludes all coal use in the coal to liquids process.
[6]Includes all electricity-only and combined heat and power plants that have a regulatory status.
[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 prices.
[9]Free-alongside-ship price at U.S. port of exit.
[10]Cumulative additions after December 31, 2011. 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 that have a non-regulatory status. 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.
[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 2011 are model results and may differ slightly from official EIA data reports.
**Sources:** 2011 data based on: U.S. Energy Information Administration (EIA), *Annual Coal Report 2011*, DOE/EIA-0584(2011) (Washington, DC, November 2012); EIA, *Quarterly Coal Report, October-December 2011*, DOE/EIA-0121(2011/4Q) (Washington, DC, March 2012); U.S. Department of Labor, Bureau of Labor Statistics, Average Hourly Earnings of Production Workers: Coal Mining, Series ID : ceu1021210008; and EIA, AEO2013 National Energy Modeling System run REF2013.D102312A. **Projections:** EIA, AEO2013 National Energy Modeling System runs LCCST13.D112112A, REF2013.D102312A, and HCCST13.D112112A.

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## Appendix E

# NEMS overview and brief description of cases

### The National Energy Modeling System

Projections in the *Annual Energy Outlook 2013 (AEO2013)* are generated using the National Energy Modeling System (NEMS) [*148*], developed and maintained by the Office of Energy Analysis 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 to complete 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. NEMS is also used by other nongovernment groups, such as the Electric Power Research Institute, Duke University, and Georgia Institute of Technology. In addition, the *AEO* projections are 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, subject to regulations and standards. 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 extends to 2040. To represent regional differences in energy markets, the component modules of NEMS function at the regional level: the 9 Census divisions for the end-use demand modules; production regions specific to oil, natural gas, and coal supply and distribution; 22 regions and subregions of the North American Electric Reliability Corporation for electricity; and 9 refining regions that are a subset of the 5 Petroleum Administration for Defense Districts (PADDs).

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. The modular design also permits the use of the methodology and level of detail most appropriate for each energy sector. NEMS executes each of the component modules to solve for prices of energy delivered 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 such areas as economic activity, domestic production, and international petroleum supply. 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 for each year from 2012 through 2040. 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 energy-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 *AEO2013* generally represents current legislation and environmental regulations, including recent government actions for which implementing regulations were available as of September 30, 2012, as discussed in the "Legislation and regulations" section of the *AEO*. 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. Many of the pending provisions, however, are examined in alternative cases included in *AEO2013* or in other analysis completed by EIA.

In general, the historical data presented with the *AEO2013* projections are based on EIA's *Annual Energy Review 2011*, published in September 2012 [*149*]; however, data were taken from multiple sources. In some cases, only partial or preliminary data were available for 2011. Historical numbers are presented for comparison only and may be estimates. Source documents should be consulted for the official data values. Footnotes to the *AEO2013* appendix tables indicate the definitions and sources of historical data.

Where possible, the *AEO2013* projections for 2012 and 2013 incorporate short-term projections from EIA's September 2012 *Short-Term Energy Outlook (STEO)* [*150*]. EIA's views regarding energy use over the 2012 through 2014 period are reported in monthly updates of the *STEO* [*151*], which should be considered to supersede information reported for those years in *AEO2013*.

### 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 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 quantities. 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 Energy Module

The International Energy Module (IEM) uses assumptions of economic growth and expectations of future U.S. and world petroleum and other liquids production and consumption, by year, to project the interaction of U.S. and international petroleum and other liquids markets. The IEM provides a world crude-like liquids supply curve and generates a worldwide oil supply/demand balance for each year of the projection period. 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 petroleum and other liquids supply and demand, current investment trends in exploration and development, and long-term resource economics by country and territory. The oil production estimates include both petroleum and other liquids supply recovery technologies. The IEM also provides, for each year of the projection period, endogenous and exogenous assumptions for petroleum products for import and export in the United States. In interacting with the rest of NEMS, the IEM changes Brent and West Texas Intermediate (WTI) prices in response to changes in expected production and consumption of crude oil and other liquids in the United States.

## Residential and Commercial Demand Modules

The Residential Demand Module projects energy consumption in the residential sector by Census division, housing type, and end use, based on delivered energy prices, the menu of equipment available, the availability of renewable sources of energy, and changes in the housing stock. The Commercial Demand Module projects energy consumption in the commercial sector by Census division, building type, and category of end use, based on delivered prices of energy, the menu of available equipment, availability of renewable sources of energy, and changes in commercial floorspace.

Both modules estimate the equipment stock for the major end-use services, incorporating assessments of advanced technologies, representations of renewable energy technologies, and the effects of both building shell and appliance standards. The modules also include projections of distributed generation. The Commercial Demand Module also incorporates combined heat and power (CHP) technology. Both modules incorporate changes to "normal" heating and cooling degree-days by Census division, based on a 30-year historical trend 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 new construction and remodeling.

## Industrial Demand Module

The Industrial Demand Module (IDM) projects the consumption of energy for heat and power, as well as the consumption of feedstocks and raw materials in each of 21 industry groups, subject to the delivered prices of energy and macroeconomic estimates of employment and the value of shipments for each industry. As noted in the description of the MAM, the representation of industrial activity in NEMS is based on the NAICS. The industries are classified into three groups—energy-intensive manufacturing, non-energy-intensive manufacturing, and nonmanufacturing. Seven of eight energy-intensive manufacturing industries are modeled in the IDM, including energy-consuming components for boiler/steam/cogeneration, buildings, and process/assembly use of energy. Energy demand for petroleum and other liquids refining (the eighth energy-intensive manufacturing industry) is modeled in the Liquid Fuels Market Module (LFMM) as described below, but the projected consumption is reported under the industrial totals.

There are several updates and upgrades in the representations of select industries. *AEO2013* includes an upgraded representation for the aluminum industry. Instead of assuming that technological development for a particular process occurs on a predetermined or exogenous path based on engineering judgment, these upgrades allow IDM technological change to be modeled endogenously, while using more detailed process representation. The upgrade allows for explicit technological change, and therefore energy intensity, to respond to economic, regulatory, and other conditions. The combined cement and lime industry was upgraded in the *Annual Energy Outlook 2012 (AEO2012).* For subsequent *AEO*s other energy-intensive industries will be similarly upgraded.

The bulk chemicals model has been enhanced in several respects: baseline natural gas liquids feedstock data were aligned with Manufacturing Energy Consumption Survey 2006 data; an updated propane pricing mechanism reflecting natural gas price influences was used to allow for price competition between liquefied petroleum gas feedstock and petroleum-based (naphtha) feedstock; and propylene supplied by the refining industry is now specifically accounted for in the LFMM.

Nonmanufacturing models were significantly revised as well. The construction and mining models were augmented to better reflect NEMS assumptions regarding energy efficiencies in (off-road) vehicles and buildings, as well as coal, oil, and natural gas extraction productivity. The agriculture model was similarly augmented in *AEO2012*. The IDM also includes a generalized representation of CHP. The methodology for CHP systems simulates the utilization of installed CHP systems based on historical utilization rates and is driven by end-use electricity demand. To evaluate the economic benefits of additional CHP capacity, the model also includes an appraisal incorporating historical capacity factors and regional acceptance rates for new CHP facilities.

There are also enhancements to the IDM to account for regulatory changes. This includes the State of California's Global Warming Solutions Act (AB 32) that allows for representation of a cap-and-trade program developed as part of California's greenhouse gas (GHG) emissions reduction goals for 2020. Another regulatory update is included for the handling of National Emissions Standards for Hazardous Air Pollutants for industrial boilers, to address the maximum degree of emission reduction using maximum achievable control technology (MACT).

### Transportation Demand Module

The Transportation Demand Module projects consumption of energy by mode and fuel—including petroleum products, electricity, methanol, ethanol, compressed natural gas (CNG), liquefied natural gas (LNG), and hydrogen—in the transportation sector, subject to delivered energy prices, macroeconomic variables such as GDP, and other factors such as technology adoption. The Transportation Demand Module includes legislation and regulations, such as the Energy Policy Act of 2005 (EPACT2005), the Energy Improvement and Extension Act of 2008 (EIEA2008), and the American Recovery and Reinvestment Act of 2009 (ARRA2009), which contain tax credits for the purchase of alternatively fueled vehicles. Representations of LDV corporate average fuel economy (CAFE) and GHG emissions standards, HDV fuel consumption and GHG emissions standards, and biofuels consumption reflect standards enacted by the National Highway Traffic Safety Administration (NHTSA) and the U.S. Environmental Protection Agency (EPA), as well as provisions in the Energy Independence and Security Act of 2007 (EISA2007).

The air transportation component of the Transportation Demand Module 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. For passenger travel and air freight shipments, the module represents regional fuel use and travel demand for three aircraft types: regional, narrow-body, and wide-body. 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.

The Transportation Demand Module projects energy consumption for freight and passenger rail and marine vessels by mode and fuel, subject to macroeconomic variables such as the value and type of industrial shipments.

### Electricity Market Module

There are three primary submodules of the Electricity Market Module (EMM)—capacity planning, fuel dispatching, and finance and pricing. The capacity expansion submodule uses the stock of existing generation capacity, known environmental regulations, the expected cost and performance of future generation capacity, expected fuel prices, expected financial parameters, and expected electricity demand to project the optimal mix of new generation capacity that should be added in future years. The fuel dispatching submodule uses the existing stock of generation equipment types, their operation and maintenance 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 determines transmission and pricing of electricity. The finance and pricing submodule uses capital costs, fuel costs, macroeconomic parameters, environmental regulations, and 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 are explicitly represented in the capacity expansion and dispatch decisions. All financial incentives for power generation expansion and dispatch specifically identified in EPACT2005 have been implemented. Several States, primarily in the Northeast, have enacted air emission regulations for $CO_2$ that affect the electricity generation sector, and those regulations are represented in *AEO2013*. The *AEO2013* Reference case also imposes a limit on $CO_2$ emissions for specific covered sectors, including the electric power sector, in California, as represented in California's AB 32. The *AEO2013* Reference case leaves the Clean Air Interstate Rule (CAIR) in effect after the court vacated the Cross-State Air Pollution Rule (CSAPR) in August 2012. CAIR incorporates a cap and trade program for annual emissions of $SO_2$ and annual and seasonal emissions of $NO_X$ from fossil power plants. Reductions in hazardous air pollutant emissions from coal- and oil-fired steam electric power plants also are reflected through the inclusion of the Mercury and Air Toxics Standards for power plants, finalized by the EPA on December 16, 2011.

Although currently there is no Federal legislation in place that restricts 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 *AEO2013* Reference case through a 3-percentage-point increase in the cost of capital, when evaluating investments in new coal-fired power plants, new coal-to-liquids (CTL) plants without carbon capture and storage (CCS), and pollution control retrofits.

### Renewable Fuels Module

The Renewable Fuels Module (RFM) includes submodules representing renewable resource supply and technology input information for central-station, grid-connected electricity generation technologies, including conventional hydroelectricity, biomass (dedicated biomass plants and co-firing in existing coal plants), geothermal, landfill gas, solar thermal electricity, solar photovoltaics (PV), and both onshore and offshore 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. The extension of the credit to individual homeowners under EIEA2008 is reflected in the Residential and Commercial Demand Modules.

PTCs for wind, geothermal, landfill gas, and some types of hydroelectric and biomass-fueled plants also are represented, based on the laws in effect on October 31, 2012. They provide a credit of up to 2.2 cents per kilowatthour for electricity produced in the first 10 years of plant operation. For *AEO2013*, 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. The law was subsequently amended to extend the PTC for wind. The impact of this amendment is considered in the American Taxpayer Relief Act of 2012 case discussed in the "Issues in focus" section of *AEO2013*. Furthermore, eligible plants of any type will qualify if construction begins prior to the expiration date, regardless of when the plant enters commercial service. This change was made after the completion of *AEO2013* and is not reflected in the analysis. As part of ARRA2009, plants eligible for the PTC may instead elect to receive a 30-percent ITC or an equivalent direct grant. *AEO2013* also accounts for new renewable energy capacity resulting from state renewable portfolio standard programs, mandates, and goals, as described in *Assumptions to the Annual Energy Outlook 2013* [*152*].

## Oil and Gas Supply Module

The Oil and Gas Supply Module represents domestic crude oil and natural gas supply within an integrated framework that captures the interrelationships among the various sources of supply—onshore, offshore, and Alaska—by 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 Onshore Lower 48 Oil and Gas Supply Submodule evaluates the economics of future exploration and development projects for crude oil and natural gas at the play level. Crude oil resources include conventional, structurally reservoired resources as well as highly fractured continuous zones, such as the Austin chalk and Bakken shale formations. Production potential from advanced secondary recovery techniques (such as infill drilling, horizontal continuity, and horizontal profile) and enhanced oil recovery (such as $CO_2$ flooding, steam flooding, polymer flooding, and profile modification) are explicitly represented. Natural gas resources include high-permeability carbonate and sandstone, tight gas, shale gas, and coalbed methane.

Domestic crude oil production quantities are used as inputs to the LFMM 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 (NGTDM) for determining natural gas wellhead prices and domestic production.

## Natural Gas Transmission and Distribution Module

The NGTDM represents the transmission, distribution, and pricing of natural gas, subject to end-use demand for natural gas and the availability of domestic natural gas and natural gas traded on the international market. The module tracks the flows of natural gas and determines the associated capacity expansion requirements in an aggregate pipeline network, connecting the domestic and foreign supply regions with 12 lower 48 U.S. demand regions. The 12 lower 48 regions align with the 9 Census divisions, with three subdivided, and Alaska handled separately. The flow of natural gas is determined for both a peak and off-peak period in the year, assuming a historically based seasonal distribution of natural gas demand. Key components of pipeline and distributor tariffs are included in separate pricing algorithms. An algorithm is included to project the addition of CNG retail fueling capability. The module also accounts for foreign sources of natural gas, including pipeline imports and exports to Canada and Mexico, as well as LNG imports and exports.

## Liquid Fuels Market Module

The LFMM projects prices of petroleum products, crude oil and product import activity, as well as domestic refinery operations, subject to demand for petroleum products, availability and price of imported petroleum, and domestic production of crude oil, natural gas liquids, and biofuels—ethanol, biodiesel, biomass-to-liquids (BTL), CTL, gas-to-liquids (GTL), and coal-and-biomass-to-liquids (CBTL). Costs, performance, and first dates of commercial availability for the advanced liquid fuels technologies [*153*] are reviewed and updated annually.

The module represents refining activities in eight domestic U.S. regions, and a new Maritime Canada/Caribbean refining region (created to represent short-haul international refineries that predominantly serve U.S. markets). In order to better represent policy, import/export patterns, and biofuels production, the eight U.S. regions were defined by subdividing three of the five U.S. PADDs. All nine refining regions are defined below.

Region 1. PADD I – East Coast

Region 2. PADD II – Interior

Region 3. PADD II – Great Lakes

Region 4. PADD III – Gulf Coast

Region 5. PADD III – Interior

Region 6. PADD IV – Mountain

Region 7. PADD V – California

Region 8. PADD V – Other

Region 9. Maritime Canada/Caribbean

The capacity expansion submodule uses the stock of existing generation capacity, the cost and performance of future generation capacity, expected fuel prices, expected financial parameters, expected electricity demand, and expected environmental regulations to project the optimal mix of new generation capacity that should be added in future years.

The LFMM models the costs of automotive fuels, such as conventional and reformulated gasoline, and includes production of biofuels for blending in gasoline and diesel. Fuel ethanol and biodiesel are included in the LFMM, because they are commonly blended into petroleum products. The module allows ethanol blending into gasoline at 10 percent by volume, 15 percent by volume (E15) in states that lack explicit language capping ethanol volume or oxygen content, and up to 85 percent by volume (E85) for use in flex-fuel vehicles. Crude and refinery product imports are represented by supply curves defined by the NEMS IEM. Products also can be imported from refining region 9 (Maritime Canada/Caribbean). Refinery product exports are provided by the IEM.

Capacity expansion of refinery process units and nonpetroleum liquid fuels production facilities is also modeled in the LFMM. The model uses current liquid fuels production capacity, the cost and performance of each production unit, expected fuel and feedstock costs, expected financial parameters, expected liquid fuels demand, and relevant environmental policies to project the optimal mix of new capacity that should be added in the future.

The LFMM includes representation of the renewable fuels standard (RFS) specified in EISA2007, which mandates the use of 36 billion gallons of ethanol equivalent renewable fuel by 2022. Both domestic and imported biofuels count toward the RFS. Domestic ethanol production is modeled for three feedstock categories: corn, cellulosic plant materials, and advanced feedstock materials. Starch-based ethanol plants are numerous (more than 190 are now in operation, with a total maximum sustainable nameplate capacity of more than 14 billion gallons annually), and they 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. Ethanol from advanced feedstocks—produced at ethanol refineries that ferment and distill grains other than corn, and reduce GHG emissions by at least 50 percent—is also a new technology modeled in the LFMM.

Fuels produced by Fischer-Tropsch synthesis and through a pyrolysis process are also modeled in the LFMM, based on their economics relative to competing feedstocks and products. The five processes modeled are CTL, CBTL, GTL, BTL, and pyrolysis.

Two California-specific policies are also represented in the LFMM: the low carbon fuel standard (LCFS) and the AB 32 cap-and-trade program. The LCFS requires the carbon intensity (amount of greenhouse gases per unit of energy) of transportation fuels sold for use in California to decrease according to a schedule published by the California Air Resources Board. California's AB 32 cap-and-trade program is established to help California achieve its goal of reducing $CO_2$ emissions to 1990 levels by 2020. Working with other NEMS modules (IDM, EMM, and Emissions Policy Module), the LFMM provides emissions allowances and actual emissions of $CO_2$ from California refineries, and NEMS provides the mechanism (carbon price) to trade allowances such that the total $CO_2$ emissions cap is met.

### 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 41 separate supply curves—differentiated by region, mine type, coal rank, and sulfur content. The coal supply curves respond to capacity utilization of mines, mining capacity, labor productivity, and factor input costs (mining equipment, mining labor, and fuel requirements). Projections of U.S. coal distribution are determined by minimizing the cost of coal supplied, given coal demands by 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 production and transportation costs while 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 2013* cases

Table E1 provides a summary of the cases produced as part of *AEO2013*. For each case, the table gives the name used in *AEO2013*, a brief description of the major assumptions underlying the projections, 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 in more detail. The Reference case assumptions for each sector are described in *Assumptions to the Annual Energy Outlook 2013* [*154*]. Regional results and other details of the projections are available at website www.eia.gov/forecasts/aeo/tables_ref.cfm#supplement.

### Macroeconomic growth cases

In addition to the *AEO2013* Reference case, 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:

- In the Reference case, population grows by 0.9 percent per year, nonfarm employment by 1.0 percent per year, and labor productivity by 1.9 percent per year from 2011 to 2040. Economic output as measured by real GDP increases by 2.5 percent per year from 2011 through 2040, and growth in real disposable income per capita averages 1.4 percent per year.
- The Low Economic Growth case assumes lower growth rates for population (0.8 percent per year) and labor productivity (1.4 percent per year), resulting in lower nonfarm employment (0.8 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 1.9 percent per year from 2011 through 2040, and growth in real disposable income per capita averages 1.2 percent per year.
- The High Economic Growth case assumes higher growth rates for population (1.0 percent per year) and labor productivity (2.1 percent per year), resulting in higher nonfarm employment (1.1 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 (2.9 percent per year) than in the Reference case (2.5 percent). Disposable income per capita grows by 1.6 percent per year, compared with 1.4 percent in the Reference case.

### Oil price cases

For *AEO2013*, the benchmark oil price is being re-characterized to represent Brent crude oil instead of WTI crude oil. This change is being made to better reflect the marginal price refineries pay for imported light, sweet crude oil, used to produce petroleum products for consumers. EIA will continue to report the WTI price, as it is a critical reference point to for evaluation of growing production in the mid-continent. EIA will also continue to report the Imported Refiner Acquisition Cost.

The historical record shows substantial variability in oil prices, and there is arguably even more uncertainty about future prices in the long term. *AEO2013* considers three oil price cases (Reference, Low Oil Price, and High Oil Price) to allow an assessment of alternative views on the future course of oil prices.

The Low and High Oil Price cases reflect a wide range of potential price paths, resulting from variation in demand by countries outside the Organization for Economic Cooperation and Development (OECD) for petroleum and other liquid fuels due to different levels of economic growth. The Low and High Oil Price cases also reflect different assumptions about decisions by members of the Organization of the Petroleum Exporting Countries (OPEC) regarding the preferred rate of oil production and about the future finding and development costs and accessibility of conventional structurally reservoired oil resources outside the United States.

- In the Reference case, real oil prices (in 2011 dollars) rise from $109 per barrel in 2011 to $163 per barrel in 2040. The Reference case represents EIA's current judgment regarding exploration and development costs and accessibility of oil resources. 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 oil production will represent between 40 and 43 percent of the world's total petroleum and other liquids production over the projection period.
- In the Low Oil Price case, crude oil prices are $75 per barrel (2011 dollars) in 2040. The low price results from lower demand for petroleum and other liquid fuels in the non-OECD nations. Lower demand is derived from lower economic growth relative to the Reference case. In this case, GDP growth in the non-OECD countries is lower on average relative to the Reference case in each projection year, beginning in 2013. The OECD projections are affected only by the price impact. On the supply side, OPEC countries increase their oil production to obtain a 49-percent share of total world petroleum and other liquids production in 2040, and oil resources outside the United States are 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.
- In the High Oil Price case, oil prices reach about $237 per barrel (2011 dollars) in 2040. The high prices result from higher demand for petroleum and other liquid fuels in the non-OECD nations. Higher demand is measured by higher economic growth relative to the Reference case. In this case, GDP growth in the non-OECD countries is higher on average relative to the Reference case in each projection year, beginning in 2013. The OECD projections are affected only by the price impact. On the supply side, OPEC countries reduce their market share to between 37 and 40 percent, and oil resources outside the United States are less accessible and/or more costly to produce than in the Reference case.

**Table E1. Summary of the *AEO2013* cases**

| Case name | Description | Reference in text | Reference in Appendix E |
|---|---|---|---|
| Reference | Real GDP grows at an average annual rate of 2.5 percent from 2011 to 2040. Crude oil prices rise to about $163 per barrel (2011 dollars) in 2040. Complete projection tables in Appendix A. | -- | -- |
| Low Economic Growth | Real GDP grows at an average annual rate of 1.9 percent from 2011 to 2040. Other energy market assumptions are the same as in the Reference case. Partial projection tables in Appendix B. | p. 56 | p. 214 |
| High Economic Growth | Real GDP grows at an average annual rate of 2.9 percent from 2011 to 2040. Other energy market assumptions are the same as in the Reference case. Partial projection tables in Appendix B. | p. 56 | p. 214 |
| Low Oil Price | Low prices result from a combination of low demand for petroleum and other liquids in the non-OECD nations and higher global supply. Lower demand is measured by lower economic growth relative to the Reference case. On the supply side, OPEC increases its market share to 49 percent, and the costs of other liquids production technologies are lower than in the Reference case. Light, sweet crude oil prices fall to $75 per barrel in 2040. Partial projection tables in Appendix C. | p. 31 | p. 214 |
| High Oil Price | High prices result from a combination of higher demand for petroleum and other liquids in the non-OECD nations and lower global supply. Higher demand is measured by higher economic growth relative to the Reference case. Non-OPEC petroleum production expands more slowly in the short to middle term relative to the Reference case. Crude oil prices rise to $237 per barrel (2011 dollars) in 2040. Partial projection tables in Appendix C. | p. 31 | p. 214 |
| No Sunset | Begins with the Reference case and assumes extension of all existing energy policies and legislation that contain sunset provisions, except those requiring additional funding (e.g., loan guarantee programs) and those that involve extensive regulatory analysis, such as CAFE improvements and periodic updates of efficiency standards. Partial projection tables in Appendix D. | p. 25 | p. 218 |
| Extended Policies | Begins with the No Sunset case and assumes an increase in the capacity limitations on the ITC and extension of the program. The case includes additional rounds of efficiency standards for residential and commercial products, as well as new standards for products not yet covered; adds multiple rounds of national building codes by 2026; and increases LDV fuel economy standards in the transportation sector to 57.7 miles per gallon in 2040. Partial projection tables in Appendix D. | p. 25 | p. 218 |
| Electricity: Low Nuclear | Assumes that all nuclear plants are limited to a 60-year life (45 gigawatts of retirements), uprates are limited to the 1.3 gigawatts that have been reported to EIA, and planned additions are the same as in the Reference case. Partial projection tables in Appendix D. | p. 46 | p. 219 |
| Electricity: High Nuclear | Assumes that all nuclear plants are life-extended beyond 60 years (except for one announced retirement), and uprates are the same as in the Reference case. New plants include those under construction and plants that have a scheduled U.S. Nuclear Regulatory Commission (NRC) or Atomic Safety and Licensing Board hearing. Partial projection tables in Appendix D. | p. 47 | p. 220 |
| Electricity: Small Modular Reactor | Assumes that the characteristics of the new advanced nuclear technology are based on a small modular design rather than the AP1000. Partial projection tables in Appendix D. | p. 47 | p. 220 |
| Renewable Fuels: Low Renewable Technology Cost | Costs for new nonhydropower renewable generating technologies are 20 percent lower than Reference case levels through 2040. Capital costs for new BTL technologies and biodiesel production technologies are reduced by 20 percent relative to the Reference case through 2040. Partial projection tables in Appendix D. | p. 193 | p. 218 |

**Table E1. Summary of the *AEO2013* cases (continued)**

| Case name | Description | Reference in text | Reference in Appendix E |
|---|---|---|---|
| Oil and Gas: Low Oil and Gas Resource | Estimated ultimate recovery (EUR) per shale gas, tight gas, and tight oil well is 50 percent lower than in the Reference case. Partial projection tables in Appendix D. | p. 33 | p. 220 |
| Oil and Gas: High Oil and Gas Resource | Shale gas, tight gas, and tight oil well EURs are 100 percent higher than in the Reference case, and the maximum well spacing is assumed to be 40 acres. Also includes kerogen development, tight oil resources in Alaska, and 50 percent higher undiscovered resources in lower 48 offshore and Alaska than in the Reference case. Partial projection tables in Appendix D. | p. 33 | p. 220 |
| Liquids Market: Low/No Net Imports | Uses *AEO2013* Reference case oil price, with assumed greater improvement in vehicle efficiency and lower vehicle technology costs; post-2025 increase in CAFE standards by 1.4 percent through 2040; lower vehicle miles traveled (VMT); expanded market availability of LNG/CNG in heavy-duty trucks, rail, and marine; higher GTL market penetration; optimistic battery case (*AEO2012*) assumptions for electric drivetrain vehicle costs; and greater availability of domestic petroleum supply (consistent with the High Oil and Gas Resource case). Also assumes increased market penetration of biomass pyrolysis oils, CTL, and BTL production. Also, initial assumptions associated with E85 availability and maximum penetration of E15 are set to be more optimistic. Partial projection tables in Appendix D. | p. 33 | p. 221 |
| Liquids Market: High Net Imports | Uses *AEO2013* Reference case oil price, with assumed lower improvement in vehicle efficiency (driven by limits on technology improvement and non-enforcement of CAFE standards), higher VMT, no change in LNG/CNG market availability, no change in GTL penetration, no change in biofuel market penetration from the Reference case, and lower availability of domestic petroleum supply (consistent with the Low Oil and Gas Resource case). Partial projection tables in Appendix D. | p. 33 | p. 221 |
| Coal: Low Coal Cost | Regional productivity growth rates for coal mining are approximately 2.5 percent per year higher than in the Reference case, and coal mining wages, mine equipment, and coal transportation rates are lower than in the Reference case, falling to about 25 percent below the Reference case in 2040. Partial projection tables in Appendix D. | p. 40 | p. 221 |
| Coal: High Coal Cost | Regional productivity growth rates for coal mining are approximately 2.5 percent per year lower than in the Reference case, and coal mining wages, mine equipment, and coal transportation rates are higher than in the Reference case, ranging between 25 and 32 percent above the Reference case in 2040. Partial projection tables in Appendix D. | p. 40 | p. 221 |
| Integrated 2012 Demand Technology | Referred to in the text as "2012 Demand Technology." Assumes that future equipment purchases in the residential and commercial sectors are based only on the range of equipment available in 2012. Building shell efficiency is held constant at 2012 levels. Energy efficiency of new industrial plant and equipment is held constant at the 2013 level over the projection period. Partial projection tables in Appendix D. | p. 61 | p. 217 |
| Integrated Best Available Demand Technology | Referred to in the text as "Best Available Demand Technology." Assumes that all future equipment purchases in the residential and commercial sectors are made from a menu of technologies that includes only the most efficient models available in a particular year, regardless of cost. Residential building shells for new construction are built to the most efficient specifications after 2012, and existing residential shells have twice the improvement of the Reference case. New and existing commercial building shell efficiencies improve 50 percent more than in the Reference case by 2040. Industrial and transportation sector assumptions are the same as in the Reference case. Partial projection tables in Appendix D. | p. 61 | p. 217 |

**Table E1. Summary of the *AEO2013* cases (continued)**

| Case name | Description | Reference in text | Reference in Appendix E |
|---|---|---|---|
| Integrated High Demand Technology | Referred to in the text as High Demand Technology. Assumes earlier availability, lower costs, and higher efficiencies for more advanced residential and commercial equipment. For new residential construction, building shell efficiencies are assumed to meet ENERGY STAR requirements after 2016. Existing residential shell exhibits 50 percent more improvement than in the Reference case after 2012. New and existing commercial building shells are assumed to improve 25 percent more than in the Reference case by 2040. For the industrial sector, assumes earlier availability, lower costs, and higher efficiency for more advanced equipment and a more rapid rate of improvement in the recovery of biomass byproducts from industrial processes. In the transportation sector, the characteristics of conventional and alternative-fuel LDVs reflect more optimistic assumptions about incremental improvements in fuel economy and costs. Freight trucks are assumed to see more rapid improvement in fuel efficiency for engine and emissions control technologies. More optimistic assumptions for fuel efficiency improvements are also made for the air, rail, and shipping sectors. Partial projection tables in Appendix D. | p. 61 | p. 217 |
| No GHG Concern | No GHG emissions reduction policy is enacted, and market investment decisions are not altered in anticipation of such a policy. Partial projection tables in Appendix D. | p. 87 | p. 222 |
| GHG10 | Applies a price for $CO_2$ emissions throughout the economy, starting at $10 per metric ton in 2014 and rising by 5 percent per year through 2040. Partial projection tables in Appendix D. | p. 86 | p. 222 |
| GHG15 | Applies a price for $CO_2$ emissions throughout the economy, starting at $15 per metric ton in 2014 and rising by 5 percent per year through 2040. Partial projection tables in Appendix D. | p. 86 | p. 222 |
| GHG25 | Applies a price for $CO_2$ emissions throughout the economy, starting at $25 per metric ton in 2014 and rising by 5 percent per year through 2040. Partial projection tables in Appendix D. | p. 86 | p. 222 |
| GHG10 and Low Gas Prices | Combines GHG10 and High Oil and Gas Resource cases. Partial projection tables in Appendix D. | p. 89 | p. 222 |
| GHG15 and Low Gas Prices | Combines GHG15 and High Oil and Gas Resource cases. Partial projection tables in Appendix D. | p. 89 | p. 222 |
| GHG25 and Low Gas Prices | Combines GHG25 and High Oil and Gas Resource cases. Partial projection tables in Appendix D. | p. 89 | p. 222 |

## Buildings sector cases

In addition to the *AEO2013* Reference case, three technology-focused cases using the Demand Modules of NEMS were developed to examine the effects of changes in technology.

Residential sector assumptions for the technology-focused cases are as follows:

- The Integrated 2012 Demand Technology case assumes that all future residential equipment purchases are limited to the range of equipment available in 2012. Existing building shell efficiencies are assumed to be fixed at 2012 levels (no further improvements). For new construction, building shell technology options are constrained to those available in 2012.
- The Integrated High Demand Technology case assumes that residential advanced equipment is available earlier, at lower costs, and/or at higher efficiencies [*155*]. Existing building shell efficiencies exhibit 50 percent more improvement than in the Reference case after 2012. 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 Integrated Best Available Demand Technology case assumes that all future residential equipment purchases are made from a menu of technologies that includes only the most efficient models available in a particular year for each technology class, regardless of cost. Existing building shell efficiencies have twice the improvement of the Reference case after 2012. For new construction, building shell efficiencies are assumed to meet the criteria for the most efficient components after 2012. Consumers evaluate investments in energy efficiency at a 7-percent real discount rate.

Commercial sector assumptions for the technology-focused cases are as follows:

- The Integrated 2012 Demand Technology case assumes that all future commercial equipment purchases are limited to the range of equipment available in 2012. Building shell efficiencies are assumed to be fixed at 2012 levels.

- The Integrated High Demand Technology case assumes that commercial advanced equipment is available earlier, at lower costs, and/or with higher efficiencies than in the Reference case. Energy efficiency investments are evaluated at a 7-percent real discount rate. For new and existing buildings in 2040, building shell efficiencies are assumed to show 25 percent more improvement than in the Reference case.
- The Integrated Best Available Demand Technology case assumes that all future commercial equipment purchases are made from a menu of technologies that includes only the most efficient models available in a particular year for each technology class, regardless of cost. Energy efficiency investments are evaluated at a 7-percent real discount rate. For new and existing buildings in 2040, building shell efficiencies are assumed to show 50 percent more improvement than in the Reference case.

The Residential and Commercial Demand Modules of NEMS were also used to complete the Low Renewable Technology Cost case, which is discussed in more detail below, in the renewable fuels cases section. In combination with assumptions for electricity generation from renewable fuels in the electric power sector and industrial sector, this sensitivity case analyzes 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 for capital cost estimates are 20 percent below Reference case assumptions from 2013 through 2040.

The No Sunset and Extended Policies cases described below in the cross-cutting integrated cases discussion also include assumptions in the Residential and Commercial Demand Modules of NEMS. The Extended Policies case builds on the No Sunset case and adds multiple rounds of appliance standards and building codes as described below.

- The No Sunset case assumes that selected federal policies with sunset provisions will be extended indefinitely rather than allowed to sunset as the law currently prescribes. For the residential sector, these extensions include personal tax credits for PV installations, solar water heaters, small wind turbines, and geothermal heat pumps. For the commercial sector, business ITCs for PV installations, solar water heaters, small wind turbines, geothermal heat pumps, and CHP are extended to the end of the projection. The business tax credit for solar technologies remains at the current 30-percent level without reverting to 10 percent as scheduled. On January 1, 2013, the law was modified to reinstate tax credits for energy-efficient homes and selected residential appliances. The tax credits that had expired on December 31, 2011, are now extended through December 31, 2013. This change was made after the completion of *AEO2013* and is not reflected in the analysis.
- The Extended Policies case includes updates to federal appliance standards, as prescribed by the timeline in DOE's multi-year plan, and introduces new standards for products currently not covered by DOE. Efficiency levels for the updated residential appliance standards are based on current ENERGY STAR guidelines. End-use technologies eligible for No Sunset incentives are not subject to new standards. Efficiency levels for updated commercial equipment standards are based on the technology menu from the *AEO2013* Reference case and purchasing specifications for federal agencies designated by the Federal Energy Management Program. The case also adds national building codes to reach a 30-percent improvement in 2020 relative to the 2006 International Energy Conservation Code for residential households and to American Society of Heating, Refrigerating, and Air-Conditioning Engineers Standard 90.1-2004 for commercial buildings, with additional rounds of improved codes in 2023 and 2026.

### Industrial sector cases

In addition to the *AEO2013* Reference case, two technology-focused cases using the IDM of NEMS were developed that examine the effects of less rapid and more rapid technology change and adoption. The energy intensity changes discussed in this section exclude the refining industry, which is modeled separately from the IDM in the LFMM. Different assumptions for the IDM were also used as part of the Integrated Low Renewable Technology Cost case, No Sunset case, and Extended Policies case, but each is structured on a set of the initial industrial assumptions used for the Integrated 2012 Demand Technology case and Integrated High Demand Technology case. The IDM assumptions for the Industrial High Resource case and the Industrial Low Resource case are based only on the Integrated High Demand Technology case. For the industrial sector, assumptions for the two technology-focused cases are as follows:

- For the Integrated 2012 Demand Technology case, the energy efficiency of new industrial plant and equipment is held constant at the 2013 level over the projection period. Changes in aggregate energy intensity may result both from changing equipment and production efficiency and from changing composition of output within an individual industry. Because all *AEO2013* side cases are integrated runs, potential feedback effects from energy market interactions are captured. Hence, the level and composition of overall industrial output varies from the Reference case, and any change in energy intensity in the two technology side cases is attributable to process and efficiency changes and increased use of CHP, as well as changes in the level and composition of overall industrial output.
- For the Integrated High Demand Technology case, the IDM assumes earlier availability, lower costs, and higher efficiency for more advanced equipment [*156*] and a more rapid rate of improvement in the recovery of biomass byproducts from industrial processes—i.e., 0.7 percent per year, as compared with 0.4 percent per year in the Reference case. The same assumption is

incorporated in the 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 Demand Technology case, it is based on the expectation of higher recovery rates and substantially increased use of CHP in that case. Due to integration with other NEMS modules, potential feedback effects from energy market interactions are captured.

The No Sunset and Extended Policies cases described below in the cross-cutting integrated cases discussion also include assumptions in the IDM of NEMS. The Extended Policies case builds on the No Sunset case and modifies selected industrial assumptions as follows:

- The No Sunset case and Extended Policies case include an assumption for CHP that extends the existing ITC for industrial CHP through the end of the projection period. Additionally, the Extended Policies case includes an increase in the capacity limitations on the ITC by increasing the cap on CHP equipment from 15 megawatts to 25 megawatts and eliminating the system-wide cap of 50 megawatts. These assumptions are based on the current proposals in H.R. 2750 and H.R. 2784 of the 112th Congress. The decline in natural gas prices related to increased domestics shale gas production is addressed in two cases, which assumer higher and lower shale gas resources than projected in the Reference case.

## Transportation sector cases

In addition to the *AEO2013* Reference case, the NEMS Transportation Demand Module was used as part of four *AEO2013* side cases.

The Transportation Demand Module was used to examine the effects of advanced technology costs and efficiency improvement for technology adoption and vehicle fuel economy as part of the Integrated High Demand Technology case [*157*]. For the Integrated High Demand 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 Integrated High Demand Technology case assumes more rapid incremental improvement in fuel efficiency and lower costs for engine and emissions control technologies. More optimistic assumptions for fuel efficiency improvements are also made for the air, rail, and shipping sectors.

The Transportation Demand Module was used to examine the effects of an extension to the LDV GHG Emissions and CAFE Standards beyond 2025 as part of the Extended Policies case. The joint EPA and NHTSA CAFE Standards were increased after 2025, at an average annual rate of 1.4 percent through 2040, for a combined average LDV fuel economy of 57.7 miles per gallon in 2040.

Assumptions in the NEMS Transportation Demand Module were also modified for the Low/No Net Imports case. This case examines the effects of decreased VMT on the LDV transportation sector. It includes more optimistic assumptions about improvements in LDV fuel economy and reductions in LDV technology costs, lower VMT, an extension of the LDV CAFE standards beyond 2025 at an average annual rate of 1.4 percent through 2040, expanded market availability of LNG/CNG fuels for heavy-duty trucks, rail, and marine. It uses the assumptions from the optimistic battery case (*AEO2012*) for electric vehicle battery and drivetrain costs.

In the High Net Imports case, the assumptions used in the NEMS Transportation Demand Module were adjusted to incorporate a more pessimistic outlook. This case assumes lower improvement in LDV fuel economy (driven by limits on technology improvement and non-enforcement of CAFE standards), higher VMT, no change in LNG/CNG market availability, and no change in biofuel market penetration from the Reference case.

## Electricity sector cases

In addition to the Reference case, several integrated cases with alternative electric power assumptions were developed to support discussions in the "Issues in focus" section of *AEO2013*. Three alternative cases were run for nuclear power plants, to address uncertainties about the operating lives of existing reactors and the potential for new nuclear capacity and capacity uprates at existing plants. These cases are discussed in the "Issues in focus" article, "Nuclear power through 2040."

### Nuclear cases

- The Low Nuclear case assumes that reactors will not receive a second license renewal, so that all existing nuclear plants are retired within 60 years of operation. The reported retirement at Oyster Creek occurs as currently planned, at the end of 2019. Also, Kewaunee is retired at the end of 2014, based on an announcement by Dominion Resources in late 2012 stating their intention to retire the unit in the next few years. Additionally, two units that are currently out of service are assumed to be permanently shut down in the Low Nuclear case. San Onofre 2 and Crystal River 3 currently are not operating, but they are assumed to be returned to service in 2015 in the Reference case. In the Low Nuclear case they are retired in 2013. 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 would occur for most plants that reach 60 years of operation before 2040. The Low Nuclear case was run to analyze the impact of additional nuclear retirements. In this case, no plants receive license extensions beyond 60 years, and 45 gigawatts of nuclear capacity is assumed to be retired by 2040. The Low Nuclear case assumes that no new nuclear capacity will be added throughout the projection, excluding capacity already planned or under construction. It also assumes that only those capacity uprates already reported to EIA (1.3 gigawatts) will be completed. The Reference case assumes additional uprates based on NRC surveys and industry reports.

- The High Nuclear case assumes that all existing nuclear units will receive a second license renewal and operate beyond 60 years (excluding one announced retirement). In the Reference case, beyond the announced retirement of Oyster Creek, an additional 6.5 gigawatts of nuclear capacity is assumed to be retired through 2040, reflecting uncertainty about the impacts and/or costs of future aging. The High Nuclear case was run to provide a more optimistic outlook, with all licenses renewed and all plants continuing to operate economically beyond 60 years. The High Nuclear case also assumes that additional planned nuclear capacity is completed, based on combined license applications issued by the NRC and where an NRC or Atomic Safety and Licensing Board hearing has been scheduled. The Reference case assumes that 5.5 gigawatts of planned capacity are added, compared with 13.3 gigawatts of planned capacity additions in the High Nuclear case.
- The Small Modular Reactor case assumes that new advanced nuclear plants built after 2025 will be based on a smaller modular design rather than the larger AP1000 design used in the Reference case. The overnight costs are assumed to be the same as in the Reference case, but the construction lead time is reduced from 6 years to 3 years for the smaller design. The fixed operating and maintenance costs are assumed to be higher for the smaller design. To account for the time necessary for design certification, the first available online date for the small reactors is assumed to be 2025.

**Renewable generation cases**

In addition to the *AEO2013* Reference case, EIA developed a case with alternative assumptions about renewable generation technologies and policies to examine the effects of more aggressive improvement in the costs of renewable technologies.

- In the Low Renewable Technology Cost case, the levelized costs of new nonhydropower renewable generating technologies are assumed to be 20 percent below Reference case assumptions from 2013 through 2040. In general, lower costs are represented by reducing the capital costs of new plant construction. Biomass fuel supplies also are assumed to be 20 percent less expensive than in the Reference case for the same resource quantities. 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.
- In the No Sunset case and the Extended Policies case, expiring federal tax credits targeting renewable electricity are assumed to be permanently extended. This applies to the PTC, which is a tax credit of 2.2 cents per kilowatthour available for the first 10 years of production by new generators using wind, geothermal, and certain biomass fuels, or a tax credit of 1.1 cents per kilowatthour available for the first 10 years of production by new generators using geothermal energy, certain hydroelectric technologies, and biomass fuels not eligible for the full credit of 2.2 cents per kilowatthour. This tax credit had been scheduled to expire on December 31, 2012 for wind and 1 year later for other eligible technologies. The same schedule applies to the 30-percent ITC, which is available to new solar installations through December 31, 2016, and may also be claimed in lieu of the PTC for eligible technologies, expiring concurrently with the PTC (described above). On January 1, 2013, the law was modified to extend the expiration date for wind by one full year and to allow new plants using any eligible technology to qualify if they were under construction by the deadline—not actually in commercial service by the deadline, as was previously required. However, this change occurred too late to allow for inclusion in this report.

## Oil and gas supply cases

The sensitivity of the *AEO2013* projections to changes in assumptions regarding technically recoverable domestic crude oil and natural gas resources is examined in two cases. These cases do not represent a confidence interval for future domestic oil and natural gas supply but rather provide a framework to examine the impact of higher and lower domestic supply on energy demand, imports, and prices. Assumptions associated with these cases are described below.

- In the Low Oil and Gas Resource case, the EUR per tight oil, tight gas, and shale gas well is assumed to be 50 percent lower than in the Reference case, increasing the per-unit cost of developing the resource. The total unproved technically recoverable resource (TRR) of crude oil is decreased to 168 billion barrels, and the natural gas resource is decreased to 1,500 trillion cubic feet, as compared with unproved resource estimates of 197 billion barrels of crude oil and 2,022 trillion cubic feet of natural gas in the Reference case as of January 1, 2011.
- In the High Oil and Gas Resource case, the resource assumptions are adjusted to give continued increase in domestic crude oil production after 2020, reaching over 10 million barrels per day. This case includes: (1) 100 percent higher EUR per tight oil, tight gas, and shale gas well than in the Reference case and a maximum well spacing of 40 acres, to reflect the possibility that additional layers of low-permeability zones are identified and developed, compared with well spacing that ranges from 20 to 406 acres with an average of 100 acres in the Reference case; (2) kerogen development reaching 135,000 barrels per day in 2025; (3) tight oil development in Alaska increasing the total Alaska TRR by 1.9 billion barrels; and (4) 50 percent higher technically recoverable undiscovered resources in Alaska and the offshore lower 48 states than in the Reference case. Additionally, a few offshore Alaska fields are assumed to be discovered and thus developed earlier than in the Reference case. Given the higher natural gas resource in this case, the maximum penetration rate for GTL was increased to 10 percent per year, compared to a rate of 5 percent per year in the Reference case.

## Liquids market cases

Two sensitivity cases have been designed to analyze petroleum imports in the United States. Assumptions associated with these cases are described below.

- In the Low/No Net Imports case, changes were made to various NEMS modeling assumptions that, in comparison with the *AEO2013* reference case, resulted in higher domestic production of crude oil and natural gas, lower domestic liquid fuels demand, and higher domestic production of nonpetroleum liquids. The methodology used to achieve higher domestic crude production is the same as that used in the High Oil and Gas Resource case (described in the "Oil and gas supply cases" section above). Domestic liquid fuels demand was reduced by changes made in the Transportation Demand Module. As described in the "Transportation sector cases" section, this included the use of more optimistic assumptions about improvements in LDV fuel economy and reductions in LDV technology costs; lower VMT due to changes in consumer behavior; an extension of the LDV CAFE standards beyond 2025 at an average annual rate of 1.4 percent through 2040; expanded market availability of LNG/CNG fuels for heavy-duty trucks, rail, and marine; and use of assumptions from the optimistic battery case (*AEO2012*) for electric vehicle battery and drivetrain costs. Within the LFMM, the assumption for market penetration of biomass pyrolysis oils, CTL, and BTL production was more optimistic. Also, initial assumptions associated with E85 availability and maximum penetration of E15 were set to be more optimistic, such that E85 availability was nearly three times the Reference case level in 2040, and E15 penetration was about 15 percent higher by 2040.
- In the High Net Imports case, changes were made in two NEMS modules to reduce domestic crude oil production and increase domestic demand for liquid fuels, as compared with the Reference case. The methodology used to achieve lower domestic crude production is the same as that used in the Low Oil and Gas Resource case described above. An increase in domestic liquids fuels demand was achieved by assuming lower improvement in vehicle efficiency (driven by limits on technology improvement and non-enforcement of CAFE standards and resulting in a lower number of alternatively fueled vehicles, including hybrid, plug-in hybrid, and battery electric vehicles); higher VMT; no change in LNG/CNG market availability; no change in GTL penetration; and no change in biofuel market penetration compared with 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 2013 through 2040. 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 2.5 percent observed since 2000 for mines in Wyoming's Powder River Basin and 2.4 percent for other coal-producing regions. 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 2040. 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 productivity growth rate for Wyoming's Southern Powder River Basin supply curve is increased from -1.6 percent in the Reference case for the years 2013 through 2040 to 0.9 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 2040 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 2040.
- 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 2040 are assumed to be about 32 percent higher than in the Reference case, and coal transportation rates in 2040 are assumed to be 25 percent higher.

Additional data on productivity, wage, mine equipment cost, and coal transportation rate assumptions for the Reference and alternative coal cost cases are shown in Appendix D.

## Cross-cutting integrated cases

A series of cross-cutting integrated cases are used in *AEO2013* to analyze specific cases with broader sectoral impacts. For example, three integrated technology progress cases analyze the impacts of faster and slower technology improvement in the demand sector (partially described in the sector-specific sections above). In addition, seven cases were run with alternative assumptions about expectations of future regulation of GHG emissions.

### Integrated technology cases

In the demand sectors (residential, commercial, industrial, and transportation), technology improvement typically means greater efficiency and/or reduced technology cost. Three alternative demand technology cases—Integrated 2012 Demand Technology, Integrated Best Available Demand Technology, and Integrated High Demand Technology cases—are used in *AEO2013* to examine the potential impacts of variation in the rate of technology improvement in the end-use demand sectors, independent of any offsetting impacts of variations in technology improvement in the supply/conversion sectors. Assumptions for each end-use sector are described in the sector-specific sections above.

**No Sunset case**

In addition to the *AEO2013* Reference case a No Sunset case was run, assuming that selected federal policies with sunset provisions—such as the PTC, ITC, and tax credits for renewable and CHP equipment in the buildings and industrial sectors—will be extended indefinitely rather than allowed to sunset as the law currently prescribes. Specific assumptions for each end-use sector and for renewables are described in the sector-specific sections above.

**Extended Policies case**

In the Extended Policies case, assumptions for tax credit extensions are the same as in the No Sunset case described above. Further, updates to federal appliance efficiency standards are assumed to occur at regular intervals, and new standards for products not currently covered by DOE are assumed to be introduced. Finally, fuel economy standards for LDVs, including both passenger cars and light-duty trucks, are assumed to continue increasing after 2025. Specific assumptions for each end-use sector and for renewables are described in the sector-specific sections above.

**Greenhouse gas cases**

Given concerns about climate change and possible future policy actions to limit GHG emissions, regulators and the investment community are beginning to push energy companies to invest in technologies that are less GHG-intensive. To reflect the market's current reaction to potential future GHG regulation, a 3-percentage-point increase in the cost of capital is assumed for investments in new coal-fired power plants without CCS and for all capital investment projects at existing coal-fired power plants in the Reference case and all other *AEO2013* cases except the No GHG Concern case, GHG10 case, GHG15 case, GHG25 case, GHG10 and Low Gas Prices case, GHG15 and Low Gas Prices case, and GHG25 and Low Gas Prices case. Those assumptions affect cost evaluations for the construction of new capacity but not the actual operating costs when a new plant begins operation.

The seven alternative GHG cases are used to provide a range of potential outcomes, from no concern about future GHG legislation to the imposition of a specific economywide carbon emissions price, as well as an examination of the impact of a combination of specific economywide carbon emissions prices and low natural gas prices. *AEO2013* includes six economywide $CO_2$ price cases, combining three levels of carbon prices with two alternative gas price projections. In the GHG10 case and GHG10 and Low Gas Prices case, the carbon emissions price is set at $10 per metric ton $CO_2$ in 2014. In the GHG15 case and GHG15 and Low Gas Prices case, the carbon emissions price is set at $15 per metric ton $CO_2$ in 2014. In the GHG25 case and GHG25 and Low Gas Prices case, the price is set at $25 per metric ton $CO_2$ in 2014. In all cases the price begins to rise in 2014 at 5 percent per year. The GHG10, GHG15, and GHG25 cases use the Reference case assumptions regarding oil and gas resource availability. The GHG10 and Low Gas Prices case, GHG15 and Low Gas Prices case, and GHG25 and Low Gas Prices case use the assumptions from the High Oil and Gas Resource case, as described above in the "Oil and gas supply" section. The GHG cases are intended to measure the sensitivity of the *AEO2013* projections to a range of implicit or explicit valuations of $CO_2$. At the time *AEO2013* was completed, no legislation including a GHG price was pending; however, the EPA is developing technology-based $CO_2$ standards for new coal-fired power plants. In the GHG cases for *AEO2013*, no assumptions are made with regard to offsets, policies to promote CCS, or specific policies to mitigate impacts in selected sectors.

The No GHG Concern case was run without any adjustment for concern about potential GHG regulations (without the 3-percentage-point increase in the cost of capital). In the No GHG Concern case, the same cost of capital is used to evaluate all new capacity builds, regardless of type.

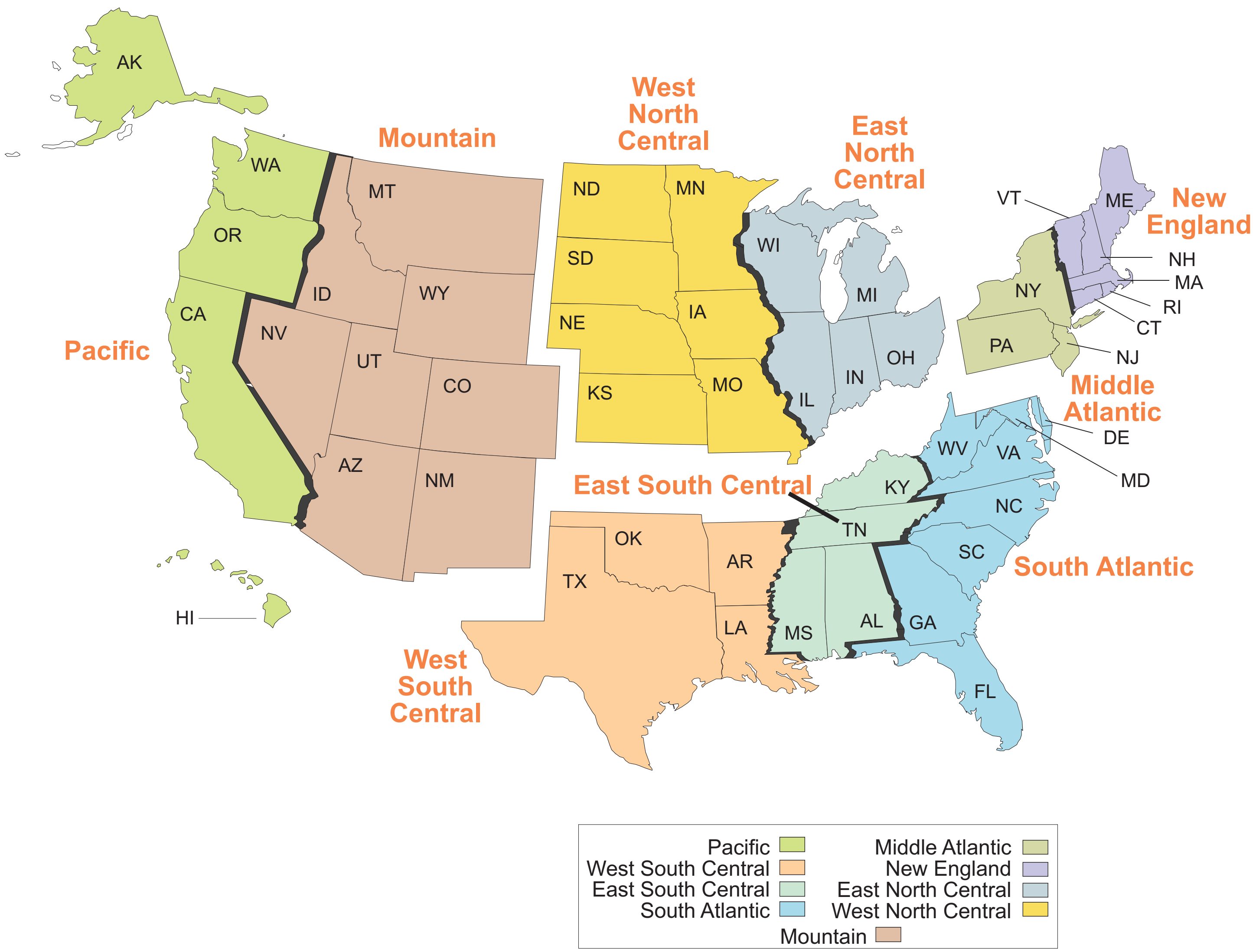
# Endnotes for Appendix E

**Links current as of March 2013**

148. U.S. Energy Information Administration, *The National Energy Modeling System: An Overview 2009*, DOE/EIA-0581(2009) (Washington, DC: October 2009), website www.eia.gov/oiaf/aeo/overview.
149. U.S. Energy Information Administration, *Annual Energy Review 2011*, DOE/EIA-0384(2011) (Washington, DC: September 2012), website www.eia.gov/aer.
150. U.S. Energy Information Administration, *Short-Term Energy Outlook September 2012* (Washington, DC: September 2012), website www.eia.gov/forecasts/steo/archives/Sep12.pdf. Portions of the preliminary information were also used to initialize the NEMS Liquids Fuels Market Module projection.
151. U.S. Energy Information Administration, "Short-Term Energy Outlook" (Washington, DC: January 2013), website www.eia.gov/forecasts/steo/outlook.cfm.
152. U.S. Energy Information Administration, *Assumptions to the Annual Energy Outlook 2013*, DOE/EIA-0554(2013) (Washington, DC: April 2013), website www.eia.gov/forecasts/aeo/assumptions.
153. Alternative other liquids technologies include all biofuels technologies plus CTL and GTL.
154. U.S. Energy Information Administration, *Assumptions to the Annual Energy Outlook 2013*, DOE/EIA-0554(2013) (Washington, DC: April 2013), website www.eia.gov/forecasts/aeo/assumptions.
155. High technology assumptions for the buildings sector are based on U.S. Energy Information Administration, *EIA—Technology Forecast Updates—Residential and Commercial Building Technologies—Advanced Case* (Navigant Consulting, Inc. with SAIC, September 2011), and *EIA—Technology Forecast Updates—Residential and Commercial Building Technologies—Advanced Case* (Navigant Consulting, Inc. with SAIC, November 2012).
156. These assumptions are based in part on U.S. Energy Information Administration, *Industrial Technology and Data Analysis Supporting the NEMS Industrial Model* (FOCIS Associates, October 2005).
157. 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).

# Regional Maps

## Figure F1. United States Census Divisions




Source: U.S. Energy Information Administration, Office of Energy Analysis.

**Figure F1. United States Census Divisions (continued)**

**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**

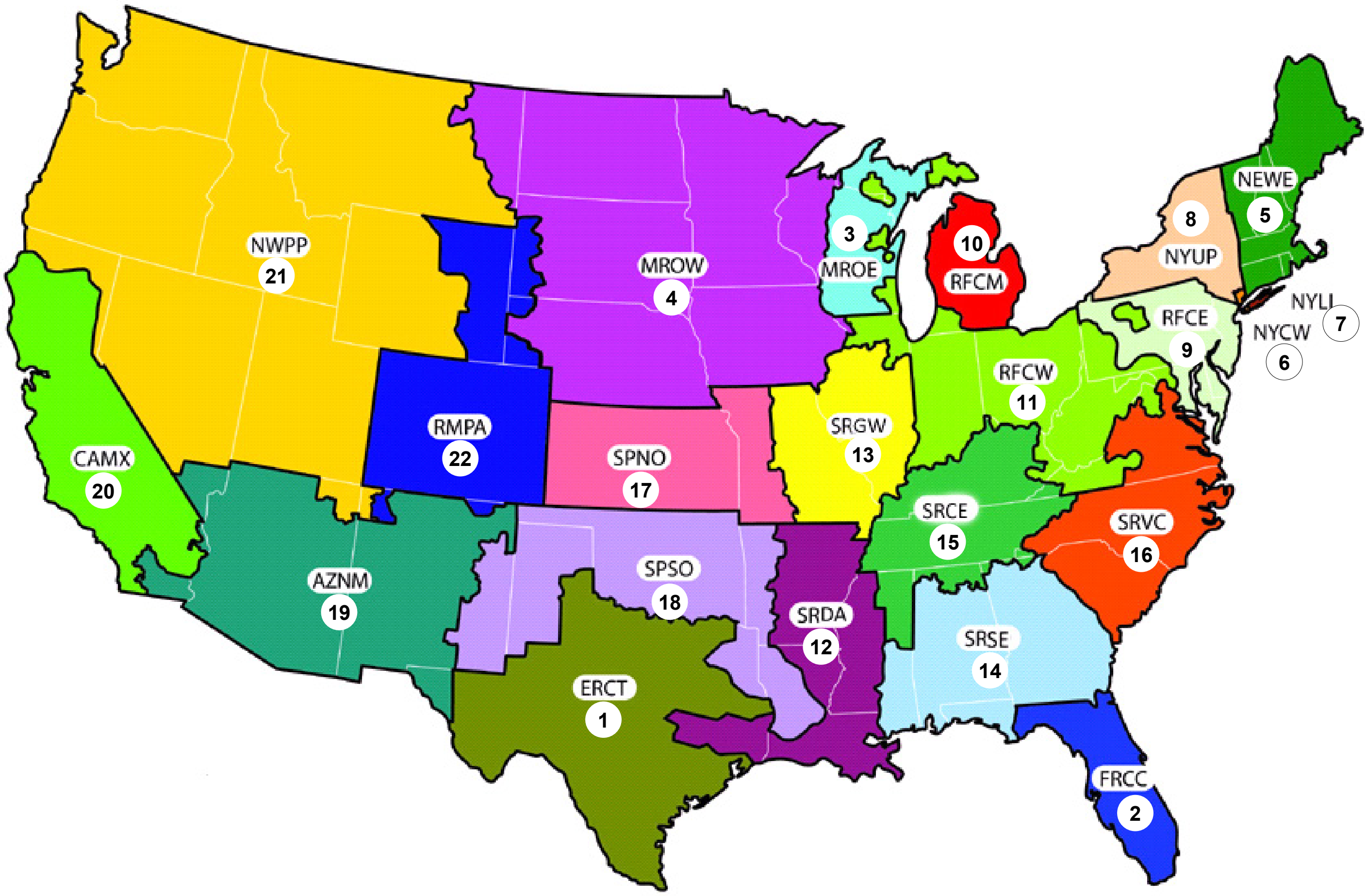
Arizona
Colorado
Idaho
Montana
Nevada
New Mexico
Utah
Wyoming

**Division 9**
**Pacific**

Alaska
California
Hawaii
Oregon
Washington

Source: U.S. Energy Information Administration, Office of Energy Analysis.

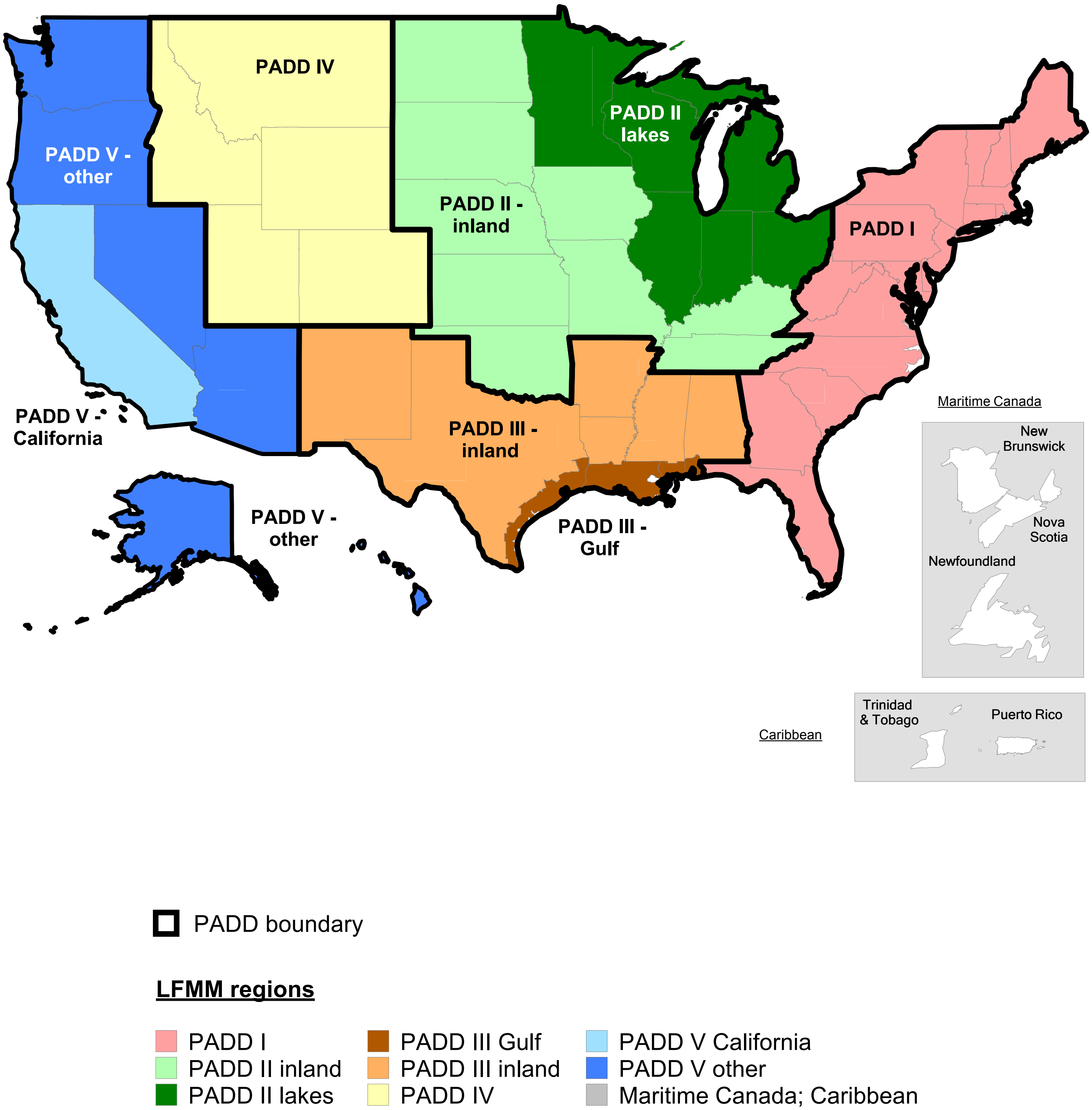
**Figure F2. Electricity market module regions**




| | | | | | |
|---|---|---|---|---|---|
| 1. | ERCT | TRE All | 12. | SRDA | SERC Delta |
| 2. | FRCC | FRCC All | 13. | SRGW | SERC Gateway |
| 3. | MROE | MRO East | 14. | SRSE | SERC Southeastern |
| 4. | MROW | MRO West | 15. | SRCE | SERC Central |
| 5. | NEWE | NPCC New England | 16. | SRVC | SERC VACAR |
| 6. | NYCW | NPCC NYC/Westchester | 17. | SPNO | SPP North |
| 7. | NYLI | NPCC Long Island | 18. | SPSO | SPP South |
| 8. | NYUP | NPCC Upstate NY | 19. | AZNM | WECC Southwest |
| 9. | RFCE | RFC East | 20. | CAMX | WECC California |
| 10. | RFCM | RFC Michigan | 21. | NWPP | WECC Northwest |
| 11. | RFCW | RFC West | 22. | RMPA | WECC Rockies |

Source: U.S. Energy Information Administration, Office of Energy Analysis.

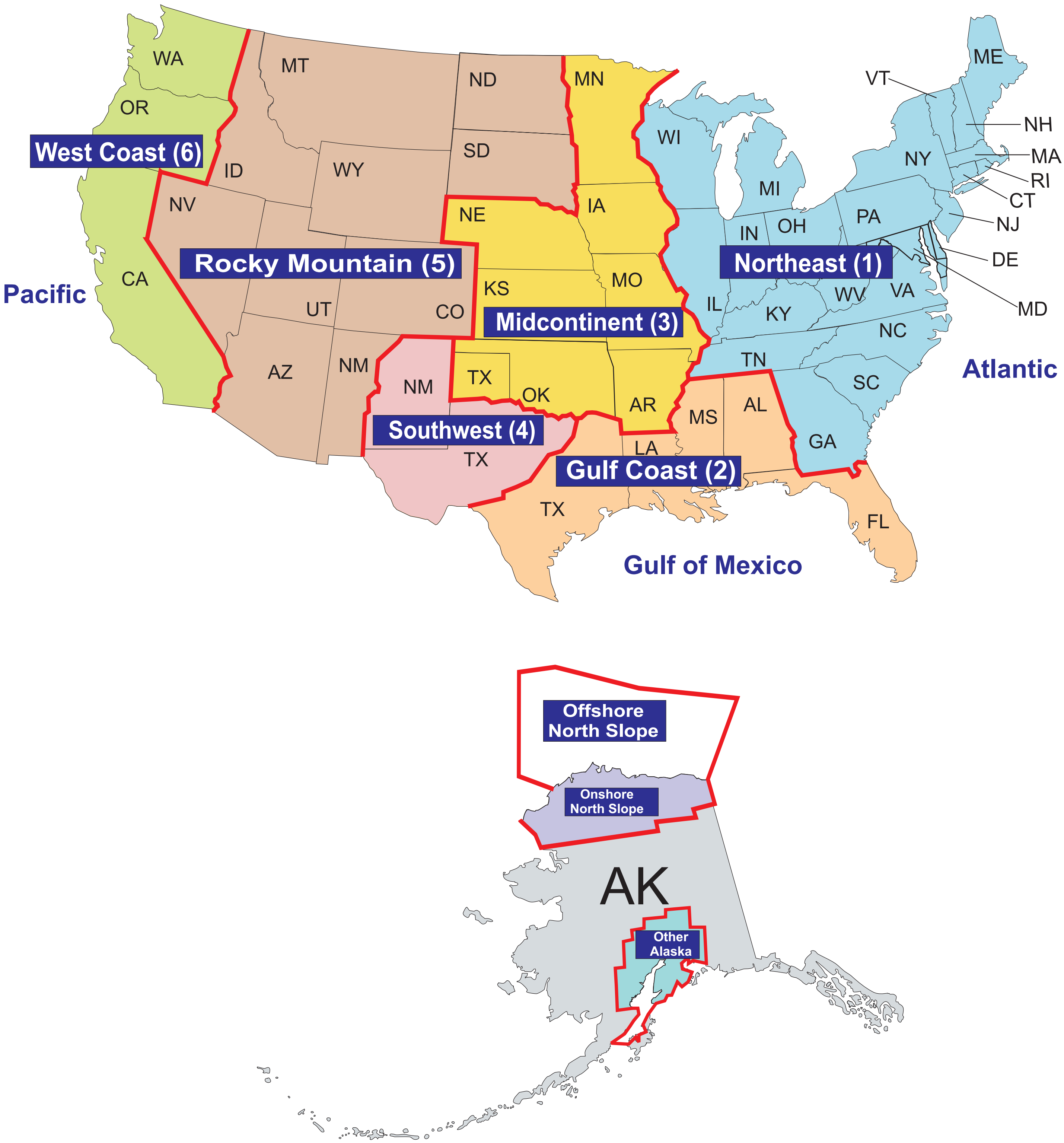
## Figure F3. Liquid fuels market module regions




Source: U.S. Energy Information Administration, Office of Energy Analysis.

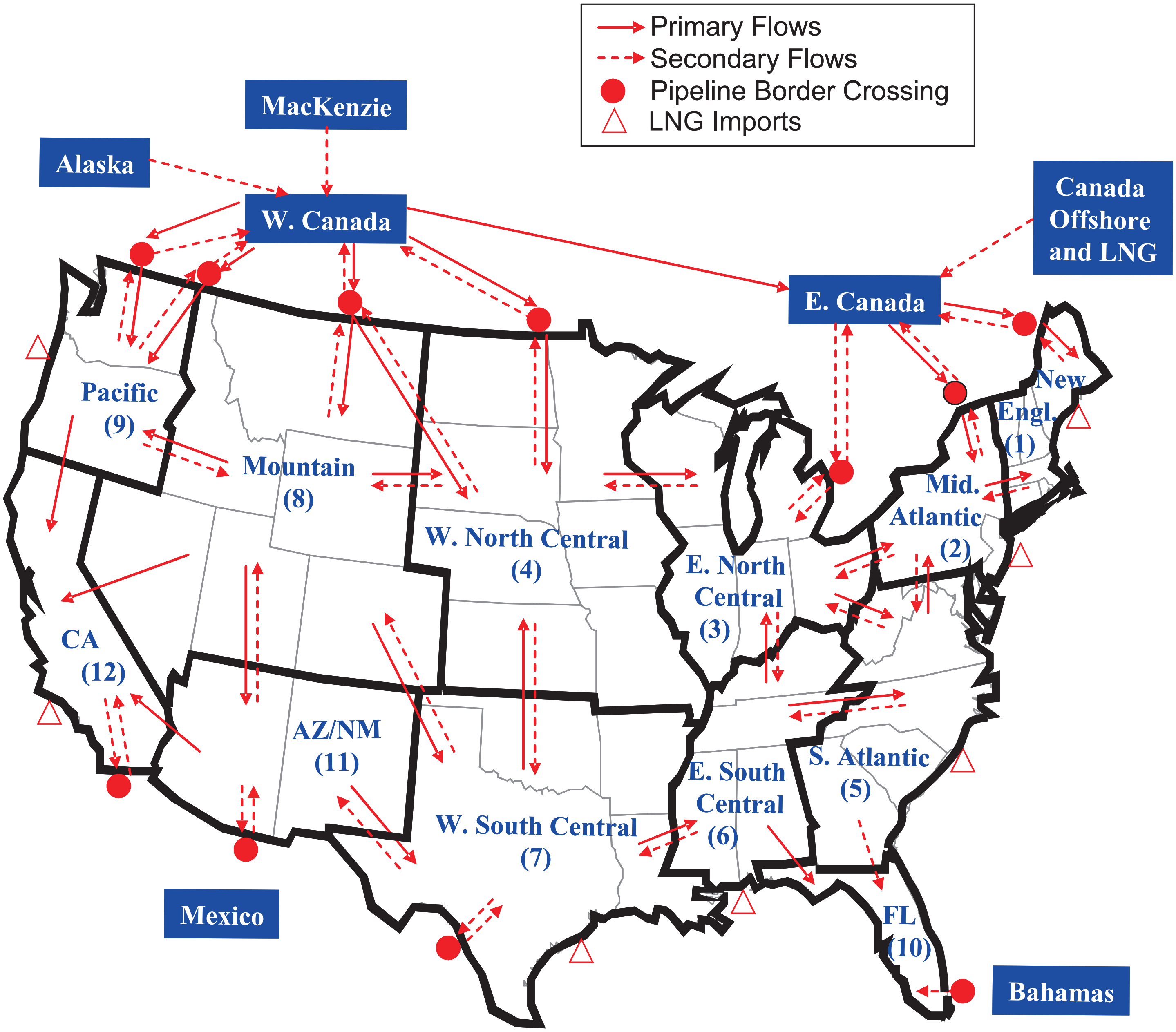
Source

**Figure F4. Oil and gas supply model regions**



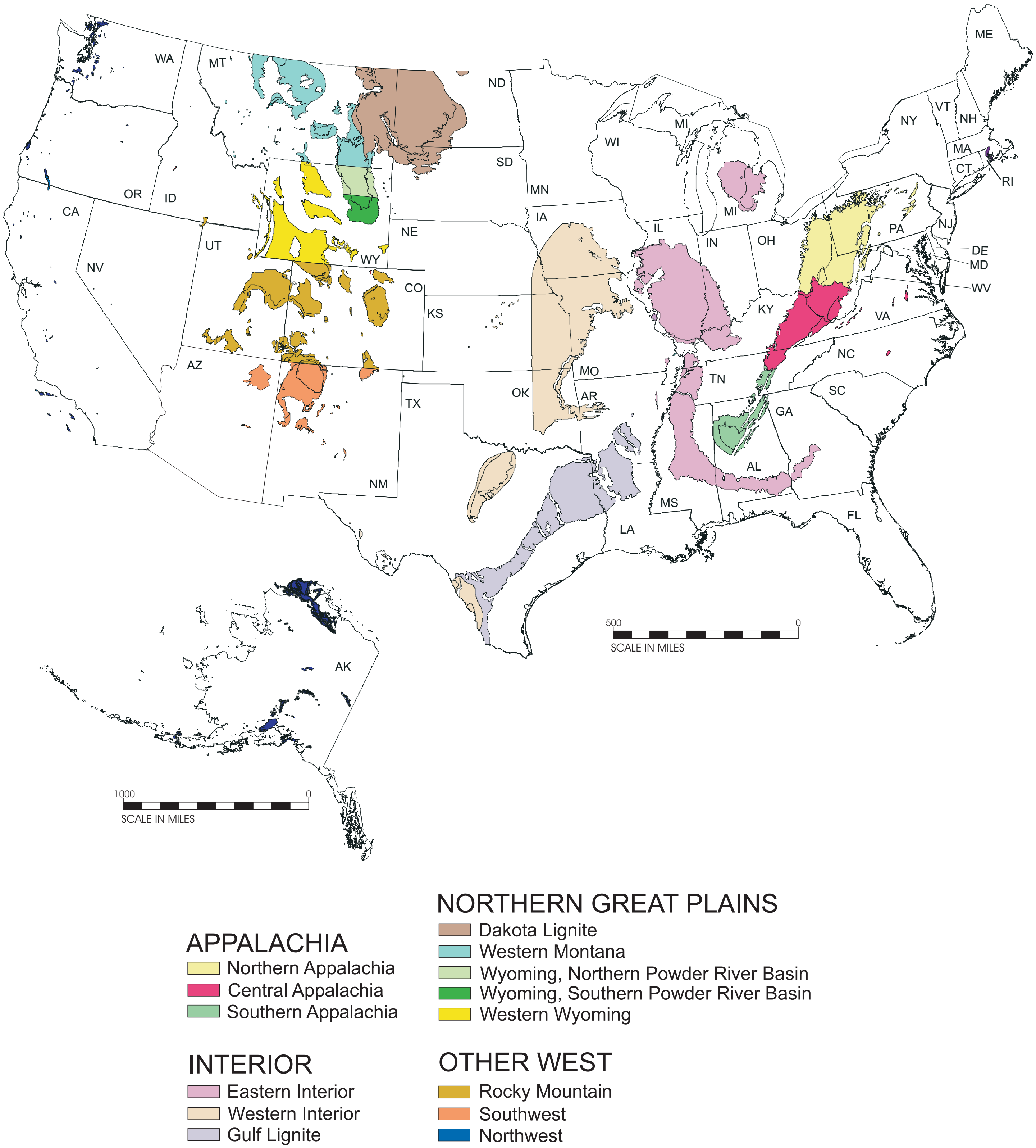

Source: U.S. Energy Information Administration, Office of Energy Analysis.

**Figure F5. Natural gas transmission and distribution model regions**




Source: U.S. Energy Information Administration, Office of Energy Analysis.

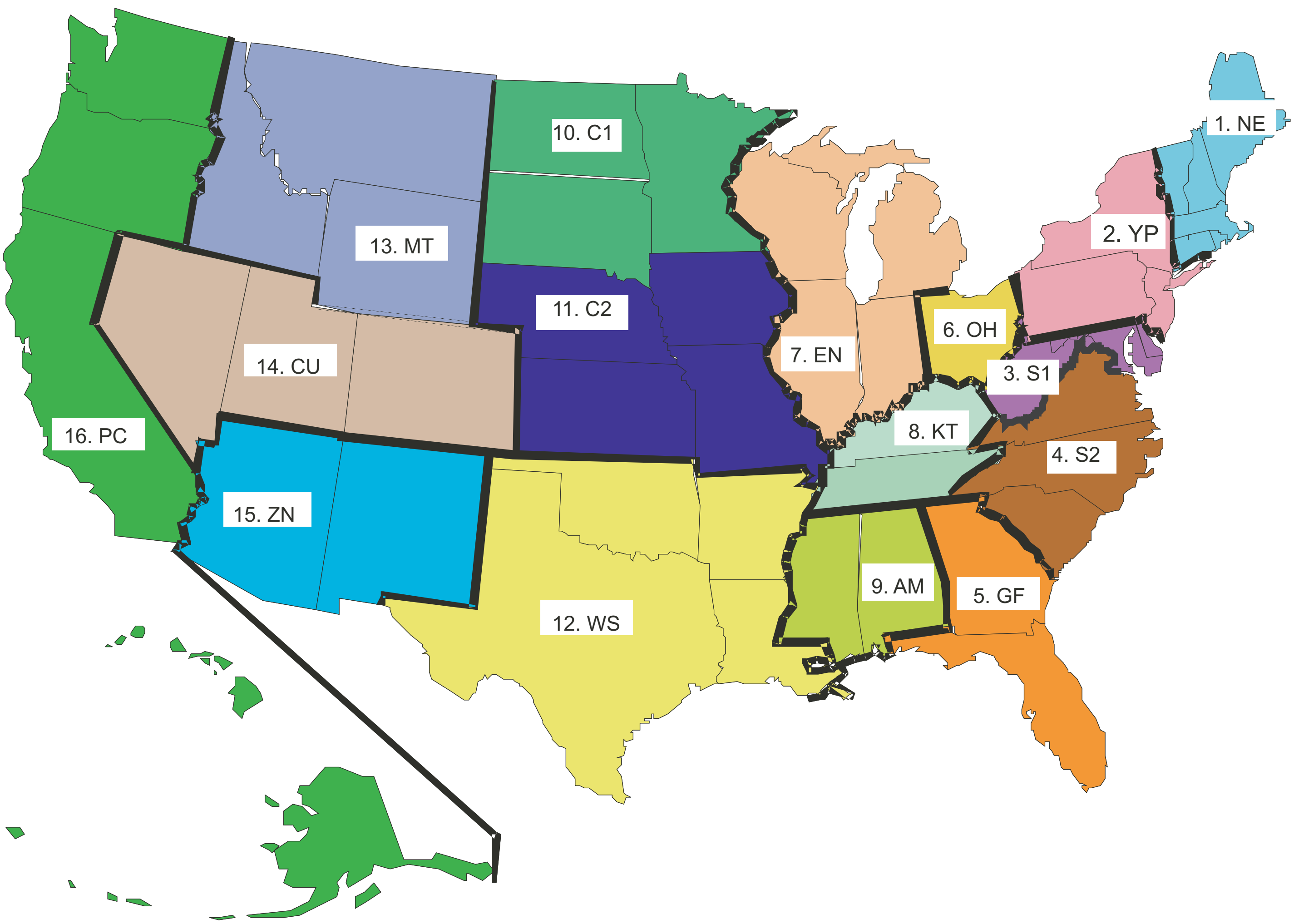
## Figure F6. Coal supply regions






Source: U.S. Energy Information Administration, Office of Energy Analysis.

## 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 Energy Analysis.

Appendix G

# Conversion factors

### Table G1. Heat contents

| Fuel | Units | Approximate heat content |
|---|---|---|
| **Coal**[1] | | |
| Production | million Btu per short ton | 20.136 |
| Consumption | million Btu per short ton | 19.810 |
| Coke plants | million Btu per short ton | 26.304 |
| Industrial | million Btu per short ton | 23.651 |
| Residential and commercial | million Btu per short ton | 20.698 |
| Electric power sector | million Btu per short ton | 19.370 |
| Imports | million Btu per short ton | 25.394 |
| Exports | million Btu per short ton | 25.639 |
| **Coal coke** | million Btu per short ton | 24.800 |
| **Crude oil** | | |
| Production | million Btu per barrel | 5.800 |
| Imports[1] | million Btu per barrel | 5.967 |
| **Petroleum products and other liquids** | | |
| Consumption[1] | million Btu per barrel | 5.353 |
| Motor gasoline[1] | million Btu per barrel | 5.048 |
| Jet fuel | million Btu per barrel | 5.670 |
| Distillate fuel oil[1] | million Btu per barrel | 5.762 |
| Diesel fuel[1] | million Btu per barrel | 5.759 |
| Residual fuel oil | million Btu per barrel | 6.287 |
| Liquefied petroleum gases[1] | million Btu per barrel | 3.577 |
| Kerosene | million Btu per barrel | 5.670 |
| Petrochemical feedstocks[1] | million Btu per barrel | 5.114 |
| Unfinished oils | million Btu per barrel | 6.039 |
| Imports[1] | million Btu per barrel | 5.580 |
| Exports[1] | million Btu per barrel | 5.619 |
| Ethanol | million Btu per barrel | 3.560 |
| Biodiesel | million Btu per barrel | 5.359 |
| **Natural gas plant liquids** | | |
| Production[1] | million Btu per barrel | 3.566 |
| **Natural gas**[1] | | |
| Production, dry | Btu per cubic foot | 1,022 |
| Consumption | Btu per cubic foot | 1,022 |
| End-use sectors | Btu per cubic foot | 1,023 |
| Electric power sector | Btu per cubic foot | 1,021 |
| 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 2011.
Btu = British thermal unit.
Sources: U.S. Energy Information Administration (EIA), *Annual Energy Review 2011*, DOE/EIA-0384(2011) (Washington, DC, September 2012), and EIA, AEO2013 National Energy Modeling System run REF2013.D102312A.