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Annual Energy Outlook 2014

with projections to 2040

Independent Statistics & Analysis

U.S. Energy Information Administration

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AEO2014 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 AEO2014 during 2014.

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Preface

The *Annual Energy Outlook 2014* (AEO2014), prepared by the U.S. Energy Information Administration (EIA), presents long-term annual projections of energy supply, demand, and prices focused on the U.S. through 2040, based on results from EIA's National Energy Modeling System (NEMS). NEMS enables EIA to make projections under alternative, internally-consistent sets of assumptions, the results of which are presented as cases. The analysis in AEO2014 focuses on five primary cases: 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. EIA published an Early Release version of the AEO2014 Reference case in December 2013.

The report begins with an Executive Summary that highlights key implications of the projections, followed by a Legislation and Regulations section that discusses how recently enacted federal and state legislation and regulations were incorporated in AEO2014, such as: the revised carbon dioxide emissions standards and banking provisions announced by the Regional Greenhouse Gas Initiative in February 2013 [*1*]; updated Renewable Fuel Standard target volumes to reflect actions by the U.S. Environmental Protection Agency to lower the target volume of cellulosic biofuel; and incorporation of modifications to existing state renewable portfolio standards or similar laws since the *Annual Energy Outlook 2013* was released. The Legislation and Regulations section also discusses selected legislative and regulatory issues could have major implications for energy markets and may be enacted in the near future.

The Issues in Focus section contains articles on selected energy topics, including a discussion of the results of two cases based on different assumptions about the future course of existing energy policies: one assumes the elimination of sunset provisions for various energy tax credits that are scheduled to expire under current law; the other assumes—in addition to the elimination of sunset provisions on various tax credits—the extension or expansion of three existing policies: corporate average fuel economy (CAFE) standards, appliance standards, and building code improvements. Other discussions include:

- U.S. tight oil production trends and supply projections based on alternative assumptions and a methodology using well-level data aggregated to the county level
- Potential of liquefied natural gas as a freight locomotive fuel
- Impacts of demographic issues and travel behavior on light-duty vehicle energy demand
- Effects of lower natural gas prices on projected industrial production
- Implications of accelerated power plant retirements
- Renewable electricity projections under alternative assumptions in AEO2014
- Implications of low electricity demand growth.

The Market Trends section summarizes the AEO2014 projections for energy markets by end-use market sector or energy supply source. In some instances, this section also uses alternative cases to illustrate a range of potential outcomes under difference circumstances, highlighting the uncertainty associated with the projections. Complete tables for the five primary cases are provided in Appendixes A through C, and major results from many of the other alternative cases are provided in Appendix D. Complete tables for all the alternative cases are available in a table browser on EIA's website, at http://www.eia.gov/oiaf/aeo/tablebrowser.

AEO2014 projections are based generally on federal, state, and local laws and regulations in effect as of the end of October 2013. 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 AEO2014 is completed, it may be considered in the projection.

AEO2014 is published in accordance with Section 205c of the U.S. Department of Energy (DOE) Organization Act of 1977 (Public Law 95-91), which requires the EIA Administrator to prepare annual reports on trends and projections for energy use and supply.

Projections by EIA are not statements of what will happen but of what might happen, given the assumptions and methodologies used for any particular scenario. The AEO2014 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 AEO2014 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 AEO2014 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 2014* Reference case (April 2014)

The AEO2014 Reference case included as part of this complete report, released in April 2014, was updated from the AEO2013 Reference case released in April 2013. 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:

Macroeconomic

- Revised U.S. Census Bureau population projections [*2*]. The population projection for 2040 in the AEO2014 Reference case is almost 6% below the 2040 projection used for the AEO2013 Reference case. Most of the revision in overall population growth results from a lower projection for net international migration, with younger age groups showing the largest differences from the earlier projection. The slower rate of population growth leads to less labor force growth, which contributes to slower GDP growth.

Residential, commercial, and industrial

- Revised base year residential equipment stocks and energy consumption for space heating, space cooling, and water heating, based on data from EIA's 2009 Residential Energy Consumption Survey (RECS), the most recent data available [*3*]. Estimates of appliance stocks and energy consumption for several miscellaneous electric loads also were updated, based on a report by Navigant Consulting Inc., to better reflect recent changes and trends in the residential sector [*4*].
- Updated and expanded representation of miscellaneous electric loads in the commercial sector, as well as personal computers and data center servers, based on the Navigant report, reflecting recent and expected trends in electronics use [*5*].
- Updated costs and improved representation of residential lighting applications, including wider representation of light emitting diode (LED) lighting and outdoor lighting, based on the 2009 RECS and two U.S. Department of Energy (DOE) reports [*6*, *7*].
- Revised handling of the regional efficiency standard for residential furnaces, based on an ongoing legal appeal of the standard. The regional standard scheduled to take effect in 2013 is not included in AEO2014 because of a court challenge and proposed settlement that would vacate the standard in question and require DOE to develop new standards for residential furnaces.
- Revised commercial capacity factors governing annual usage of major end-use equipment, based on an EIA-contracted analysis.
- Updated manufacturing sector data to reflect the 2010 Manufacturing Energy Consumption Survey (MECS) [*8*].
- Revised outlook for industrial production to reflect the effects of increased shale gas production and lower natural gas prices, resulting in faster growth for industrial production and energy consumption. The industries primarily affected include energy-intensive bulk chemicals and primary metals, both of which provide products used by the mining and other downstream industries, such as fabricated metals and machinery. The bulk chemicals industry is also a major user of natural gas and, increasingly, hydrocarbon gas liquid (HGL) feedstocks [*9*].
- Expanded process flow models for the cement and lime industry and the aluminum industry, allowing technologies based on energy efficiency to be incorporated, as well as enhancement of the cement model to include renewable fuels.

Transportation

- Implemented a new approach to vehicle miles traveled (VMT) projections for light-duty vehicles (LDVs), based on an analysis of VMT by age groups and the aging of the driving population over the course of the projection, which resulted in a significantly lower level of VMT growth after 2018 compared with AEO2013. On balance, demographic trends (such as an aging population and decreasing rates of licensing and travel among younger age groups) combine with employment and income factors to produce a 30% increase in VMT from 2012 to 2040 in AEO2014, compared with 41% growth in AEO2013.
- Added liquefied natural gas (LNG) as a potential fuel choice for freight rail locomotives and domestic marine vessels, resulting in significant penetration of natural gas as a fuel for freight rail (35% of freight rail energy consumption in 2040) but relatively minor penetration in domestic marine vessels (2% of domestic marine energy consumption in 2040).
- Adopted a new approach for estimating freight travel demand by region and commodity for heavy-duty vehicles (HDVs), rail, and domestic marine vessels, as well as updated fuel efficiencies for freight rail and domestic marine vessels.
- Updated handling of flex-fuel vehicle (FFV) fuel shares to better reflect consumer preferences and industry response. FFVs are necessary to meet the renewable fuels standard (RFS), but the phaseout of corporate average fuel economy (CAFE) credits for their sale, as well as limited demand from consumers, reduces their market penetration.
- Revised attributes for battery electric vehicles, including: (1) product availability, (2) electric drive fuel efficiency, and (3) non-battery system costs by vehicle size class, battery size, and added battery cost per kilowatthour based on vehicle power-to-energy ratio for vehicle type—applied to hybrid electric, plug-in hybrid electric, and all-electric vehicles.

Oil and natural gas production and product markets

- Revised network pricing assumptions based on benchmarking of regional natural gas hub prices to historical spot natural gas prices, using flow decisions based on spot prices, setting variable tariffs based on historical spot natural gas price differentials, and estimating the price of natural gas to the electric power sector off a netback from the regional hub prices [*10*].

- Allowed secondary flows of natural gas out of the Middle Atlantic region to change dynamically in the model based on relative prices, which enables a larger volume of natural gas from the Middle Atlantic's Marcellus formation to supply neighboring regions.
- Developed the estimated ultimate recovery of tight oil and shale gas on the basis of county-level data [*11*].
- Updated oil and gas supply module that explicitly reports technically recoverable resources of liquids in natural gas, enabling estimation of dry and wet natural gas.
- Improved representation of the dynamics of U.S. gasoline and diesel exports versus U.S. demand, through adoption of endogenous modeling [*12*].
- Added representation of the U.S. crude oil distribution system (pipelines, marine, and rail), to allow crude oil imports to go to logical import regions for transport to refineries, which enables crude imports and domestic production to move among refining regions and keeps imports of Canadian crude oil from flowing directly to U.S. Gulf refiners [*13*].
- Revised production outlook for nonpetroleum other liquids—gas-to-liquids, coal-to-liquids (CTL), biomass-to-liquids, and pyrolysis [*14*]—with lower production levels than in AEO2013, as more recent experience with these emerging technologies indicates higher costs than previously assumed [*15*].
- Revised representation of CO_2-enhanced oil recovery (EOR) that better integrates the electricity, oil and gas supply, and refining modules [*16*].

Electric power sector

- Revised approach to reserve margins, which are set by region on the basis of North American Electric Reliability Corporation/Independent System Operator requirements [*17*], and to capacity payments, which are calculated as a combination of levelized costs for combustion turbines and the marginal value of capacity in the electricity model.
- Revised handling of spinning reserves, with the required levels set explicitly, depending on the mix of generating technologies used to meet peak demand by region, to allow better representation of capacity requirements and costs in regions or cases with high penetration of intermittent loads.
- Revised assumptions concerning the potential for unannounced retirements of nuclear capacity in several regions to better reflect the impacts of rising operating costs and low electricity prices. Announced nuclear retirements are already incorporated as planned.
- Updated handling of Mercury and Air Toxics Standards (MATS) [*18*] covering the electric power sector, to reflect potential upgrades of electrostatic precipitators, requirements for plants with dry scrubbers to employ fabric filters, and revised costs for retrofits of dry sorbent injection and fabric filters.
- Updated treatment of the production tax credit (PTC) for eligible renewable electricity generation technologies—consistent with the American Taxpayer Relief Act of 2012 (ATRA) passed in January 2013 [*19*]—including revision of PTC expiration dates for each PTC-eligible technology, to reflect the concept of projects being declared "under construction" as opposed to being placed "in service," and extension of the expiration date of the PTC for wind generation projects by one year.

Future analyses using the AEO2014 Reference case will start from the version of the Reference case released with this complete report.

Endnotes

Links current as of April 2014

1. Regional Greenhouse Gas Initiative, "Program Review" (New York, New York: February 7, 2013), http://www.rggi.org/docs/ProgramReview/_FinalProgramReviewMaterials/Recommendations_Summary.pdf.
2. The new population projections were released on December 12, 2012. See U.S. Department of Commerce, "U.S. Census Bureau Projections Show a Slower Growing, Older, More Diverse Nation a Half Century from Now" (Washington, DC: December 12, 2012), https://www.census.gov/newsroom/releases/archives/population/cb12-243.html.
3. U.S. Energy Information Administration, "Residential Energy Consumption Survey (RECS): 2009 RECS Survey Data, Public Use Microdata File (Washington, DC: January 2013), http://www.eia.gov/consumption/residential/data/2009/index.cfm?view=microdata.
4. Navigant Consulting, Inc., *Analysis and Representation of Miscellaneous Electric Loads in the National Energy Modeling System (NEMS)* (Washington, DC: May 2013), prepared for U.S. Department of Energy, U.S. Energy Information Administration.
5. Navigant Consulting, Inc., *Analysis and Representation of Miscellaneous Electric Loads in the National Energy Modeling System (NEMS)* (Washington, DC: May 2013), prepared for U.S. Department of Energy, U.S. Energy Information Administration.
6. U.S. Department of Energy, Office of Energy Efficiency and Renewable Energy, *Residential Lighting End-Use Consumption Study: Estimation Framework and Initial Estimates* (Washington, DC: December 2012), http://apps1.eere.energy.gov/buildings/publications/pdfs/ssl/2012_residential-lighting-study.pdf.
7. U.S. Department of Energy, Office of Energy Efficiency and Renewable Energy, *2010 U.S. Lighting Market Characterization* (Washington, DC: January 2012), http://apps1.eere.energy.gov/buildings/publications/pdfs/ssl/2010-lmc-final-jan-2012.pdf.
8. U.S. Energy Information Administration, "Manufacturing Energy Consumption Survey (MECS): 2010 MECS Survey Data" (Washington, DC: March 19, 2013), http://www.eia.gov/consumption/manufacturing/data/2010/.
9. Growing production of wet natural gas and lighter crude oil has focused attention on natural gas liquids (NGL). EIA has developed and adopted a neutral term—"hydrocarbon gas liquid" (HGL)—to equate the supply (*natural gas plant liquids* [*NGPL*] + *liquefied refinery gases* [*LRG*]) and market (*NGL + refinery olefins*) terms. For example, liquefied petroleum gas (LPG) is currently defined by EIA as ethane, propane, normal butane, and isobutane and their olefins (ethylene, propylene, butylene, and isobutylene). This definition is inconsistent with definitions used by other federal agencies, international organizations, and trade groups, in that it implies that all the products are in a liquid state (ethane typically is not) and are used in the same way (higher-value olefins are used differently). Part of the HGL implementation redefines LPG to include only propane, butane, and isobutane and to exclude ethane and refinery olefins. The tables included in AEO2014 have been relabeled to conform to this newly adopted definition.
10. Estimating natural gas prices to the electricity generation sector based on hub prices, rather than the citygate prices as was done in prior years, is a better reflection of current market conditions, in which many large natural gas consumers are outside the citygate.
11. After accounting for infrastructure constraints and general development patterns, oil and natural gas resources in sweet spots are developed earlier than lower quality resources, based on net present value.
12. High U.S. crude oil production and low fuel costs have given U.S. refiners a competitive advantage over foreign refiners, as evidenced by high U.S. refinery utilization and increasing U.S. exports of gasoline and diesel fuel.
13. Oil imports from Canada now are required to go to Petroleum Administration for Defense District (PADD) 2 (Midwest: North Dakota, South Dakota, Nebraska, Kansas, Oklahoma, Minnesota, Iowa, Missouri, Wisconsin, Illinois, Michigan, Indiana, Ohio, Kentucky, and Tennessee); PADD 4 (Rocky Mountain: Montana, Idaho, Wyoming, Utah, and Colorado); and PADD 5 (West Coast: Washington, Oregon, Nevada, California, Arizona, Alaska, and Hawaii) for redistribution through the crude oil distribution infrastructure.
14. Pyrolysis is defined as the thermal decomposition of biomass at high temperatures (greater than 400°F, or 200°C) in the absence of air.
15. EIA undertook detailed assessments of these technologies in order to characterize key parameters considered in the model, such as capital cost, contingency factors, construction time, first year of operation, plant life, plant production capacity, efficiency, and feedstock and other operating costs.
16. When considering CO_2 EOR, the oil and gas supply module assesses a location and the availability and price of CO_2 from power plants and CTL facilities. The electric power plants now consider the market size and prices for CO_2 captured. The refining module assesses a location and the availability and price of CO_2 from CTL facilities. The power sector now assesses opportunities for plants equipped with carbon capture and storage, as the CO_2 produced at those facilities can be used for EOR operations. This enables the model to solve dynamically for the capture of CO_2 and the production of oil from anthropogenic CO_2 EOR.

17. North American Electric Reliability Corporation, *2013 Summer Reliability Assessment* (Atlanta, GA: May 2013), http://www.nerc.com/pa/RAPA/ra/ Reliability%20Assessments%20DL/2013SRA_Final.pdf (password required).

18. U.S. Environmental Protection Agency, "Mercury and Air Toxics Standards (MATS)," http://www.epa.gov/mats.

19. U.S. House of Representatives, 112th Congress, Public Law 112-240, "American Taxpayer Relief Act of 2012," Sections 401-412 (Washington, DC: January 2, 2013), http://www.gpo.gov/fdsys/pkg/PLAW-112publ240/pdf/PLAW-112publ240.pdf.

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Executive summary

Projections in the U.S. Energy Information Administration's *Annual Energy Outlook 2014* (AEO2014) 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, the AEO2014 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. AEO2014 also includes alternative cases that explore important areas of uncertainty for markets, technologies, and policies in the U.S. energy economy (see Appendix E for discussion of detailed case assumptions). Many of the implications of the alternative cases are discussed in the Issues in Focus section of AEO2014.

Key results highlighted in the AEO2014 Reference and alternative cases include:

- Growing domestic production of natural gas and oil continues to reshape the U.S. energy economy, largely as a result of rising production from tight formations, but the effect could vary substantially depending on expectations about resources and technology.
- Industrial production expands over the next 10 to 15 years as the competitive advantage of low natural gas prices provides a boost to the industrial sector with increasing natural gas use.
- There is greater upside uncertainty than downside uncertainty in oil and natural gas production; higher production could spur even more industrial growth and lower the use of imported petroleum.
- Improvement in light-duty vehicle (LDV) efficiency more than offsets modest growth in vehicle miles traveled (VMT) that reflects changing driving patterns, leading to a sharp decline in LDV energy use.
- Evolving natural gas markets spur increased use of natural gas for electricity generation and transportation, as well as expanded export opportunities.
- Improved efficiency of energy use in the residential and transportation sectors and a shift away from more carbon-intensive fuels such as coal for electricity generation help to stabilize U.S. energy-related carbon dioxide (CO_2) emissions.

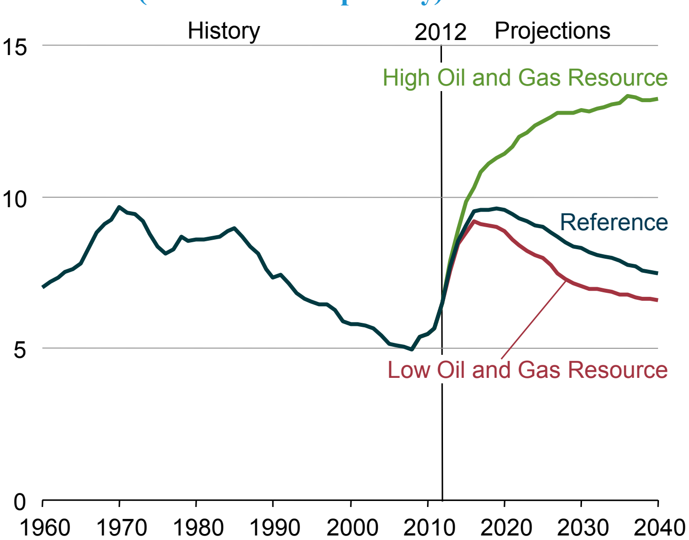
Expected gains in tight oil production drive projected growth in total petroleum and other liquids production

Growth in crude oil production from tight oil and shale formations supported by identification of resources and technology advances have supported a nearly fourfold increase in tight oil production from 2008, when it accounted for 12% of total U.S. crude oil production, to 2012, when it accounted for 35% of total U.S. production. Total projected U.S. crude oil production in the AEO2014 Reference case reaches 9.6 million barrels per day (MMbbl/d) in 2019—3.1 MMbbl/d more than in 2012. Over the same period, tight oil production grows by 2.5 MMbbl/d, to 4.8 MMbbl/d or 50% of the national total.

In the Reference case, tight oil production begins to slow after 2021, contributing to a decline in total U.S. oil production through 2040. However, tight oil development is still at an early stage, and the outlook is uncertain. Changes in U.S. crude oil production depend largely on the degree to which technological advances allow production to occur in potentially high-yielding tight and shale formations. They also depend on the assumed estimated ultimate recovery (EUR) for wells drilled in those formations, in addition to assumptions about well spacing and production patterns. To address these uncertainties, AEO2014 includes High Oil and Gas Resource and Low Oil and Gas Resource cases (Figure ES-1). In the High Oil and Gas Resource case, tight oil production reaches 8.5 MMbbl/d in 2035 (compared to 3.7 MMbbl/d in the Reference case), with total U.S. crude oil production reaching 13.3 MMbbl/d in the following year (compared to 7.8 MMbbl/d in the Reference case).

A comparison of the Reference case and High Oil and Gas Resource case demonstrates the significant impact that technological development and productivity gains in tight oil plays can have on net imports of crude oil and petroleum products. In the Reference case, the share of net crude oil and petroleum product imports as a percentage of total U.S. product consumed declines from 41% in 2012 to 25% in 2016, remains close to that level for several years, and then rises to 32% in 2040 (Figure ES-2). In the High Oil and Gas Resource case, domestically produced crude oil displaces more expensive imported crude at domestic refineries, and U.S. finished petroleum products become more competitive worldwide. The share of total U.S. product consumed represented by net crude oil and petroleum product imports in the High Oil and Gas Resource case declines to 15% in 2020 and continues to fall through 2040. The United States becomes a net exporter of crude oil and petroleum products at the end of the projection period.

Figure ES-1. U.S. crude oil production in three cases, 1960-2040 (million barrels per day)



Among the most uncertain aspects of this analysis are the potential effects of alternative resource and technology assumptions on the global market for liquid fuels, which is highly integrated. Regardless of how much the United States reduces its reliance on imported liquids, consumer prices will not be insulated from global oil prices set in global markets for crude oil and petroleum products. Strategic choices made by leading oil-exporting countries could result in U.S. price and quantity changes that differ significantly from those presented in this outlook.

U.S. industrial production is spurred by abundant and relatively inexpensive natural gas

The AEO2014 Reference case projects robust growth in industrial production, with the manufacturing sector benefitting from abundant and relatively inexpensive natural gas, especially in the first 15 years of the projection. Low natural gas prices and increased availability of natural gas and related resources such as hydrocarbon gas liquids (HGL) benefit the U.S. industrial sector in multiple ways. Natural gas is used as a fuel to produce heat and to generate electricity and, along with HGL products, is also used as a feedstock to produce chemicals, pharmaceuticals, and plastics. In addition, with generally lower energy prices resulting in more rapid economic growth, demand for industrial products increases.

Bulk chemicals account for much of the increased growth in manufacturing output in the Reference case (Figure ES-3). Industrial production of bulk chemicals, which also benefits from increased supply of HGL, grows by 3.4%/year from 2012 to 2025 in the AEO2014 Reference case. The near-term competitive advantage diminishes over time, however, and growing competition from abroad slows U.S. output growth after 2030 as domestic natural gas becomes less cost-advantaged compared with prices at other locations, resulting in increased competition from newer facilities that are developed abroad.

The higher level of industrial production leads to growth in natural gas consumption in the U.S. industrial sector, from 8.7 quadrillion British thermal units (Btu) in 2012 to 10.6 quadrillion Btu in 2025 in the Reference case. Most of the increase in industrial natural gas demand is the result of output growth in the manufacturing sector. Energy-intensive industries with high rates of growth include paper products, food products, bulk chemicals, and metal-based durables.

Different assumptions about economic growth or about oil and gas resources and technology result in large variations in industrial output, with bulk chemicals showing more variation in the High and Low Oil and Gas Resource cases and the rest of the manufacturing sector showing more variation in the High and Low Economic Growth cases. Output from the bulk chemicals industry is more responsive to variations in energy prices than is output from the rest of the industrial sector, and shipments continue to grow after 2035 in the High Oil and Gas Resource case, as indicated in Figure ES-3.

Transportation energy use continues to decline, with light-duty vehicles sharply reducing gasoline consumption due to fuel efficiency and changing usage patterns

Fuel use in the U.S. transportation sector has changed fundamentally in the past several years. In the AEO2014 Reference case, the factors contributing to declining light-duty vehicle (LDV) energy use continue and intensify, resulting in declines in motor gasoline consumption over the projection period.

LDV fuel efficiency is driven by increasingly stringent regulatory standards. In the Reference case, the fuel efficiency of the LDV stock in miles per gallon (mpg), excluding light-duty commercial trucks, increases by 2%/year to 37.2 mpg in 2040 from 21.5 mpg in 2012. While motor gasoline remains the dominant fuel, growing market penetration of diesel, biofuels, hybrid-electric, and plug-in electric systems gradually reduces its share of the LDV fuel market.

AEO2014 includes a new demographic profile of driving behavior by age and gender. Total vehicle miles traveled (VMT) increases at an average annual rate of 0.9% from 2012 to 2040, due to changes in driving behavior that are related to age and gender demographics. Older drivers increase as a proportion of the U.S. driving population, with their higher licensing rates but lower-than-average mileage

Figure ES-2. Net import share of U.S. petroleum and other liquids consumption in three cases, 1990-2040 (percent)

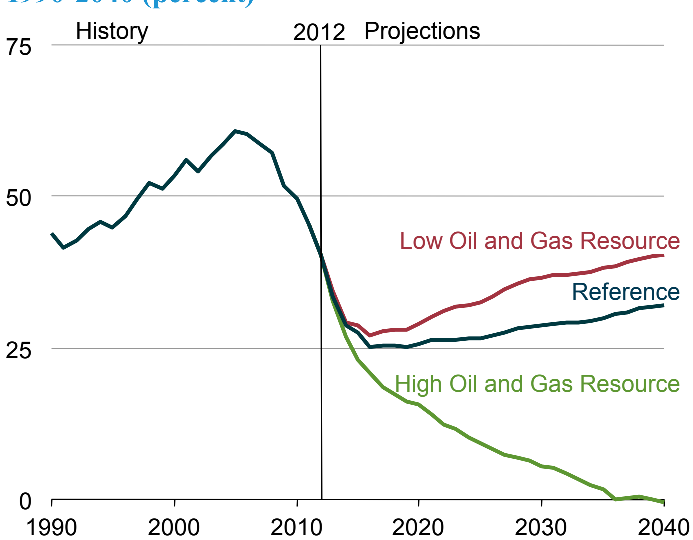
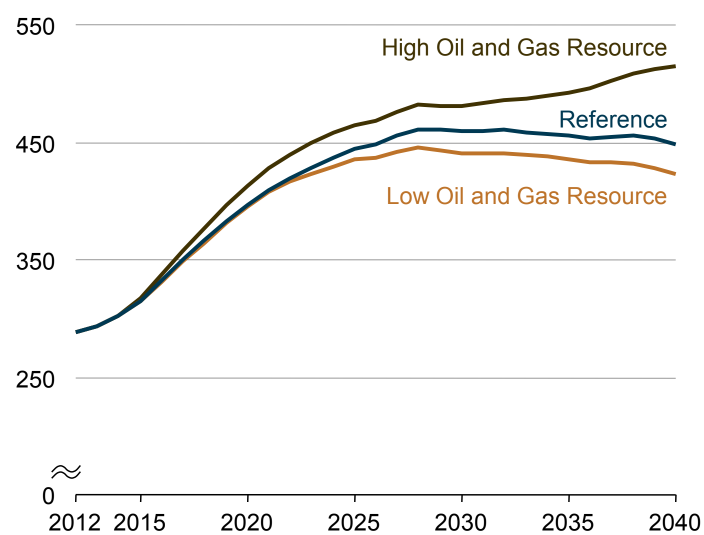


Figure ES-3. Value of shipments of bulk chemicals in three cases, 2012-40 (billion 2005 dollars)



per capita contributing to a gradual increase in total VMT. However, rising fuel economy more than offsets the modest growth in VMT, and energy consumption by LDVs declines in the Reference case from 8.4 MMbbl/d in 2012 to 6.4 MMbbl/d in 2040.

The importance of demographic changes for VMT and transportation energy consumption is highlighted by AEO2014 alternative cases in which variations in these assumptions result in higher or lower fuel use (Figure ES-4). In a High VMT case, U.S. LDVs consume 5% more energy by 2040, while in a Low VMT case they consume 18% less energy than in the Reference case. This variation in projected energy demand from the transportation sector has further effects on other key energy sector indicators, including fuel use, imports, and CO_2 emissions.

Abundant supply of natural gas spurs greater use for electricity generation and transportation

Natural gas is an attractive fuel for new generating capacity. In some regions, natural gas-fired generation captures markets formerly supplied by coal-fired and nuclear plants, and by 2035 natural gas surpasses coal as the nation's largest source of energy for electricity generation (including the power sector and end-use sector generation) in the Reference case (Figure ES-5). In the first decade of the projection, growth in electricity generation from renewables tends to be largely policy-driven. However, as Reference case natural gas prices rise and the capital costs of renewable technologies—particularly wind and solar—decrease over time, renewable generation becomes more competitive, accounting for 16% of total electricity generation in 2040.

If additional existing coal-fired and nuclear generating capacity were retired, natural gas-fired generation could grow more quickly to fill the void. In recent years, the number of coal and nuclear plant retirements has increased, in part due to a decline in profitability as low natural gas prices have influenced the relative economics of those facilities. The Accelerated Coal Retirements case assumes that both coal prices and coal plant operating costs are higher than in the Reference case, leading to additional coal plant retirements. In this case, natural gas-fired generation overtakes coal-fired generation in 2019, and by 2040 the natural gas share of total generation reaches 43%. In the Accelerated Coal and Nuclear Retirements case, the natural gas share of total generation in 2040 grows to 47%. In both cases, renewable generation also increases relative to the Reference case. However, barring a breakthrough in electricity storage or related technologies, renewable technologies cannot fully replace the baseload generation lost as a result of coal and nuclear plant retirements, and total additions of natural gas-fired combined-cycle capacity in these cases are 32% to 50% higher than in the Reference case over the projection period.

Freight rail is considered a potential additional source of natural gas use in AEO2014. Any transition from diesel to natural gas as a fuel for freight locomotives will depend on economics, infrastructure needs, and railroads' decisions with regard to risk and uncertainty. For AEO2014, alternative cases were developed that anticipate varying degrees of natural gas penetration into the U.S. freight rail market. In the High Rail LNG case, natural gas is used to meet nearly all freight rail energy demand by 2040, while in the Reference case it gains 35% of the rail fuel market by that date. However, because the transportation sector is a relatively small consumer of natural gas compared to other sectors, the seemingly dramatic fuel switch from the perspective of freight rail is only a minor change in overall U.S. natural gas consumption.

A shift away from more carbon-intensive fuels for electricity generation helps to stabilize energy-related carbon dioxide emissions

In the AEO2014 Reference case, total U.S. energy-related emissions of CO_2 remain below the 2005 level in every year through 2040. In the Reference case, CO_2 emissions from the U.S. industrial sector exceed emissions from the transportation sector

Figure ES-4. U.S. light-duty vehicle energy use in three cases, 1995-2040 (million barrels of oil equivalent per day)

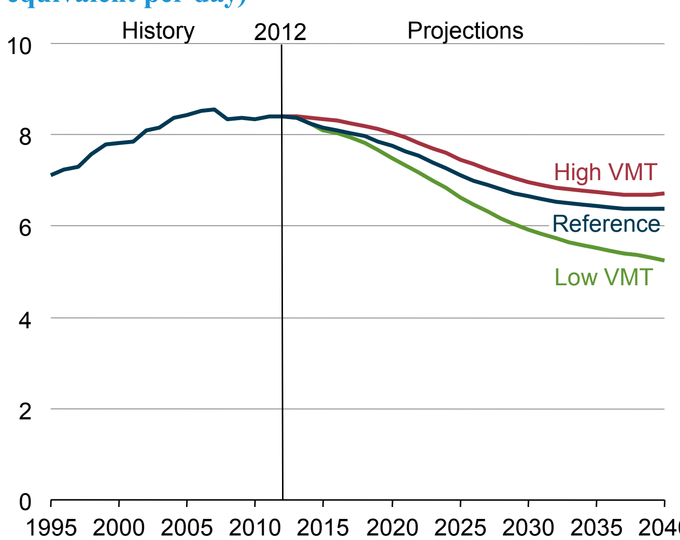
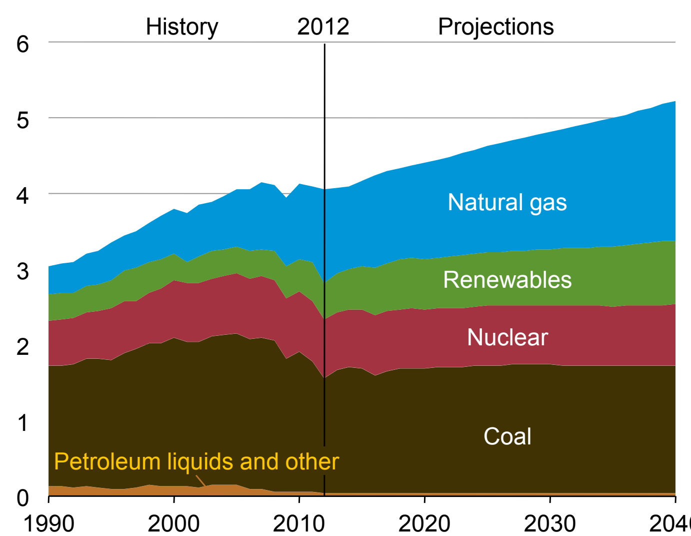


Figure ES-5. Electricity generation by fuel in the Reference case, 1990-2040 (trillion kilowatthours)



beginning in 2024, for the first time since the late 1990s, as new fuel economy standards, biofuel mandates, and shifts in consumer behavior result in declining or stable transportation sector emissions from 2012 through 2033. After 2033 they begin to rise again, with freight transport increasing the demand for diesel, while demand for motor gasoline declines. In the electric power sector, emissions from coal combustion remain below 2011 levels through 2040 as more power plants are fueled by lower-carbon fuels, including natural gas and renewables.

CO_2 emissions in the electric power sector are dependent on the overall level of demand for electricity, as well as the mix of generating technologies used to satisfy that demand. In the Reference case, the average emission rate per kilowatthour of generation declines over time, primarily because the coal-fired share of total generation declines and is replaced predominantly with natural gas-fired generation, which is less carbon intensive than coal. In addition, the combined share of generation from nuclear and renewable fuels is gradually increasing throughout the projection, maintaining a generally consistent contribution of carbon-free generation resources. As a result, although generation in the electric power sector increases by 25% from 2012 to 2040, the sector's CO_2 emissions increase by only 11% over the same period. In most of the alternative cases, a decline in demand results in a greater decline in fossil-fueled generation and CO_2 emissions, as less efficient oil, coal, and natural gas plants reduce output or are retired. For example, in the Low Electricity Demand case, with retail electricity sales in 2040 about the same as in 2012, generation in the electric power sector is 20% lower, and CO_2 emissions are 22% lower, than projected in the Reference case.

CO_2 emissions in the power sector are highly sensitive to the relative generation shares of different fuel types, and larger shifts away from fossil fuels lead to declining emissions. While the retirement of coal-fired plants in the near term contributes to lower levels of CO_2 emissions, in the Accelerated Coal Retirements case, where coal retirements through 2040 are more than double those in the Reference case, CO_2 emissions decline by 11% from 2012 levels and are 20% below Reference case levels in 2040.

In general, growth of renewable generation is associated with a reduction in CO_2 emissions in the electric power sector. In the Low Renewable Technology Cost case, nonhydropower renewable generation grows at an average annual rate of 4.7% from 2012 to 2040 (Figure ES-6), compared to 3.2% in the Reference case, and electric power sector CO_2 emissions in 2040 are about 4% below the Reference case level. When growth in nonhydropower renewable generation is coupled with electricity demand growth that exceeds that in the Reference case, the impact on emissions may be more ambiguous. In the High Economic Growth case, although nonhydropower renewable generation grows by an average of 4.1%/year from 2012 to 2040, total electricity demand grows by 1.2%/year and electric power sector CO_2 emissions in 2040 are about 4% higher than in the Reference case.

In most cases that include high levels of nonhydropower renewable generation, electric power sector CO_2 emissions still increase slightly, if not as rapidly as in the Reference case, between 2012 and 2040, reflecting factors such as generation subsidies that reduce the cost of electricity and its price, raising demand. Cases that place a fee on CO_2 emissions throughout the energy sector, starting at either \$10 or \$25/ton and rising at a rate of 5%/year thereafter (the GHG10 and GHG25 cases), and a case that combines the GHG10 case with the High Oil and Gas Resource case (the GHG10 and Low Gas Prices case) are notable exceptions. In those cases, because the additional cost of operating generators that use fossil fuels results in both a decrease in overall electricity demand and significant substitution of nonhydropower renewable energy sources for fossil-fueled generation, total electric power sector CO_2 emissions in 2040 are between 36% and 82% below the Reference case total of 2,259 million metric tons, respectively, and total energy-related CO_2 emissions from all sources in 2040 are between 15% and 36% below the Reference case total of 5,599 million metric tons (Figure ES-7).

Figure ES-6. Nonhydropower renewable electricity generation in eight cases, 2005-40 (billion kilowatthours)

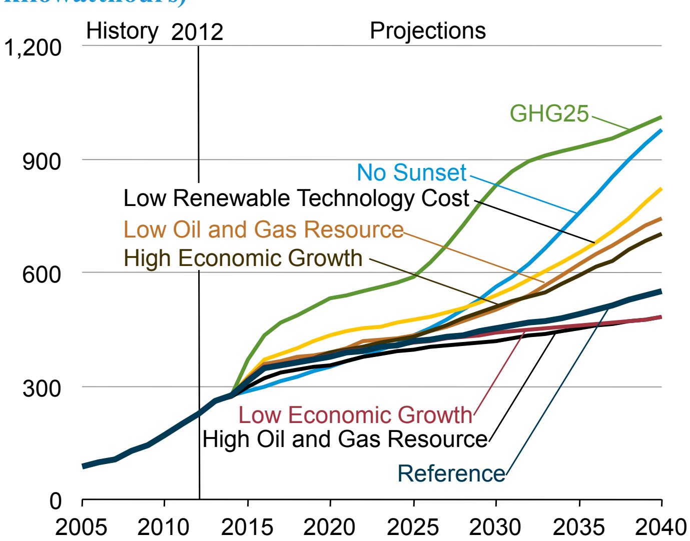


Figure ES-7. Energy-related carbon dioxide emissions in five cases, 2000-40 (million metric tons)

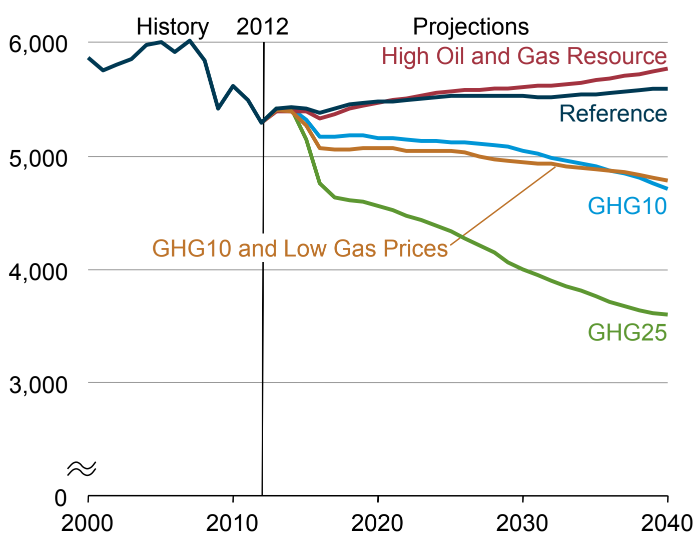


Figure and table sources

Links current as of April 2014

Figure ES-1. U.S. crude oil production in three cases, 1960-2040: History: U.S. Energy Information Administration, *Monthly Energy Review,* September 2013, DOE/EIA-0035(2013/09). **Projections:** AEO2014 National Energy Modeling System, runs REF2014.D102413A, LOWRESOURCE.D112913A, and HIGHRESOURCE.D112913B.

Figure ES-2. Net import share of U.S. petroleum and other liquids consumption in three cases, 1990-2040: U.S. Energy Information Administration, *Monthly Energy Review,* September 2013, DOE/EIA-0035(2013/09) (Washington, DC, September 2013). **Projections:** AEO2014 National Energy Modeling System, runs REF2014.D102413A, LOWRESOURCE.D112913A, and HIGHRESOURCE.D112913B.

Figure ES-3. Shipments of bulk chemicals in three cases, 2012-40: AEO2014 National Energy Modeling System, runs REF2014.D102413A, LOWRESOURCE.D112913A, and HIGHRESOURCE.D112913B.

Figure ES-4. U.S. light-duty vehicle energy use in three cases, 1995-2040: History: U.S. Department of Transportation, Federal Highway Administration, National Household Travel Survey, http://nhts.ornl.gov/download.shtml. **Projections:** AEO2014 National Energy Modeling System, runs REF2014.D102413A, LOWVMT.D020314B, and HIGHVMT.D020314D.

Figure ES-5. Electricity generation by fuel in the Reference case, 1990-2040: History: U.S. Energy Information Administration, *Monthly Energy Review,* September 2013, DOE/EIA-0035(2013/09) (Washington, DC, September 2013). **Projections:** AEO2014 National Energy Modeling System, run REF2014.D102413A.

Figure ES-6. Nonhydropower renewable electricity generation in eight cases, 2005-40: History: U.S. Energy Information Administration, *Monthly Energy Review,* September 2013, DOE/EIA-0035(2013/09) (Washington, DC, September 2013). **Projections:** AEO2014 National Energy Modeling System, runs REF2014.D102413A, CO2FEE25.D011614A, NOSUNSET.D121713A, LCR_2014.D120613A, LOWRESOURCE.D112913A, HIGHRESOURCE.D112913B, LOWMACRO.D112913A, and HIGHMACRO.D112913A.

Figure ES-7. Energy-related carbon dioxide emissions in five cases, 2000-40: History: U.S. Energy Information Administration, *Monthly Energy Review,* September 2013, DOE/EIA-0035(2013/09) (Washington, DC, September 2013). **Projections:** AEO2014 National Energy Modeling System, runs REF2014.D102413A, HIGHRESOURCE.D112913B, CO2FEE10.D011614A, CO2FEE25.D011614A, and CO2FEE10HR.D011614A.

Legislation and regulations

Introduction

The *Annual Energy Outlook 2014* (AEO2014) generally represents current federal and state legislation and final implementation of regulations as of the end of October 2013. The AEO2014 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) [*1*]. The potential impacts of proposed legislation, regulations, or standards—or of sections of authorizing legislation that have been enacted but are not funded, or for which parameters will be set in a future regulatory process—are not reflected in the AEO2014 Reference case, but some are considered in alternative cases. This section summarizes federal and state legislation and regulations newly incorporated or updated in AEO2014 since the completion of the *Annual Energy Outlook 2013* (AEO2013). It also summarizes selected rules and regulations that have been proposed recently and have the potential to affect the projection significantly.

Examples of federal and state legislation and regulations incorporated in the AEO2014 Reference case, or whose handling has been modified, include:

- Incorporation of the revised emissions standards and banking provisions for carbon dioxide (CO_2) announced by the nine-state Regional Greenhouse Gas Initiative in February 2013, which lowered the program's emissions cap by 45% starting in 2014 [*2*].
- Updated handling of the mandated volume for biofuels established for the renewable fuel standard (RFS) by the Energy Policy Act of 2005 (EPACT2005) [*3*] and expanded by the Energy Independence and Security Act of 2007 (EISA2007) [*4*] to reflect final and proposed actions by the U.S. Environmental Protection Agency (EPA) to set obligations for both cellulosic biofuels and total renewable fuels below the legislated targets, using the discretion allowed by the law.
- Incorporation of modifications to existing state Renewable Portfolio Standard (RPS) or similar laws to reflect recent modifications to existing programs in Colorado, Connecticut, Maryland, Montana, Minnesota, Nevada, New Mexico, and Washington [*5*]. The changes that were enacted affect some aspects of the laws and implementing regulations, but in general they do not have significant substantive effects on the representation of the RPS programs in AEO2014.

There are many other pieces of legislation and regulation that might be enacted in the not-too-distant future, and some laws include sunset provisions that may be extended. However, it is difficult to discern future outcomes. 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 AEO2014 or in other analyses completed by the U.S. Energy Information Administration (EIA). In addition, at the request of both federal agencies and Congress, EIA has regularly examined the potential implications of other possible energy options in special analyses that can be found on the EIA website at http://www.eia.gov/analysis/reports.cfm?t=138.

LR1. Recent environmental regulations in the electric power sector

Several environmental rules recently implemented at the federal and state levels affect the AEO2014 projections for the electric power sector. While not considered in the AEO2014 Reference case, the EPA is also currently in the process of developing new rules to address electric power plant air emissions, the impact of cooling water intake systems on aquatic life, and coal ash disposal methods. New rules that may be promulgated could have significant impacts on the projected fuel mix for electric power generation. The following discussion summarizes programs and rules included in the AEO2014 Reference case.

Recent regional policy modifications

The Regional Greenhouse Gas Initiative (RGGI) is a regional cap-and-trade program for CO_2 emissions that applies specifically to fossil-fueled electric power plants larger than 25 megawatts (MW) located in each of the nine participating Northeastern states [*6*]. When it took effect in 2009, RGGI became the first mandatory market-based (cap-and-trade) CO_2 reduction program in the United States. The cap was tightened primarily because actual CO_2 emissions in the region since the start of the program in 2009 have been roughly 35% below the cumulative cap. The lower level of emissions is attributed primarily to historically low natural gas prices, which have shifted a large share of electricity generation in the region toward natural gas, and to lower overall electricity demand.

CO_2 emissions in the RGGI region comprised only 4% of the total emissions from the electric power sector in the United States in 2012. RGGI is one of the two legally mandated CO_2 cap-and-trade reduction programs in the United States, the other being the California cap-and-trade program that was an outgrowth of California's Assembly Bill 32, the Global Warming Solutions Act of 2006 (AB 32) [*7*].

In 2005, when CO_2 emissions in the participating states reached their annual peak, coal comprised 23%, natural gas 25%, and petroleum 12% of the regional generation mix. By 2012, coal's share had declined to 9%, the natural gas share had risen to 44%, and the petroleum share had fallen below 1%.

At the same time that the shift in fuels for electricity generation has lowered the carbon intensity of electricity generation in the region, demand for electricity in the Northeast has been flat or declining. Average annual retail electricity sales in the nine participating states from 2009 through 2012 were 6% below the annual sales in 2005.

Despite the reduction in the cap beginning in 2014, it remains to be seen whether the updated program caps will result in significant emissions reductions compared to the outcomes that might occur absent the new caps. CO_2 emissions in 2012 in the participating states were still only 92 million short tons, close to the 2014 target cap of 91 million short tons. However, the cap is designed to tighten annually through 2020. In the first half of 2013, CO_2 emissions from coal-fired generation were up both in the RGGI region and nationally compared with 2012 levels, which indicates that the revised cap could become more binding in the future.

Because of a surplus of allowances during the initial years of RGGI, the CO_2 value of the allowances remained close to the program's price floor of $1.93/ton of CO_2 allowed in each quarterly auction. The value of allowances increased to $3.00/ton of CO_2 in the latest auction, as market participants may be anticipating a rise in the future value of allowances. RGGI states use allowance revenues for a variety of programs that support cleaner generation and/or energy efficiency programs that reduce demand. Unless the programs supported by RGGI auction revenues are funded at the same level using other funding sources in the absence of RGGI, they will provide a tangible incremental reduction in emissions.

The RGGI program update grants the ability for previously unused allowances from the early years of the program to be saved and applied after 2014, as limits become more stringent—a strategy often referred to as "banking allowances." Additional flexibility exists in the program through the recently created Cost Containment Reserve, which effectively creates a price ceiling for allowances. When the price hits a given level, program participants can purchase a set level of allowances at a defined fixed price. This ceiling is intended to prevent allowance prices from rising above defined levels. The price trigger starts at $4/ton of CO_2 in 2014 and rises to $10/ton of CO_2 in 2017.

The program also allows for the limited use of CO_2 offsets as a compliance option. RGGI program participants are permitted to cover 3.3% of their emissions using offsets. Although the RGGI caps have been lowered, it remains to be seen how much the new caps will affect generation choices and related emissions.

Recent federal environmental regulations modeled in AEO2014

The Mercury and Air Toxics Standards (MATS) [*8*] requires fossil-fuel steam electric generators to meet limits based on maximum achievable control technologies (MACT) to control emissions of acid gases, toxic metals, and mercury. The standards will take effect by April 2015 for electric generation units with capacities greater than 25 MW. The rule allows for state environmental permitting agencies to grant one-year compliance extensions, which AEO2014 assumes will be granted, and all applicable units must begin to comply with the rule at the beginning of 2016. AEO2014 assumes that, in order to comply with the rule, all qualifying coal-fired power plants will be equipped with either flue gas desulfurization (FGD) scrubbers or dry sorbent injection (DSI) systems and activated carbon injection if warranted for mercury control. The control equipment needed to reduce mercury is specific to each plant configuration and coal type [*9*].

MATS is currently being challenged in the U.S. Court of Appeals for the District of Columbia Circuit in *White Stallion Energy Center et al. v. U.S. EPA* [*10*]. The case was heard in December 2013, and a decision is expected in the spring of 2014.

The Clean Air Interstate Rule (CAIR) [*11*] is a cap-and-trade program aimed at reducing emissions of sulfur dioxide (SO_2) and nitrogen oxides (NO_X) from fossil-fueled power plant units with capacities greater than 25 MW in 27 eastern states and the District of Columbia. The emissions caps went into effect in 2009 for NO_X and in 2010 for SO_2. Both caps are scheduled to be tightened in 2015. AEO2014 includes the CAIR cap-and-trade program for the applicable regions. The FGD scrubbers or DSI systems required by MATS result in SO_2 emissions falling to levels lower than the CAIR cap. Therefore, after MATS is in full effect starting in 2016, SO_2 emissions decline significantly below the CAIR cap, essentially making CAIR's SO_2 cap nonbinding [*12*].

CAIR was reinstated after the Cross-State Air Pollution Rule (CSAPR) was vacated by the U.S. Court of Appeals for the District of Columbia Circuit in August 2012 [*13*]. However, the U.S. Supreme Court agreed in June 2013 to review the D.C. Circuit Court's decision and heard the case in December 2013 [*14*]. A court decision is expected in the spring of 2014. If the Supreme Court reverses the D.C. Circuit Court's ruling, CSAPR will replace CAIR.

LR2. Handling of the Renewable Fuels Standard in AEO2014

The Renewable Fuel Standard (RFS) was established by the Energy Policy Act of 2005 [*15*] and was expanded by the Energy Independence and Security Act of 2007 (EISA2007) [*16*]. It requires the EPA to set requirements for the renewable content of gasoline and diesel fuel. Refiners and importers of gasoline and diesel fuel are obligated to blend renewable fuels in proportion to the volumes of gasoline and diesel fuel sold. There are four interrelated requirements, for cellulosic biofuels, biomass-based diesel, advanced biofuels, and total renewable fuels. Compliance with the RFS is tracked via Renewable Identification Numbers (RINs), which are generated when eligible biofuels are produced or imported and conveyed with the physical volume of renewable fuel through subsequent sales until they are blended with a petroleum product. Once the fuel is blended, the RINs can be separated from the physical volumes and "retired"—that is, turned in to the EPA to demonstrate compliance. RINs also can be sold or saved ("banked") for compliance either in the year they were generated or in the following year.

EPA sets the RFS target volumes every year in reference to legislated targets in EISA2007, public comments, and input from other government agencies. Since the expansion of the RFS program for the 2009 compliance year, the EPA has adhered to the legislated volumes of total renewable fuel, advanced biofuel, and biomass-based diesel but has often set the requirement for cellulosic biofuel well below the legislated target, given the very low commercial availability of cellulosic biofuel. EISA2007 also included new Corporate Average Fuel Economy (CAFE) standards, which have played and will continue to play a role in reducing gasoline consumption. Declines in gasoline consumption reduce the number of gallons of ethanol that can be used in E10, a fuel containing 10% ethanol by volume that is compatible with all existing gasoline-powered vehicles. EPA announced in its 2013 RFS final rule that it expected to reduce the total renewable fuel and advanced biofuel obligations to levels below the statutory levels for 2014, in order to allow the ethanol share of the gasoline pool to remain close to 10%.

The AEO2014 projections for quantities and costs of gasoline, diesel, and other liquid fuels are handled by the National Energy Modeling System's Liquid Fuels Market Model (LFMM), which includes a representation of the U.S. petroleum refining system, biofuels production, and marketing of liquid fuels to end users. The modeling structure allows for additions and adjustments in the liquid fuels supply chain in order to meet new demand or to comply with changing product specifications. A variety of feedstocks and technologies for the production of RIN-eligible renewable fuels can be represented, depending on the market and regulatory conditions (including future product specifications for gasoline and diesel fuel) for each AEO2014 case.

AEO2014 assumes that cellulosic fuel production and requirements will grow gradually from current low levels. For biomass-based diesel, the assumed production requirement is constant at 1.92 billion ethanol-equivalent gallons. The advanced biofuels production requirement, on the other hand, decreases by 425 million gallons from 2014 to 2015.

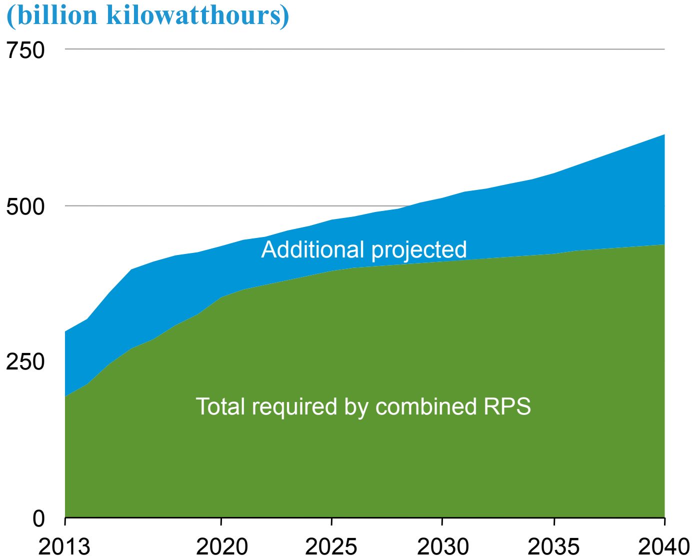
The reintroduction of the $1.00-per-gallon biodiesel blending tax credit in 2013 incentivized biodiesel production above the RFS level. That tax credit sunset at the end of 2013, and the AEO2014 Reference case does not assume that it is reinstated. The California Low Carbon Fuels Standard is expected to draw more sugarcane ethanol into California, generating more advanced RINs. After 2015, the total quantity of advanced biofuels needed to meet the RFS is assumed to increase only slowly, remaining well below the legislated target of 21 billion gallons in 2022. The total biofuels production requirement was set at 15.2 billion gallons in 2014 to reflect the gasoline market's limited ability to absorb additional ethanol in the near term. The total renewable fuels requirement is also assumed to grow slowly and remains well below the legislated target of 36 billion gallons in 2022.

LR3. State renewable energy requirements and goals: update through 2013

To the extent possible, AEO2014 reflects state laws and regulations in effect at the end of October 2013 that require the addition of renewable generation or capacity by utilities doing business in the state [*17*] to meet RPS requirements. The projection does not include laws and regulations with either voluntary goals or targets that can be substantially satisfied with nonrenewable resources. In addition, the projection does not account for 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 model because they could be met with existing capacity and/or projected growth based on modeled economic and policy factors.

States are projected to meet their ultimate RPS targets in the AEO2014 Reference case. The RPS compliance constraints in most regions are approximated, however, because National Energy Modeling System is not a state-level model, and each state generally represents only a portion of one of the NEMS electricity regions. In general, EIA has confirmed the states' requirements through original legislative or regulatory documentation, although the Database of State Incentives for Renewables & Efficiency was also used to support those efforts [*18*]. The aggregate RPS requirement for various mandatory state programs, as modeled for AEO2014, is shown in Figure LR3-1. In 2025, the targets account for slightly less than 10% of U.S. electricity sales.

Figure LR3-1. Total qualifying renewable generation required for combined state renewable portfolio standards and projected total achieved, 2013-40 (billion kilowatthours)



At present, most states are meeting or exceeding their required levels of renewable generation, based on qualified generation or purchase of renewable energy credits [*19*]. 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.
- Significant reductions in the cost of wind, solar, and other renewable technologies.
- Generally slower growth of electricity sales.
- Complementary state and local policies that either reduce the cost (for example, equipment rebates) or increase the revenue streams (for example, net metering) associated with RPS-eligible technologies.

EIA projects that, overall, RPS-qualified generation will continue to meet or exceed aggregate mandatory targets for state RPS programs through 2040, as shown in Figure LR3-1.

The aggregate near-term surplus of qualified generation is supported by projected near-term renewable capacity additions but declines slightly as growth in renewable capacity slows toward the end of this decade and RPS targets catch up with supply. The surplus widens again in the final two decades of the projection period, as renewable generation technologies become increasingly competitive with conventional generation sources and state targets generally do not increase beyond 2025.

It is important to note, however, that the aggregate targets and qualifying generation shown in Figure LR3-1 may mask significant regional variation, as well as technology- or tier-specific shortfalls. While some regions may produce excess qualifying generation, others may produce just enough to meet the requirement or may need to import generation from adjoining regions to meet state targets. Furthermore, even though there is more qualifying generation in aggregate than is needed to meet the targets, states with technology-specific goals could still have deficits for certain technologies. Also, this projected pattern of aggregate surplus 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 in their absence. It does, however, suggest that state RPS programs will not be the sole reason for future growth in renewable generation, and that the importance of RPS targets in contributing to growth in renewable generation will decline over time.

Currently, 29 states and the District of Columbia have enforceable RPS or similar laws (Table LR3-1) [*20*]. Under such standards, each state determines its own levels of renewable generation, eligible technologies [*21*], and noncompliance penalties. No new RPS programs have been enacted since 2009. There have been a number of modifications to existing programs in recent years, however, building on state implementation experience and changing market conditions.

The year 2013 saw a large number of proposed legislative modifications to existing RPS programs [*22*], including some attempts to weaken the targets of existing programs significantly. However, only a small subset was enacted, and no states passed major rollbacks or repeals of RPS programs. The changes that were enacted affect some aspects of the laws and implementing regulations, but in general they do not have substantive effects on the representation of state RPS programs in the AEO2014 Reference case. Key changes include:

Colorado

Senate Bill 13-252 [*23*], signed into law in June 2013, doubles the renewable energy target for large electric cooperatives and cooperative associations to 20% of total electric sales by 2020. The law also adds a renewable distributed generation requirement for electric cooperatives, removes preferential credit multipliers for in-state eligible sources, and expands the set of qualifying energy sources to include coal-mine methane and pyrolysis gas from municipal solid waste.

Connecticut

Senate Bill 1138 [*24*], enacted in June 2013, relaxes restrictions on how hydroelectric generation can be applied to Connecticut's RPS. The statute expands the set of qualifying Class I resources to include run-of-river hydropower up to 30 MW—an increase over the previous cap of 5 MW—as well as additional sources, such as geothermal electric and some types of biogas. In addition, large-scale hydropower (greater than 30 MW) could, under specified circumstances, be allowed to meet an increasing portion of the RPS, starting at 1% of sales in 2016 and rising to 5% of sales by 2020.

Maryland

The Maryland Offshore Wind Energy Act of 2013, House Bill 226 [*25*], was enacted in April 2013. The legislation adds to Maryland's existing RPS an offshore wind technology-specific requirement of up to 2.5% of total sales starting in 2017. Qualifying offshore facilities must be located in specific areas of the Outer Continental Shelf and are subject to a defined process for approval by the Maryland Public Service Commission. Projects will be subject to several cost containment triggers: the impact on residential customers cannot exceed $1.50 per month, and renewable energy credits for offshore wind should not exceed $190 per MWh.

Minnesota

In May 2013 Minnesota enacted House Floor 729 [*26*], which mandates that investor-owned utilities meet a solar technology-specific standard of 1.5% of sales by 2020. This minimum is in addition to Minnesota's previously existing target, effectively raising the total percentage of required renewable generation for investor-owned utilities by 1.5%. Of the new solar mandate, 10% must be achieved via small systems that are 20 kilowatts or less. The bill also directs investor-owned utilities to design a "value of solar" tariff that could be used in lieu of a traditional retail rate-compensated net metering agreement.

Montana

Montana enacted several bills during 2013 related to the state's RPS [*27*]. Major changes include expanding the set of RPS-qualifying technologies to include generation from additional sources, such as: incremental capacity additions at existing hydropower projects; storage technologies such as flywheels, batteries, and hydroelectric pumped storage; and certain types of chemically treated biomass burned at small plants. Small utilities serving 50 or fewer customers are now exempt from the obligation to meet the state's RPS.

Table LR3-1. Renewable portfolio standards in the 29 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, hydro, landfill gas (LFG), anaerobic digestion built after January 1, 1997, geothermal	Direct use of solar heat, ground-source heat pumps, renewable-fueled combined heat and power (CHP), fuel cells	Credit trading is allowed, with some bundling restrictions. Includes distributed generation requirement, starting at 5% of target in 2007, growing to 30% by 2012 and beyond.
CA	33% by 2020	Solar, wind, biomass, geothermal, LFG and municipal solid waste (MSW), small hydro, biodiesel, anaerobic digestion, marine	Energy storage, fuel cells	Credit trading is allowed, with some restrictions. Renewable energy credit prices are capped at $50 per MWh.
CO	30% by 2020 for investor-owned utilities; 20% by 2020 for large electric cooperatives; 10% by 2020 for other cooperatives and municipal utilities serving more than 40,000 customers	Solar, wind, hydro, biomass, geothermal electric, anaerobic digestion, LFG	Recycled energy, coal-mine methane, pyrolysis gas produced from MSW, fuel cells	Credit trading is allowed. Renewable distributed generation requirement applies to investor-owned utilities (3% of sales by 2020) and electric cooperatives (0.75% or 1% of sales by 2020, depending on size). Generation associated with certain projects that have specific ownership or transmission ties with small utilities, entities, or individuals is eligible to earn credit multipliers.
CT	27% by 2020 (23% renewables, 4% efficiency and CHP)	Solar, wind, biomass, hydro (with exceptions), geothermal, LFG/MSW, anaerobic digestion and other biogas, marine	CHP, fuel cells	Credit trading is allowed. Obligated providers may comply via an alternative compliance payment of $55 per MWh. The target is made up of three class tiers, with tier-specific targets.
DE	25% by 2026	Solar, wind, biomass, hydro, geothermal, LFG, anaerobic digestion, marine	Fuel cells	Credit trading is allowed. Credit multipliers are awarded for several compliance specifications, including a 300% credit awarded for generation from in-state distributed solar and renewable-fueled fuel cells. Target increases for some suppliers can be subject to a cost threshold.
DC	20% by 2020	Solar, wind, biomass, hydro, geothermal, LFG/MSW, marine	Direct use of solar, cofiring, fuel cells	Credit trading allowed. The 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, efficiency programs, hydrogen, fuel cells	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, LFG	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 MW of eligible renewable resources	Solar, wind, some types of biomass and waste, small hydro, anaerobic digestion, LFG	None	Iowa's investor-owned utilities are currently in full compliance with this standard, achieved primarily through wind capacity.

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Table LR3-1. Renewable portfolio standards in the 29 states and District of Columbia with current mandates (cont.)

State	Target	Qualifying renewables	Qualifying other (thermal, efficiency, nonrenewable distributed generation, etc.)	Compliance mechanisms
KS	20% of each peak demand capacity by 2020	Solar, wind, hydro, biomass, LFG	Direct use of solar heat, fuel cells	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, wind, biomass, hydro, geothermal, LFG/MSW, marine, hydro	CHP, fuel cells	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, hydro	Solar water heating, ground-source heat pumps, fuel cells	Credit trading is allowed. The target includes minimum levels of compliance from solar and offshore wind. 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	Fuel cells	Credit trading is allowed. The target for new resources includes a solar-specific goal to achieve 400 MW 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. 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, coal with carbon capture and sequestration, energy efficiency measures for up to 10% of a utility's sales obligation	Credit trading is allowed. Solar power receives a credit multiplier; other generation and equipment features—such as peak generation, storage, and use of equipment manufactured in-state—can earn bonus credits.
MN	31.5% by 2020 (Xcel), 26.5% by 2025 (other investor-owned utilities), or 25% by 2025 (other utilities)	Solar, wind, hydro, biomass, LFG/MSW, anaerobic digestion	Cofiring, hydrogen	Credit trading is allowed. Target includes 1.5% solar standard for investor-owned utilities; Xcel's target also includes 25% of sales specifically from wind and solar (with a 1% maximum for solar). State regulators can penalize noncompliance at the estimated cost of compliance.
MO	15% by 2021, 0.3% of retail electricity sales from solar electricity by 2021	Solar, wind, hydro, biomass, LFG/MSW, anaerobic digestion, ethanol	Fuel cells	Credit trading is allowed. Noncompliance payments are set at double the market rate for renewables.
MT	15% by 2015	Solar, wind, hydro, geothermal, biomass, LFG, anaerobic digestion	Energy storage using renewable energy, fuel cells	Credit trading is allowed, with a price cap of $10 per MWh. There are specific targets for community-based projects.
NV	25% by 2025	Solar, wind, hydro, geothermal, biomass, LFG/MSW, biodiesel, anaerobic digestion	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. Solar PV receives a credit premium, with an additional premium for customer-sited systems.
NH	24.8% by 2025	Solar, wind, small hydro, marine, LFG, biomass, anaerobic digestion, certain biodiesel fuels	Fuel cells, CHP, microturbines, direct use of solar heat, ground-source heat pumps, hydrogen	Credit trading is allowed, and utilities may pay into a fund in lieu of holding credits. The target has four separate compliance classes, by technology type.

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Table LR3-1. Renewable portfolio standards in the 29 states and District of Columbia with current mandates (cont.)

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, anaerobic digestion	Fuel cells	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, biomass, anaerobic digestion	Zero-emission technology (not including nuclear), fuel cells	Credit trading is allowed. The program cannot increase consumer costs beyond a threshold amount, increasing to 3% of annual costs by 2015. Technology minimums are established for wind, solar, and certain other resources.
NY	29% by 2015	Solar, wind, hydro, biomass, LFG, anaerobic digestion, certain biofuels, marine	Direct use of solar heat, CHP, 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, anaerobic digestion	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, anaerobic digestion	Energy storage, fuel cells, and a separate 12.5% target for "advanced energy technologies," including coal mine methane, advanced nuclear, efficiency, clean coal	Credit trading is allowed. Alternative compliance payments are set by law and adjusted annually. There is a separate target for solar electricity generation.
OR	5% by 2025 for utilities with less than 1.5% of total sales; 10% by 2025 for utilities with at least 1.5% but less than 3% of total sales; 25% by 2025 for all others	Solar, wind, hydro, biomass, geothermal, LFG/MSW, anaerobic digestion, 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, geothermal, LFG/MSW, anaerobic digestion	CHP, certain advanced coal technologies, certain energy efficiency technologies, fuel cells, direct use of solar heat, ground-source heat pumps, other distributed generation technologies	Credit trading is allowed, with an alternative compliance payment. Separate targets are set for solar and two different combinations of renewable, fossil, and efficiency technologies.
RI	16% by 2019	Solar, wind, hydro, biomass, geothermal, anaerobic digestion, LFG, biodiesel, marine	Fuel cells	Credit trading is allowed, with an alternative compliance payment. There is a separate target for 90 MW of new renewable capacity.
TX	Enforceable target of 5,880 MW by 2015	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 MW must be from resources other than wind.

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Table LR3-1. Renewable portfolio standards in the 29 states and District of Columbia with current mandates (cont.)

State	Target	Qualifying renewables	Qualifying other (thermal, efficiency, nonrenewable distributed generation, etc.)	Compliance mechanisms
WA	15% by 2020	Solar, wind, hydro, biomass, geothermal, LFG, anaerobic digestion, biodiesel, marine	CHP	Credit trading is allowed, with an administrative penalty for noncompliance.
WI	10% by 2015	Solar, wind, hydro, biomass, geothermal, LFG/MSW, small hydro, anaerobic digestion, marine, biogas	CHP, pyrolysis, synthetic gas, direct use of solar or biomass heat, ground-source heat pumps, fuel cells	Credit trading is allowed.

Nevada

In June 2013 Nevada enacted Senate Bill 252 [*28*], which places new limits on the extent to which energy efficiency measures count toward the state's existing standard. The bill also restricts multiplier credits for customer-sited solar generation to installations placed in service before the end of 2015. The obligated utility, Nevada Energy, is also now required by Senate Bill 123 [*29*] to meet a capacity standard of 350 MW of new renewable capacity by the end of 2021. However, the same capacity can also be applied to the existing sales-based standard and thus does not necessarily require additional capacity beyond that which may have been required to meet the existing standard.

Washington

Washington enacted two bills—Senate Bills 5400 [*30*] and 5297 [*31*]—that increase compliance flexibility options for certain providers. Under Senate Bill 5400, utilities that serve customers in multiple states are now allowed to meet their obligations with sources from those states. Senate Bill 5297 allows for the use of "coal transition power" for compliance under very specific circumstances for utilities not experiencing load growth.

LR4. U.S. response to the nuclear accident at Fukushima Daiichi

Since the March 2011 accident at Japan's Fukushima Daiichi nuclear power plant, the U.S. Nuclear Regulatory Commission (NRC) and the U.S. nuclear industry have been working to address issues related to the accident. The NRC and the U.S. nuclear industry initiated an immediate coordinated response to the accident, as well as long-term actions intended to assure the safety of operating and planned reactors in the United States. The ultimate cost of complying with NRC orders and proposed regulations and industry-led initiatives remains uncertain, as do the potential impacts on nuclear power plant operations. Although they are not specifically modeled in AEO2014, NRC actions and industry initiatives are being monitored by EIA so that potential costs and operational impacts can be included in future AEOs.

The NRC conducted a systematic and methodical review of its own processes and regulations in light of the accident at Fukushima. On July 12, 2011, the NRC's Near-Term Task Force released its report, *Recommendations for Enhancing Reactor Safety in the 21st Century* [*32*]. The report contains 12 recommendations, including both short- and long-term actions for consideration, and prioritizes the implementation of the recommendations.

In order to address the short-term recommendations, the NRC issued three orders in March 2012 that require nuclear power plants to implement measures related to lessons learned from the Fukushima accident, as follows:

- All boiling-water reactors (BWRs) with Mark I and II containment systems must have reliable hardened containment venting capability to reduce pressure and hydrogen buildup. This may require improving or replacing existing containment ventilation systems [*33*].
- Reactors must have enhanced instrumentation installed to monitor water levels in their spent fuel pools in the event of an emergency [*34*].
- Nuclear power plants must be capable of responding to multiple simultaneous events and ensuring that reactors and spent fuel pools remain cooled. The order specifies a three-phase approach involving use of installed on-site resources, use of portable on-site equipment, and indefinite use of off-site resources [*35*].

The NRC stated that, in all cases, the existing fleet of reactors can continue operating safely while implementing the orders. The orders were effective immediately and included timetables for responses and actions.

In the three orders listed above, the NRC required an integrated plan to be submitted by February 2013, with initial status reports due in 60 days. The NRC specified that operating reactors must complete modifications within two refueling cycles after submitting an integrated plan, or by the end of 2016, whichever comes first. Any reactor with a construction permit issued under 10 CFR Part 50 (e.g., Watts Bar Unit 2) was required to comply with the above orders prior to receiving an operating license. Any reactor issued a Combined Operating License (COL) under 10 CFR Part 52 (i.e., Vogtle Units 3 and 4 and Summer Units 2 and 3) was required to implement all requirements in the orders before the initial fuel loading. Compliance assessments are underway at nuclear power plants. The requirements of the orders remain in place until superseded by other orders or rulemaking. As discussed below, NRC is considering or has initiated rulemaking on several topics, and some of the dates established in the original orders have been modified.

In November 2012, as an addition to the original order issued to address more robust containment venting systems, the NRC began considering whether to propose a rule that would require containment venting systems to filter all releases during an accident for boiling water reactors with Mark I and Mark II containments [*36*]. If the NRC decides to pursue such a rulemaking, a final rule could be issued in 2017 [*37*].

Utilities continue to provide documentation to the NRC on equipment procured to respond to a prolonged loss of power at a reactor (station blackout) as well as spent fuel pool water level monitoring instrumentation. In March 2013, the NRC decided to proceed with a rulemaking to address station blackout mitigation [*38*]. In its July 2013 regulatory basis document [*39*], the NRC noted: “One dual-unit site estimated that the order may cost approximately $25 million, while a second dual-unit site estimated the cost at $43 million.” The final rule is scheduled for issuance by December 2016.

By June 2013, two detailed inspections (or “walkdowns”) had been completed at each reactor to evaluate potential seismic and flooding hazards. The NRC is in the process of auditing the results of the walkdowns. All flooding re-evaluations are due to the NRC by March 2015 [*40*]. The NRC will review the analyses and issue a safety assessment for each site. For nuclear power plants requiring a seismic risk analysis, the NRC performed a prioritization of plants in the Central and Eastern United States (CEUS) and the Western United States (WUS). Plants in more seismically active WUS and CEUS locations will complete risk evaluations by June 2017, and those in less active CEUS locations will complete risk evaluations by December 2019 [*41*].

In November 2013, the NRC announced proposed rulemaking language to “. . . strengthen and integrate onsite emergency response capabilities.” [*42*] The final rule, which is likely to be issued in March 2016, is expected to address accident mitigation strategies; integration of accident mitigation procedures; identification of command and control roles during an accident; conduct of drills and exercises; training; and include severe accident situations in examinations for reactor operators. In its comments [*43*] on the NRC’s draft regulatory basis [*44*], the Nuclear Energy Institute (NEI) estimated a cost of $17 million for the nuclear fleet—or $275,000 per unit—to develop and implement new training plans. NEI also estimated increased training costs of $250,000 per site per year and annual severe accident drill costs of $250,000 per site.

In addition to the NRC actions described above, the Electric Power Research Institute (EPRI), the Institute of Nuclear Power Operations (INPO), and NEI formed a Fukushima Response Steering Committee to integrate and coordinate the industry’s response to the accident. In February 2012, the Steering Committee jointly released a report, *The Way Forward: U.S. Industry Leadership in Response to Events at the Fukushima Daiichi Nuclear Power Plant*, which discusses activities to oversee and coordinate responses to emergencies [*45*]. INPO prepared a detailed report on post-accident events at Fukushima Daiichi [*46*], and on November 11, 2011, the detailed report was provided to the U.S. Congress, the NRC, and the U.S. nuclear industry. The nuclear industry, through NEI, developed its FLEX strategy—a comprehensive, flexible, and integrated plan to mitigate the effects of severe natural phenomena and to take steps to achieve safety benefits quickly [*47*]. The FLEX approach, implemented in 2012, was informed by the industry’s response to the September 11, 2001, terrorist attacks in the United States. Two regional response centers will be located near Memphis, Tennessee, and Phoenix, Arizona. From those regional response centers, critical emergency equipment can be delivered to nuclear power plants within 24 hours. The regional response centers are planned to be fully operational by August 2014 [*48*].

In addition to activities that focus on reactors and the utilities that operate them, the NRC has spent more than two years evaluating how best to respond to the first of the 12 recommendations made in the July 2011 *Near-Term Task Force Review of Insights from the Fukushima Dai-Ichi Accident* [*49*], which recommended establishment of a “logical, systematic, and coherent regulatory framework for adequate protection that appropriately balances defense-in-depth and risk considerations.” Defense-in-depth is a layered approach to safety that involves the use of multiple redundant and independent safety systems. NRC’s evaluation of this recommendation [*50*] was discussed publicly in January 2014 and included proposed actions on a policy statement that would detail, among other things, the decision criteria for ensuring adequate defense-in-depth. The proposed actions also identify the need to clarify the role of voluntary industry initiatives in the NRC regulatory process.

The ultimate cost to the nuclear industry of addressing Fukushima-related issues remains uncertain, as do the potential impacts on nuclear power plant operations. In a meeting with the NRC in April 2013, Dominion Energy estimated that the cost of post-Fukushima actions could be $30 to $40 million per unit and $180 to $240 million for its fleet of six units [*51*, *52*]. AEO2014 does not include potential post-Fukushima effects on nuclear capacity and generation, but costs and operational impacts will be monitored for inclusion in future AEOs as NRC actions and industry initiatives progress.

Endnotes for legislation and regulations

Links current as of January 2014

1. A complete list of the laws and regulations included in AEO2014 is provided in *Assumptions to the Annual Energy Outlook 2014*, Appendix A, http://www.eia.gov/forecasts/aeo/assumptions/pdf/0554(2014).pdf.
2. Regional Greenhouse Gas Initiative, "2012 Program Review" (New York, NY: February 7, 2013), http://www.rggi.org/design/program-review.
3. U.S. Government Printing Office, "Energy Policy Act of 2005, Public Law 109-58" (Washington, DC: August 8, 2005), http://www.gpo.gov/fdsys/pkg/PLAW-109publ58/pdf/PLAW-109publ58.pdf.
4. U.S. Government Printing Office, "Energy Independence and Security Act of 2007, Public Law 110-140," (Washington, DC: December 19, 2007), http://www.gpo.gov/fdsys/pkg/PLAW-110publ140/pdf/PLAW-110publ140.pdf.
5. Colorado State University, Center for the New Energy Economy, "State Renewable Portfolio Standards Hold Steady or Expand in 2013 Session" (Fort Collins, CO: 2013), http://www.aeltracker.org/graphics/uploads/2013-State-By-State-RPS-Analysis.pdf.
6. The nine participating RGGI states are Maine, New Hampshire, Vermont, Massachusetts, Rhode Island, Connecticut, New York, Delaware, and Maryland.
7. California Environmental Protection Agency, Air Resources Board, "Assembly Bill 32: Global Warming Solutions Act" (Sacramento, CA: September 27, 2006), http://www.arb.ca.gov/cc/ab32/ab32.htm.
8. U.S. Environmental Protection Agency, "Mercury and Air Toxics Standards (MATS)" (Washington, DC: last updated March 27, 2012), http://www.epa.gov/mats.
9. U.S. Energy Information Administration, *Assumptions to the Annual Energy Outlook 2013*, DOE/EIA-0554(2013) (Washington, DC: May 2013), http://www.eia.gov/forecasts/aeo/assumptions. Table 8.8 indicates how much of a plant's uncontrolled mercury emissions are removed by a specific configuration of environmental control equipment for a given coal type. The strategies used by coal plants to comply with the mercury, acid gases, and toxic metals are discussed in the documentation.
10. *White Stallion Energy Center, LLC, et al. v. United States Environmental Protection Agency*, USCA Case #12-1100 (January 22, 2013), http://www.4cleanair.org/Documents/AdminBriefMATS.pdf.
11. U.S. Environmental Protection Agency, "Clean Air Interstate Rule (CAIR)" (Washington, DC: December 19, 2012), http://www.epa.gov/cair/index.html#older.
12. Further details on the modeling strategies for MATS and CAIR can be found in the forthcoming report, *Assumptions to the Annual Energy Outlook 2014*, and the forthcoming *Electricity Market Module of the National Energy Modeling System Model Documentation 2014*.
13. United States Court of Appeals for the District of Columbia Circuit, *EME Homer City Generation, L.P., v. Environmental Protection Agency, et al.*, No. 11-1302 (decided August 21, 2012), http://www.cadc.uscourts.gov/internet/opinions.nsf/19346B280C78405C85257A61004DC0E5/$file/11-1302-1390314.pdf.
14. U.S. Environmental Protection Agency, *United States Environmental Protection Agency, et al., v. EME Homer City Generation, L.P., et al., Petition for a Writ of Certiorari*, http://www.epa.gov/airmarkets/airtransport/CSAPR/pdfs/EME_Homer_City_Pet.pdf.
15. U.S. Government Printing Office, "Energy Policy Act of 2005, Public Law 109-58" (Washington, DC: August 8, 2005), http://www.gpo.gov/fdsys/pkg/PLAW-109publ58/pdf/PLAW-109publ58.pdf.
16. U.S. Government Printing Office, "Energy Independence and Security Act of 2007, Public Law 110-140" (Washington, DC: December 19, 2007), http://www.gpo.gov/fdsys/pkg/PLAW-110publ140/pdf/PLAW-110publ140.pdf.
17. Does not include the RPS policy for Hawaii, because NEMS provides electricity market projections only for the contiguous lower 48 states.
18. More information about the Database of State Incentives for Renewables & Efficiency (DSIRE) can be found at http://www.dsireusa.org.
19. G. Barbose, "Renewable Portfolio Standards in the United States: A Status Update" (November 2013), http://emp.lbl.gov/sites/all/files/rps_summit_nov_2013.pdf.
20. Enumerations of state RPS policies may vary from source to source, as these policies vary significantly from state to state with no universal definition. Previous enumerations of 30 state RPS policies by EIA have included a policy in West Virginia that allows for several types of fossil generators to be built instead of renewable generators to meet the portfolio requirement. However, because EIA does not model this in the *Annual Energy Outlook* as an RPS, it is not included in the current enumeration.
21. Eligible technologies, and even the definitions of technologies or fuel categories, vary by state. For example, one state's definition of renewables may include hydropower while another's may not. Table LR-1 provides more detail on how the technology or fuel category is defined by each state.

22. Colorado State University, "State Renewable Portfolio Standards Hold Steady or Expand in 2013 Session," *Center for the New Energy Economy* (Fort Collins, CO: July 2013), http://www.aeltracker.org/graphics/uploads/2013-State-By-State-RPS-Analysis.pdf.

23. State of Colorado General Assembly, "Senate Bill 13-252" (June 5, 2013), http://www.leg.state.co.us/clics/clics2013a/csl.nsf/fsbillcont3/D1B329AEB8681D4D87257B3900716761?open&file=252_enr.pdf.

24. State of Connecticut General Assembly, "Senate Bill 1138" (June 5, 2013), http://www.cga.ct.gov/2013/ACT/PA/2013PA-00303-R00SB-01138-PA.htm.

25. State of Maryland General Assembly, "House Bill 226: Maryland Offshore Wind Energy Act of 2013" (April 2013), http://mgaleg.maryland.gov/2013RS/bills/hb/hb0226e.pdf.

26. State of Minnesota Legislature, "House Floor 729" (May 2013), https://www.revisor.mn.gov/laws/?id=85&year=2013&type=0.

27. State of Montana Legislature, "Summary of Energy and Telecommunications Legislation: 2013 Legislative Session" (2013), http://leg.mt.gov/content/Committees/Interim/2013-2014/Energy-and-Telecommunications/Committee-Topics/2013EnergyBills.pdf.

28. State of Nevada Legislature, "Senate Bill 252" (June 2013), http://www.leg.state.nv.us/Session/77th2013/Bills/SB/SB252_EN.pdf.

29. State of Nevada Legislature, "Senate Bill 123" (June 2013), http://www.leg.state.nv.us/Session/77th2013/Bills/SB/SB123_EN.pdf.

30. State of Washington Legislature, "Senate Bill 5400" (April 2013), http://apps.leg.wa.gov/documents/billdocs/2013-14/Pdf/Bills/Session%20Laws/Senate/5400-S.SL.pdf.

31. State of Washington Legislature, "Senate Bill 5297" (April 2013), http://apps.leg.wa.gov/documents/billdocs/2013-14/Pdf/Bills/Session%20Laws/Senate/5297.SL.pdf.

32. U.S. Nuclear Regulatory Commission, *Recommendations for Enhancing Reactor Safety in the 21st Century* (Washington, DC: July 12, 2011), http://pbadupws.nrc.gov/docs/ML1118/ML111861807.pdf.

33. U.S. Nuclear Regulatory Commission, *Issuance of Order to Modify Licenses with Regard to Reliable Hardened Containment Vents* (Washington, DC: March 12, 2012), http://www.oecd-nea.org/nsd/fukushima/documents/NRC12March2012OrderonHardenedContainmentVents.pdf.

34. U.S. Nuclear Regulatory Commission, *Order Modifying Licenses with Regard to Reliable Spent Fuel Pool Instrumentation (Effective Immediately)* (Washington, DC: March 12, 2012), http://pbadupws.nrc.gov/docs/ML1205/ML12056A044.pdf.

35. U.S. Nuclear Regulatory Commission, *Issuance of Order to Modify Licenses with Regard to Requirements for Mitigation Strategies for Beyond-Design-Basis External Events* (Washington, DC: March 12, 2012), http://pbadupws.nrc.gov/docs/ML1205/ML12054A735.pdf.

36. U.S. Nuclear Regulatory Commission, *Policy Issue Notation Vote: Consideration of Additional Requirements for Containment Venting Systems for Boiling Water Reactors with Mark I and Mark II Containments* (Washington, DC: November 26, 2012), http://www.nrc.gov/reading-rm/doc-collections/commission/secys/2012/2012-0157scy.pdf.

37. *Ibid*.

38. U.S. Nuclear Regulatory Commission, "Station Blackout Mitigation Strategies," *Federal Register*, Vol. 78, No. 141 (Washington, DC: July 23, 2013), pp. 44035-44036, http://www.gpo.gov/fdsys/pkg/FR-2013-07-23/pdf/2013-17660.pdf.

39. U.S. Nuclear Regulatory Commission, *Station Blackout Mitigation Strategies: Regulatory Basis Document* (Washington, DC: July 2013), http://pbadupws.nrc.gov/docs/ML1317/ML13171A061.pdf.

40. Nuclear Energy Institute, "White Paper: U.S. Government and Nuclear Energy Industry Response to the Fukushima Accident" (Washington, DC: October 2013), http://www.nei.org/CorporateSite/media/filefolder/Policy/Papers/Fukushimawhitepaper.pdf?ext=.pdf.

41. U.S. Nuclear Regulatory Commission, "Electric Power Research Institute Final Draft Report XXXXXX, 'Seismic Evaluation Guidance: Augmented Approach for the Resolution of Fukushima Near-Term Task Force Recommendation 2.1: Seismic,' as an Acceptable Alternative to the March 12, 2012, Information Request for Seismic Reevaluations" (Washington, DC: May 7, 2013), http://pbadupws.nrc.gov/docs/ML1310/ML13106A331.pdf.

42. U.S. Nuclear Regulatory Commission, "Onsite Emergency Response Capabilities," Federal Register (Washington, DC: November 15, 2013), https://www.federalregister.gov/articles/2013/11/15/2013-27449/onsite-emergency-response-capabilities.

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Figure and table sources

Links current as of January 2014

Figure LR3-1. Total qualifying renewable generation required for combined state renewable portfolio standards and projected total achieved, 2013-40: AEO2014 National Energy Modeling System, run REF2014.D102413A.

Table LR3-1. Renewable portfolio standards in the 29 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 State Incentives for Renewables & Efficiency (as of January 15, 2014), website www.dsireusa.org.

Issues in focus

Introduction

The "Issues in focus" section of the *Annual Energy Outlook* (AEO) provides in-depth discussions on topics of special significance, including changes in assumptions and recent developments in technologies for energy production and consumption. Selected topics from recent AEOs are listed in Table IF-1.

Selected quantitative results from the issues discussed in AEO2014 are available in Appendix D. The first topic updates a discussion included in a number of previous AEOs, comparing the Reference case projections with two cases based on different assumptions about the future course of existing energy policies: one assumes the elimination of sunset provisions for various energy tax credits that are scheduled to expire under current law; the other assumes—in addition to the elimination of sunset provisions on various tax credits—the extension or expansion of three existing policies: corporate average fuel economy (CAFE) standards, appliance standards, and building code improvements.

Other topics discussed in this section include:

- U.S. tight oil production trends and supply projections based on alternative assumptions and a methodology using well-level data aggregated to the county level
- Potential of liquefied natural gas as a freight locomotive fuel
- Impacts of demographic issues and travel behavior on light-duty vehicle (LDV) energy demand
- Impacts of lower natural gas prices on industrial production
- Implications of accelerated power plant retirements
- Variations in renewable electricity projections in AEO2014 cases
- Implications of lower growth in electricity demand.

Table IF-1. Key analyses from "Issues in focus" in recent AEOs

AEO2013	AEO2012	AEO2011
U.S. reliance on imported liquid fuels in alternative scenarios	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
Competition between coal and natural gas in the electric power sector	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
Nuclear power in AEO2013	Impacts of a breakthrough in battery vehicle technology	Potential efficiency improvements in alternative cases for appliance standards and building codes
Effect of natural gas liquids growth	Heavy-duty natural gas vehicles	Potential of offshore crude oil and natural gas resources
	Changing structure of the refining industry	Prospects for shale gas
	Changing environment for fuel use in electricity generation	Cost uncertainties for new electric power plants
	Nuclear power in AEO2012	Carbon capture and storage: Economics and issues
		Power sector environmental regulations on the horizon

Sources: U.S. Energy Information Administration, *Annual Energy Outlook 2013,* DOE/EIA-0383(2013) (Washington, DC: April 2013); U.S. Energy Information Administration, *Annual Energy Outlook 2012,* DOE/EIA-0383(2012) (Washington, DC: June 2012); and U.S. Energy Information Administration, *Annual Energy Outlook 2011,* DOE/EIA-0383(2011) (Washington, DC: April 2011).

IF1. No Sunset and Extended Policies cases

Two alternative cases are discussed in this section to provide insight into the sensitivity of the Reference case to scenarios, in which existing tax credits that have sunset dates are assumed not to sunset (No Sunset case), or other policies (i.e., CAFE standards, appliance standards, and building codes) are expanded beyond current provisions in combination with the elimination of the sunset dates on existing tax credits (Extended Policies case). 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 are likely to, or should, be changed. The cases examined here look only at federal laws or regulations and do not examine state laws or regulations.

The No Sunset and Extended Polices cases generally lead to lower estimates for overall delivered energy consumption, increased use of renewable fuels (particularly for electricity generation), reduced energy-related carbon dioxide (CO_2) emissions, lower energy prices, and lower government tax revenues.

Background

The AEO2014 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 the regulations 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 this definition of the Reference case supports a variety of further analysis, there may be interest in alternative cases that reflect updates or extensions of current laws and regulations that the AEO2014 Reference case excludes. 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.
- 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 Corporate Average Fuel Economy (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.

Analysis cases

The two cases prepared—the No Sunset case and the Extended Policies case—incorporate all the assumptions from the AEO2014 Reference case, except as identified below.

No Sunset case

The sunset provisions for tax credits are eliminated for renewable energy sources in the utility, industrial, and buildings sectors and for energy-efficient equipment in the buildings sector, including the following:

- The production tax credit (PTC) of 1.1 or 2.3 cents/kilowatthour (kWh), depending on the technology, and the 30% investment tax credit (ITC) available for wind, geothermal, biomass, hydroelectric, and landfill gas resources are extended indefinitely as opposed to expiring at the end of 2013.
- For solar power investments, a 30% ITC that is scheduled to revert to a 10% credit in 2016 is assumed to be extended indefinitely at 30%.
- In the buildings sector, personal tax credits for the purchase of energy-efficient and renewable equipment, including photovoltaics (PV), are assumed to be extended indefinitely, as opposed to ending in 2013 or in 2016, respectively, 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. The business ITC for solar systems is assumed to remain at 30% instead of reverting to 10%.
- In the industrial sector, the 10% ITC for combined heat and power (CHP), which is assumed to end in 2016 in the AEO2014 Reference case [*1*], is assumed in the No Sunset case to be preserved through 2040.
- The $1.01/gallon (nominal) subsidy for cellulosic ethanol and $1.00/gallon (nominal) biodiesel subsidy are assumed to be extended at those levels from their recent expiration at the end of 2013 through the end of the projection period [*2*].

Extended Policies case

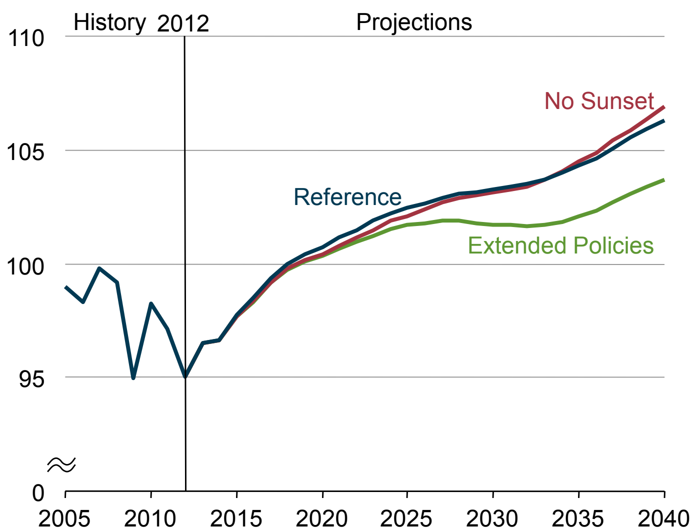
The Extended Policies case includes additional updates to federal equipment efficiency standards that were not considered in the Reference case or the No Sunset case. Residential and commercial end-use technologies eligible for incentives in the No Sunset case are not subject to new standards. Other than those exceptions, the Extended Policies case adopts the same assumptions as the No Sunset case, in addition to 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 also are introduced for products that are not currently subject to federal efficiency standards.
- Federal energy codes for residential and commercial buildings are assumed to be updated periodically, providing additional improvement to new construction. 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 AEO2014 Reference, No Sunset, and Extended Policies cases include the joint attribute-based CAFE and vehicle GHG emissions standards for model year (MY) 2012 to MY 2025 for light-duty vehicles (LDVs). 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 at an annual average rate of 1.3% for new LDVs after MY 2025.
- The AEO2014 Reference, No Sunset, and Extended Policies cases include the heavy-duty vehicle (HDV) fuel consumption and GHG emissions standards for MY 2014 to MY 2018. The Reference and No Sunset cases assume that the standards are held constant at MY 2018 levels in subsequent model years, although the fuel economy of HDVs rises modestly thereafter. The Extended Policies case includes an increase in fuel consumption and GHG emissions standards for 13 vehicle size classes.
- In the industrial sector, the ITC for CHP is extended to cover all properties with CHP, no matter what the system size (which may include multiple units), instead of being limited to properties with systems smaller than 50 megawatts (MW) as in the Reference case [*3*]. Also, the ITC is modified to increase the eligible CHP unit cap from 15 MW to 25 MW. These extensions are consistent with previously proposed legislation.
- The extension of ethanol and biodiesel subsidies assumed in the No Sunset case is not included in the Extended Policies case, because the renewable fuel standard (RFS) program already included in the AEO2014 Reference case tends to determine the levels of ethanol and biodiesel use.

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 delivered 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 of the No Sunset case (with some exceptions discussed below). Both cases result in lower energy prices, because the assumed tax credits and end-use efficiency standards lead to lower energy demand (except in the No Sunset case after 2034, as discussed below) and lower costs for 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.

Figure IF1-1. Total energy consumption in three cases, 2005-40 (quadrillion Btu)



Energy consumption

Total energy consumption in the No Sunset case is slightly lower than in the Reference case before 2034 and slightly higher than in the Reference case in the later years of the projection (Figure IF1-1). Improvements in energy efficiency lead to reduced consumption in the No Sunset case, but the demand-increasing effect of lower energy prices fully offsets the efficiency impacts by the end of the projection period. In 2040, total energy consumption in the Extended Policies case is 2% below the Reference case projection, as the combination of tax and other policy extensions reduces overall demand even after taking price declines into account.

Buildings energy consumption

Renewable distributed generation (DG) technologies (photovoltaic systems and small wind turbines) provide much of the buildings-related energy savings in the No Sunset case. The continuation of tax credits in the No Sunset case spurs increased adoption of DG systems, leading to 59 billion kWh of onsite electricity generation from renewable DG in 2025, compared with 25 billion kWh in the Reference case. In 2040, onsite electricity generation from renewable sources increases to 145 billion kWh in the No Sunset case—almost three times the amount of onsite electricity generated in the Reference case in that year.

Similar adoption of renewable DG occurs in the Extended Policies case, while efficiency gains from assumed future standards and more stringent building codes further reduce delivered energy use in the buildings sectors. Delivered energy use for buildings in the Extended Policies case is 1.5%, or 0.3 quadrillion British thermal units (Btu), lower than in the Reference case in 2025 and 5.4%, or 1.1 quadrillion Btu, lower than in the Reference case in 2040. In the No Sunset case, in contrast, delivered energy consumption is only 1.0% (0.2 quadrillion Btu) and 1.8% (0.4 quadrillion Btu) lower than in the Reference case projections for 2025 and 2040, respectively.

Electricity use shows the largest reduction in the two alternative cases relative to the Reference case. Building electricity purchases in 2025 are 1.4% and 1.9% lower in the No Sunset and Extended Policies cases, respectively, and 2.8% and 6.9% lower, respectively, in 2040, when compared with the Reference case. Increased onsite generation decreases electricity purchases in both cases. Additional reductions in electricity purchases occur in the Extended Policies case, as assumed standards increase the market penetration of efficient equipment and building construction. Energy use for water heating in the Extended Policies case shows the largest drop relative to the Reference case, at 16% (0.4 quadrillion Btu) below the Reference case level in 2040. Space heating and cooling also are affected by the assumed standards for equipment and building codes in the Extended Policies case, and energy consumption for those uses is reduced by a combined 6.7% (0.5 quadrillion Btu) from the Reference case level in 2040. In 2040, natural gas use in the buildings sectors is 0.9% and 4.1% below the Reference case level in the No Sunset and Extended Policies cases, respectively.

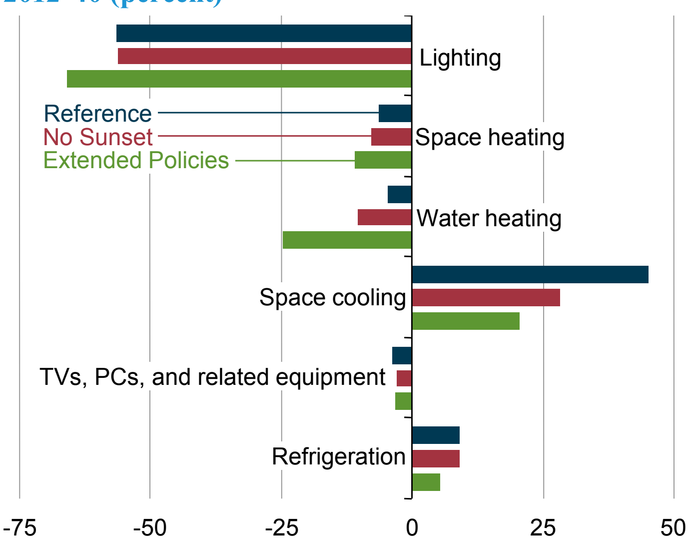
Residential energy consumption for most end uses moves in the same direction in all three cases, but at different rates (Figure IF1-2). For example, energy use for lighting, which declines in the Reference case, declines further in the Extended Policies case with additional standards; and space cooling, which increases in the Reference case, increases more slowly in the No Sunset case, which assumes the continuation of tax credits for efficient equipment and building shell thermal integrity improvement.

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, while raising the system size limit for the maximum credit that can be claimed, from 15 MW of installed capacity to 25 MW. The changes result in 1.2 gigawatts (GW) of additional industrial CHP capacity in the Extended Policies case compared with the Reference case in 2025 and 3 GW of additional capacity in 2040.

From 2025 through 2040, more CHP capacity is installed in the Extended Policies case than in the No Sunset case, but the differences narrow over time. CHP capacity is 0.3 GW higher in the Extended Policies case than in the No Sunset case in 2025, but only 0.1 GW higher in 2040. The Extended Policies case includes a tax benefit that applies to more CHP units than in the No Sunset case, which by itself provides greater incentive to build CHP capacity. However, electricity prices are slightly lower in the Extended Policies case than in the No Sunset case starting around 2024, and the difference grows over time, which reduces the economic attractiveness of CHP. These opposite effects explain why CHP capacity in the Extended Policies case is only slightly higher than in the No Sunset case, and why the difference decreases over time. Also, the median size of the nameplate capacity of industrial CHP units is 10 MW [*4*], and most CHP systems are well within the 50-MW 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.

Figure IF1-2. Change in residential delivered energy consumption for selected end uses in three cases, 2012-40 (percent)



Natural gas consumption in the industrial sector averages 10.4 quadrillion Btu per year from 2012 to 2040 in all three cases. However, the pattern of use varies, with the No Sunset and Extended Policies cases showing higher levels of consumption than the Reference case at the end of the projection period.

Transportation energy consumption

The Extended Policies case differs from the Reference and No Sunset cases in assuming that the joint CAFE and greenhouse gas emissions standards promulgated by EPA and NHTSA for model years 2012 through 2025 are extended through 2040, with an assumed average annual increase of 1.3%. Sales of vehicles that do not rely solely on gasoline internal combustion engines for power (including those that use

Effects of proposed energy provisions in the Energy Savings and Industrial Competitiveness Act of 2013

Senate bill S. 1392, The Energy Savings and Industrial Competitiveness Act of 2013 (ESICA) [5], introduced in July 2013, contains provisions for building energy codes, industrial energy efficiency, federal agencies, and budget offsets. Assuming appropriation of the funding authorized in the bill, EIA examined two key provisions of the proposed legislation: the adoption of updated building energy codes for residential and commercial buildings, and a rebate program for energy-efficient electric motors [6]. Other provisions require further specification by federal agencies or Congress, or they address levels of detail beyond that modeled in the National Energy Modeling System. Amendments have been introduced that may have energy impacts, but they are not part of the bill as of this writing and are not considered in this analysis. Of the two provisions analyzed for AEO2014, the updated building codes have a small effect on energy consumption and CO_2 emissions, and the industrial motors rebate program has virtually no effect. The analysis assumes that states will take advantage of incentives offered to implement the updated codes, and that once in place the codes will be effective over time.

Compared with the AEO2014 Reference case, the proposed building codes in ESICA reduce buildings delivered energy consumption by 0.7% in 2025 and 1.1% in 2040. Natural gas shows the largest reduction in buildings' energy use relative to the Reference case, as improved building shells lessen space heating requirements. Lower energy use in the ESICA case leads to lower levels of CO_2 emissions than in the Reference case. From 2014 to 2040, energy-related CO_2 emissions are reduced by a cumulative total of 307 million metric tons (an annual average of about 12 million metric tons) relative to the Reference case projection.

Residential and commercial consumers save $9.2 billion (2012 dollars) on energy purchases in 2040 in the ESICA case relative to the Reference case, as a result of lower energy demand. From 2014 to 2040, the cumulative reduction in residential and commercial energy purchases in the ESICA case totals $96.9 billion. Some of those savings are assumed to be offset by additional costs to the buildings sectors in meeting more stringent building codes, but such costs are not comprehensively modeled by EIA. The electric motor rebate program has a minimal impact on energy use, because the proposed program is limited in terms of both authorized funding and the two-year time frame for eligible installations.

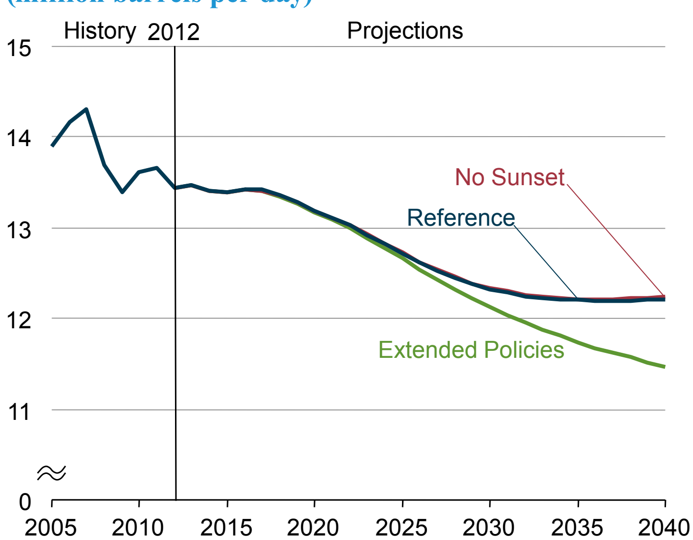
diesel, alternative fuels, or hybrid electric systems) play a substantial role in meeting the higher fuel economy standards after 2025, growing to 76% of new light-duty vehicle (LDV) sales in 2040, compared with 55% in the Reference case.

LDV energy consumption declines from 16.0 quadrillion Btu (8.7 million barrels per day [MMBbl/d] of oil equivalent) in 2012 to 13.5 quadrillion Btu (7.4 million barrels per day (MMBbl/d) of oil equivalent) in 2025 in the Reference case 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 11.1 quadrillion Btu (6.1 MMBbl/d of oil equivalent) in 2040, which is 9% lower than in the Reference case.

The Extended Policies case differs from the Reference and No Sunset cases by extending the standards for heavy-duty vehicle (HDV) fuel consumption and GHG emissions after MY 2018. New HDV fuel economy increases from 7.7 mpg in 2018 to 8.0 mpg in 2040 in the Extended Policies case. HDV annual energy consumption still rises from 5.3 quadrillion Btu (2.5 MMBbl/d of oil equivalent) in 2012 to 6.0 quadrillion Btu (2.9 MMBbl/d of oil equivalent) in 2018 and continues to grow to 7.3 quadrillion Btu (3.5 MMBbl/d of oil equivalent) in 2040 in the Extended Policies case. However, the total is lower than the 7.5 quadrillion Btu (3.6 MMBbl/d of oil equivalent) in the Reference case in 2040.

Consumption of petroleum and other liquids in the transportation sector is nearly the same through 2025 in the Reference and Extended Policies cases but declines in the Extended Policies case from 12.7 MMBbl/d of oil equivalent in 2025 to 11.5 MMBbl/d of oil equivalent in 2040, as compared with 12.2 MMBbl/d of oil equivalent in 2040 in the Reference case (Figure IF1-3).

Figure IF1-3. Consumption of petroleum and other liquids for transportation in three cases, 2005-40 (million barrels per day)



Renewable electricity generation

The No Sunset and Extended Policies cases assume that tax credits for renewable electricity generation sources are extended through 2040, resulting in significantly more renewable generation—primarily from wind and solar—than in the Reference case in 2040 (Figure IF1-4). In general, renewable generation in the No Sunset case is slightly higher than in the Extended Policies case, which includes energy efficiency measures that result in slower load growth and lower demand for new generation capacity.

In the Extended Policies case, wind generation more than triples from 2012 to 2040, compared with a 76% increase in the Reference case. However, the short-term growth of wind generation in the Reference case exceeds that in the Extended Polices case, as qualification for the current production tax credit (PTC) requires that new wind capacity be under construction by 2013 and generally in service before 2016, resulting in a near-term surge in wind capacity additions.

Minimal demand for new capacity and competitive natural gas prices limit mid-term (approximately 2015 to 2025) wind growth in all the cases, but long-term sustained growth of wind generation capacity begins earlier (in the early 2020s) and proceeds at more rapid rate in the Extended Policies case as a result of relative attractiveness of wind projects under the continued support of the PTC.

Solar generation grows at a uniformly higher rate in the Extended Policies case than in the Reference case, in response to the assumed extension of the solar investment tax credits (ITC) in the Extended Policies case that either expire or are significantly reduced after 2016 in the Reference case. In both the No Sunset and Extended Polices cases, total U.S. solar generation increases by an average of about 12% per year from 2012 to 2040, compared with 7% per year in the Reference case. In general, the relatively higher growth benefits both utility-scale PV installations in the electric power sector and customer-sited rooftop PV applications in the residential and commercial sectors. The effects of tax credit extensions on other renewable generation technologies, such as hydropower, biomass, and geothermal, are minimal in comparison.

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 2012 to 2040, energy-related CO_2 emissions are reduced by a cumulative total of 2.6 billion metric tons (a 1.7% reduction over the period) in the Extended Policies case relative to the Reference case, as compared with 1.2 billion metric tons (a 0.7% reduction over the period) in the No Sunset case (Figure IF1-5). The increase in fuel economy standards assumed for new LDVs in the Extended Policies case is responsible for 11.4% of the total cumulative reduction in CO_2 emissions from 2012 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 the Extended Policies case, 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 shows reduced emissions as a result of lower petroleum use.

Energy prices and tax credit payments

With lower natural gas use and more consumption of renewable fuels stimulated by tax credits in the No Sunset and Extended Policies cases, natural gas and electricity prices are lower than in the Reference case. In 2040, the average delivered price for natural gas is \$0.44/thousand cubic feet (Mcf), or 4.2%, lower in the No Sunset case and \$0.48/Mcf, or 4.5%, lower in the Extended Policies case than in the Reference case (Figure IF1-6). Similarly, average end-use electricity prices are 0.46 cents/kWh

Figure IF1-4. Renewable electricity generation in three cases, 2012, 2020, 2030, and 2040 (billion kilowatthours)

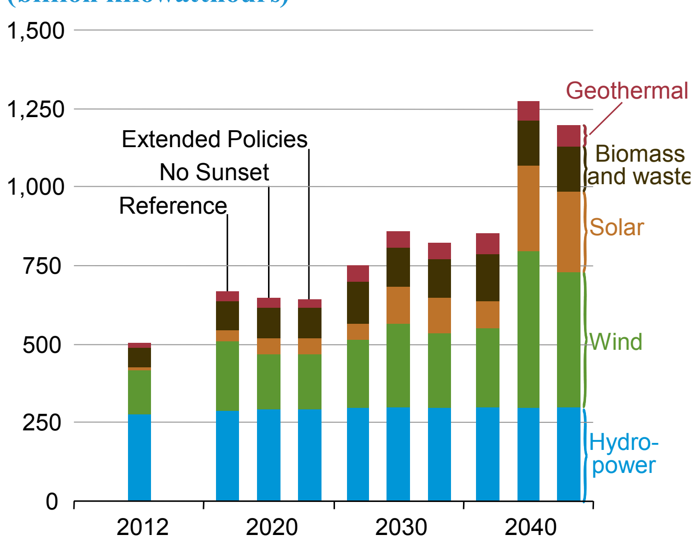
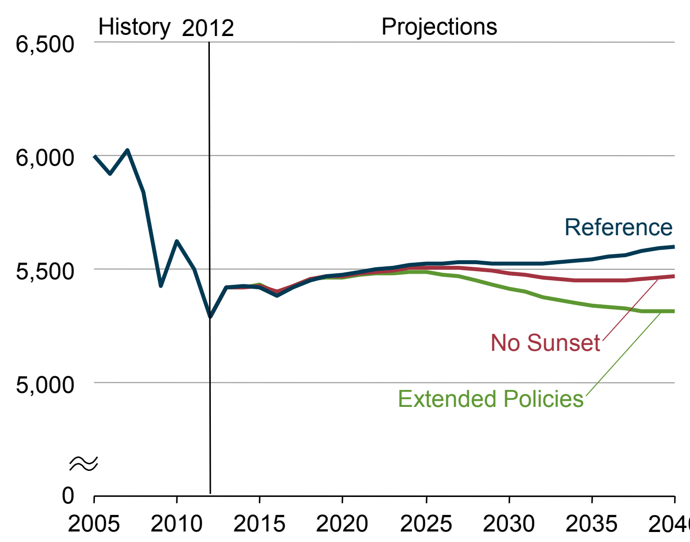


Figure IF1-5. Energy-related carbon dioxide emissions in three cases, 2005-40 (million metric tons)



(4.1%) lower in the No Sunset case and 0.55 cents/kWh (5.0%) lower in the Extended Policies cases than in the Reference case (Figure IF1-7).

The reductions in delivered energy consumption and CO_2 emissions in the No Sunset and Extended Policies cases are accompanied by higher equipment costs for consumers and revenue reductions for the U.S. government. Compared to the Reference case, residential and commercial consumers in the No Sunset case, on average, pay an extra $1.7 billion/year (2012 dollars) for end-use equipment, residential building shell improvements, and additional distributed generation systems between 2014 and 2040. The government, on average, pays an extra $7.7 billion/year in tax credits to consumers in the buildings sector (or, from the government's perspective, receives that amount of reduced revenue). In the Extended Policies case, consumers and the government pay, on average, an additional $14.5 billion and $5.1 billion/year, respectively, over the amounts in the Reference case between 2014 and 2040.

The additional costs to the buildings sectors in the No Sunset and Extended Policies cases are more than offset by savings on energy purchases as a result of efficiency improvements and increased distributed generation. Compared to the Reference case, residential and commercial consumers save an average of $11.9 billion (2012 dollars) in annual energy costs from 2014 to 2040 in the No Sunset case and an average of $20.4 billion annually in the Extended Policies case.

The largest response to federal tax incentives for new renewable generation in the power sector is seen in the No Sunset case, where the extension of the PTC and the 30% ITC reduces government tax revenues by approximately $4.5 billion/year from 2014 to 2040, as compared with $483 million/year in the Reference case. In the Extended Policies case, the reduction in government tax revenues is similar to, but somewhat less than, that in the No Sunset case because of the lower levels of demand. From 2014 to 2040, annual government tax revenues in the Extended Policies case will be approximately $3.3 billion/year lower than in the Reference case.

Figure IF1-6. Average delivered prices for natural gas in three cases, 2005-40 (2012 dollars per thousand cubic feet)

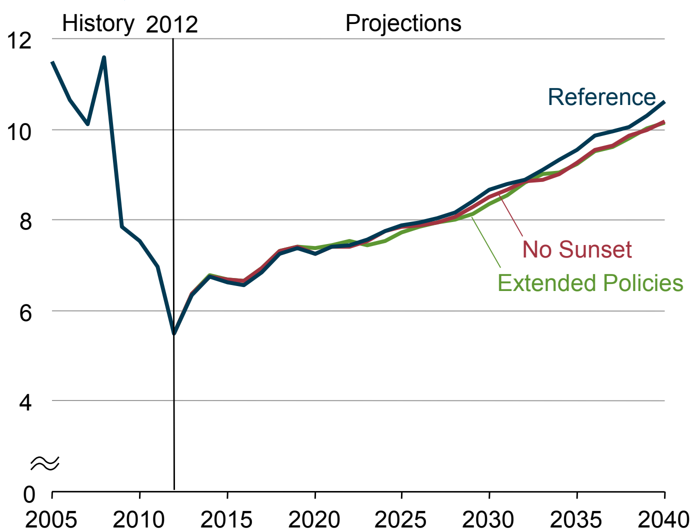
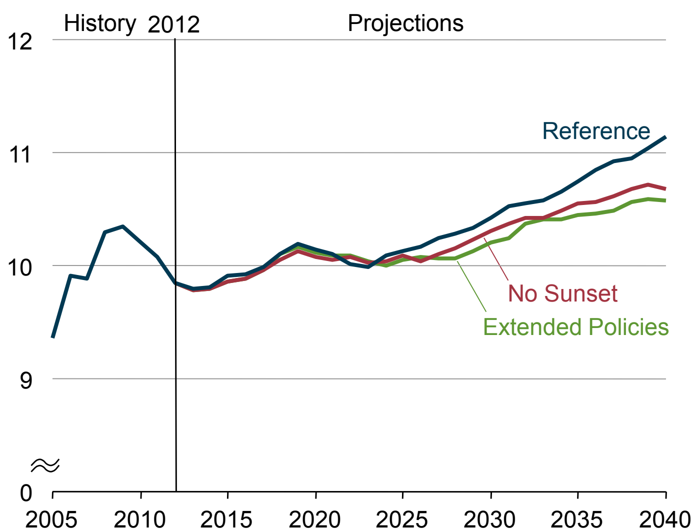


Figure IF1-7. Average electricity prices in three cases, 2005-40 (2012 cents per kilowatthour)



Endnotes for IF1

Links current as of April 2014

1. United States Internal Revenue Code, Title 26, Subtitle A—Income Taxes, §48(a)(2)(A)(ii), http://www.gpo.gov/fdsys/pkg/USCODE-2011-title26/pdf/USCODE-2011-title26-subtitleA-chap1-subchapA.pdf.
2. A tax extenders package that includes a two-year extension of the biodiesel credit (retroactive to January 1, 2014) was passed by the Senate Finance Committee on April 3, 2014, but still must be passed by the House and the full Senate to become law. R. Kotrba, "Senate Finance Committee passes tax package with biodiesel credit," *Biodiesel Magazine* (April 3, 2014), http://biodieselmagazine.com/articles/41973/senate-finance-committee-passes-tax-package-with-biodiesel-credit.
3. United States Internal Revenue Code, Title 26, Subtitle A—Income Taxes, §48(c)(3)(B)(iii), http://www.gpo.gov/fdsys/pkg/USCODE-2011-title26/pdf/USCODE-2011-title26-subtitleA-chap1-subchapA.pdf.
4. Calculations based on U.S. Energy Information Administration, Form EIA-860, Schedule 3, 2011 data (Washington, DC, January 9, 2013), http://www.eia.gov/electricity/data/eia860/index.html.
5. U.S. Congress, "S. 1392 - Energy Savings and Industrial Competitiveness Act of 2013," http://beta.congress.gov/bill/113th-congress/senate-bill/1392?q={%22search%22:[%22S.%201392%22]}.
6. Modeled provisions based on S. 1392, Sections 101 and 221, as brought to the Senate floor in September 2013. An updated version of the bill was reintroduced on February 27, 2014, http://beta.congress.gov/bill/113th-congress/senate-bill/2074/text. As of this writing, time had not been scheduled for Senate floor discussion.

Figure sources for IF1

Links current as of April 2014

Figure IF1-1. Total energy consumption in three cases, 2005-40: History: U.S. Energy Information Administration, *Monthly Energy Review September 2013,* DOE/EIA-0035 (2013/09) (Washington, DC, September 2013). **Projections:** AEO2014 National Energy Modeling System, runs REF2014.D102413A, NOSUNSET.D121713A, and EXTENDED.D022814A.

Figure IF1-2. Change in residential delivered energy consumption for selected end uses in three cases, 2012-40: History: U.S. Energy Information Administration, *Monthly Energy Review September 2013,* DOE/EIA-0035 (2013/09) (Washington, DC, September 2013). **Projections:** AEO2014 National Energy Modeling System, runs REF2014.D102413A, NOSUNSET.D121713A, and EXTENDED.D022814A.

Figure IF1-3. Consumption of petroleum and other liquids for transportation in three cases, 2005-40: History: U.S. Energy Information Administration, *Monthly Energy Review September 2013,* DOE/EIA-0035 (2013/09) (Washington, DC, September 2013). **Projections:** AEO2014 National Energy Modeling System, runs REF2014.D102413A, NOSUNSET.D121713A, and EXTENDED.D022814A.

Figure IF1-4. Renewable electricity generation in two cases, 2012-40: History: U.S. Energy Information Administration, *Monthly Energy Review September 2013,* DOE/EIA-0035 (2013/09) (Washington, DC, September 2013). **Projections:** AEO2014 National Energy Modeling System, runs REF2014.D102413A, NOSUNSET.D121713A, and EXTENDED.D022814A.

Figure IF1-5. Energy-related carbon dioxide emissions in three cases, 2005-40: History: U.S. Energy Information Administration, *Monthly Energy Review September 2013,* DOE/EIA-0035(2013/09) (Washington, DC, September 2013). **Projections:** AEO2014 National Energy Modeling System, runs REF2014.D102413A, NOSUNSET.D121713A, and EXTENDED.D022814A.

Figure IF1-6. Average delivered prices for natural gas in three cases, 2005-40: History: U.S. Energy Information Administration, *Monthly Energy Review September 2013,* DOE/EIA-0035(2013/09) (Washington, DC, September 2013). **Projections:** AEO2014 National Energy Modeling System, runs REF2014.D102413A, NOSUNSET.D121713A, and EXTENDED.D022814A.

Figure IF1-7. Average electricity prices in three cases, 2005-40: History: U.S. Energy Information Administration, *Monthly Energy Review September 2013,* DOE/EIA-0035(2013/09) (Washington, DC, September 2013). **Projections:** AEO2014 National Energy Modeling System, runs REF2014.D102413A, NOSUNSET.D121713A, and EXTENDED.D022814A.

IF2. U.S. tight oil production: Alternative supply projections and an overview of EIA's analysis of well-level data aggregated to the county level

U.S. production of tight oil has increased dramatically in the past few years, from less than 1 million barrels per day (MMbbl/d) in 2010 to more than 3 MMbbl/d in the second half of 2013 [*1*]. The *Annual Energy Outlook 2014* (AEO2014) Reference case reflects continued growth in tight oil production. However, growth potential and sustainability of domestic crude oil production hinge around uncertainties in key assumptions, such as well production decline, lifespan, drainage areas, geologic extent, and technological improvement—both in areas currently being drilled and in those yet to be drilled. As a result, High and Low Oil and Gas Resource cases were developed to examine the effects of alternate resource and technology assumptions on production, imports, and prices.

The projected trends in oil production vary tremendously in the alternative cases, and those trends hold important implications for the United States. In the High Oil and Gas Resource case, growth in tight oil production continues for a longer period of time than projected in the Reference case. Domestic crude oil production increases to nearly 13 MMbbl/d before 2035 in the High Oil and Gas Resource case, and net U.S. oil imports decline through 2036 and remain at or near zero from 2037 through 2040. The Low Oil and Gas Resource case reflects uncertainty about tight oil and shale crude oil and natural gas resources that leads to lower domestic production than in the Reference case. In this case, production reaches 9.1 MMbbl/d in 2017 before falling to 6.6 MMbbl/d in 2040, leading to higher projected dependence on net imports of petroleum and other liquids than in the Reference case. The range of production and imports in these alternative cases, as shown in Figures IF2-1 and IF2-2, illustrates the importance of uncertainty in the resource and technology assumptions.

Policymakers, industry, markets, and the public have great interest in the outlook for future domestic oil production and its key drivers. EIA continues to advance both the quality and transparency of its work in this area. Improvements made to the National Energy Modeling System (NEMS) Oil and Gas Supply Module for AEO2014 enhance its ability to capture rapid growth in tight oil production. Specifically, EIA has implemented a more disaggregated representation of estimated ultimate recovery (EUR) that uses well-level data aggregated to the county level within key producing regions to track the combined effect of technology advances and the changing quality of resources being targeted on production per well, which in turn drives an analysis of EUR for wells in each region. There is still a great deal of uncertainty in the projections of U.S. tight oil production. EIA's analysis reflects those uncertainties by varying key assumptions regarding the resource base and the rate of technology advances that lower drilling cost or raise its productivity across alternative cases. As new information is gained through drilling, production, and technology experimentation, NEMS projections for tight oil production will continue to evolve.

Improvements in data collection and projections

The domestic oil supply outlook in AEO2014 is based on data derived from measurements at production sites that are available for analysis. Those data provide a basis for improved understanding of the key factors that have contributed to the growth of tight oil production, which has improved the analysis in AEO2014; however, limitations about the use of the data should be taken into account when the Reference case results are examined.

As individual production profiles of wells drilled in tight oil formations are developed and analyzed, they provide a basis for the calculation of a production decline curve and EUR for each well. The results can be used to project potential future production from existing wells and from new wells drilled in the same plays [*2*].

Figure IF2-1. U.S. crude oil production in three cases, 1960-2040 (million barrels per day)

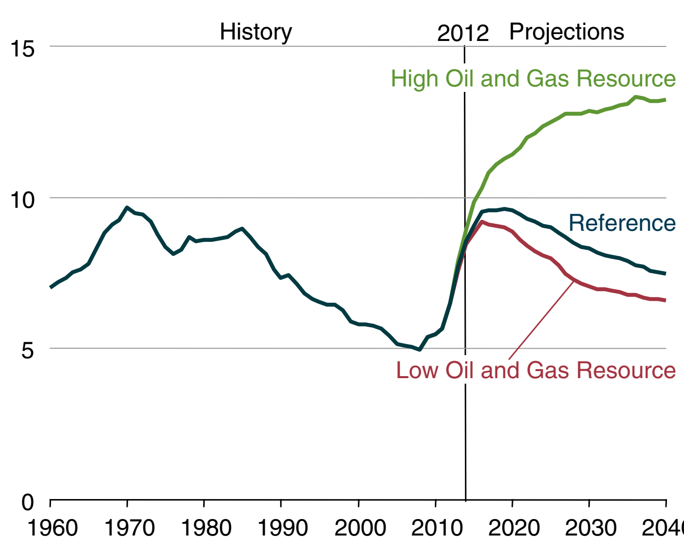
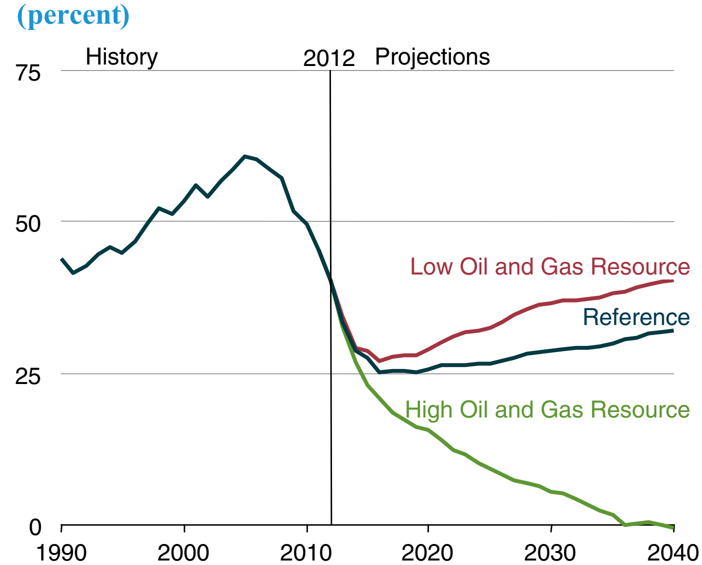


Figure IF2-2. Net import share of U.S. petroleum and other liquids consumption in three cases, 1990-2040 (percent)



Production decline curves and the associated EURs for individual wells vary widely across plays, within single plays, and even within discrete sections (counties) of a single play. Using the Eagle Ford formation in Texas as an example, the discussion below examines the methods used to estimate EURs for tight oil wells, the distribution of EURs, the factors that contribute to variations in EURs, and the implications of using county-level representations as the basis for projections of overall production totals both for oil and for natural gas, which is often a coproduct of tight oil production. Uncertainties related to EUR estimation and advances in tight oil production technologies, and their effects on projections of domestic tight oil production in the AEO2014 High and Low Oil and Gas Resource cases, are explored by scaling production decline curves.

Estimating ultimate recovery per well

For each tight well or shale well with initial production in 2008 or later, and with at least four months of production data available, the U.S. Energy Information Administration (EIA) fits monthly production to a decline curve. The mathematical form of the curve is initially hyperbolic [*3*], but it shifts to exponential when the annual decline rate reaches 10% [*4*]. The EUR is the sum of actual past production from the well, as reported in the data, and an estimate of future production based on the fitted production decline curve over a 30-year well lifetime.

The actual production curve and the resulting actual ultimate recovery are highly uncertain and cannot be known until the well is plugged and abandoned, which may occur sooner or later than 30 years. Estimates of future production based on the first few months of initial production can differ significantly from later estimates for the same well.

As more months of production are added, the shape of the production curve and the resulting EUR for a given well can change. For example, for one well drilled in Live Oak County in the Eagle Ford formation in Texas, fitting a curve to the first year of monthly production data gave a EUR of 574,000 barrels; using four years of production data gave a EUR of 189,000 barrels for the same well. Conversely, another well in the same county had a EUR of 105,000 barrels based on the first 12 months of production data but 224,000 barrels based on four years of monthly production data. For the wells in the Eagle Ford formation with at least four years of production, EURs based on only the first year of monthly production ranged from as much as 385,000 barrels higher to 173,000 barrels lower than the EURs based on four years of production. Generally, the EUR stabilizes after three years of production, because for many wells in tight formations nearly 50% of the EUR has been produced during that period. EURs based on three years of data differ from EURs based on four years of data by 6,000 barrels on average, with a range of 65,000 barrels higher to 98,000 barrels lower. Because most Eagle Ford wells have been producing for less than three years (Table IF2-1), their EURs are likely to change as more production history is added.

County-level representation

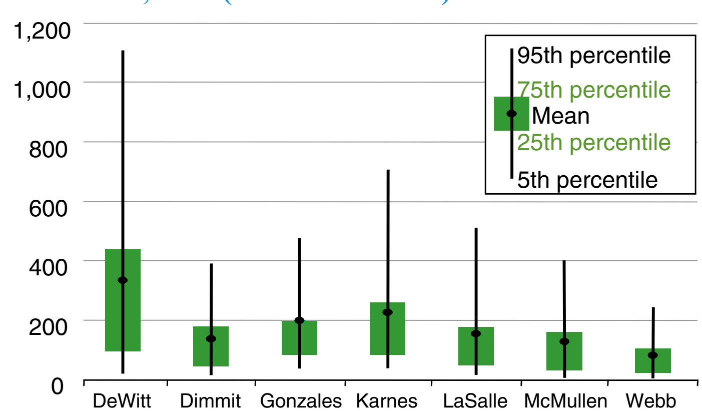
The decline curves from all wells in each county, averaged by production month, are used to generate a representative production curve that provides a basis for estimating production from future wells in that county. Wells that are newly drilled, with fewer data points and therefore greater uncertainty in the fit of their decline curves, have a tendency to inflate the average EUR. Older wells, which may have been drilled and completed using technologies and practices that are no longer representative of future practices, tend to pull the average down.

The range of EURs within a given county can be large, as shown in Figure IF2-3 for the seven counties in the Eagle Ford formation that have more than 400 oil and natural gas wells. Some wells have high initial production, but because they have been producing for less than a year, their EURs are highly uncertain. These few high-performing wells raise the county mean EUR above the county median EUR, generally skewing the mean toward the 75th percentile.

Table IF2-1. Average estimated ultimate recovery for wells in the Eagle Ford formation starting production between January 2008 and June 2013 and with at least four months of production

Vintage year	Number of wells	Average EUR (thousand barrels)
2008	33	36
2009	75	57
2010	514	117
2011	1,627	153
2012	2,717	191
2013	418	169
All years	**5,384**	**168**

Figure IF2-3. Distribution of estimated ultimate recovery per well in seven counties in the Eagle Ford formation, 2013 (thousand barrels)



	DeWitt	Dimmit	Gonzales	Karnes	LaSalle	McMullen	Webb
Mean EUR	334	137	198	226	153	127	80
Number of wells	453	820	486	975	755	455	593

The Eagle Ford formation covers 32 counties in Texas. In 14 of those counties, fewer than 10 wells had been drilled as reported through June 2013. The EUR for counties with little or no drilling is assumed to be equal to the average of the mean estimates from adjacent counties [5]. The Eagle Ford county-level EURs range from more than 300,000 barrels per well (DeWitt county) to less than 25,000 barrels per well (Burleson and Maverick counties), with a mean average of roughly 170,000 barrels per well and a median of 103,000 barrels per well across all the Eagle Ford counties.

The county-level representation derived from well-level data implemented in AEO2014 allows the model to reflect rapid growth in production for plays in the early years of development, when producers focus on developing the most productive wells in the formation's sweet spots [6], the plateau in production as new drilling offsets the decline in production from older wells, and an eventual decline in production as development moves to less-productive areas (Figure IF2-4). However, there is still a great deal of uncertainty underlying the recovery of tight oil in known plays, as well as the potential for production from additional plays or other layers within a currently productive formation that has not been tested. The application of refinements to current technologies, as well as new technology advances, can also have significant (but uncertain) impacts on the recoverability of tight and shale crude oil.

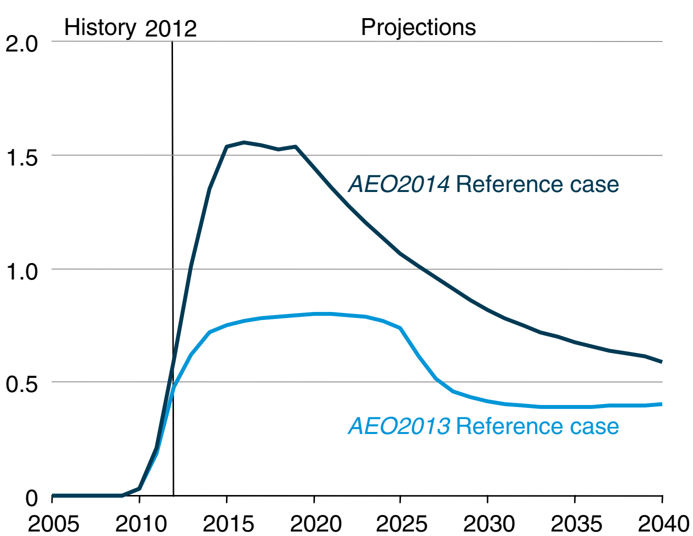
High and Low Resource cases

The High and Low Oil and Gas Resource cases in AEO2014 were developed using assumptions that result in higher and lower estimates of technically recoverable crude oil and natural gas resources than those in the Reference case [7]. These cases allow for an examination of the potential impacts of higher and lower domestic supply on energy demand, imports, and prices, but they do not represent upper and lower bounds for future domestic oil and natural gas supply. The two cases are not symmetric; currently, there is more uncertainty about the potential for greater gains in production than about the potential for lower production levels.

The High Oil and Gas Resource case assumes a broad-based future increase in crude oil and natural gas resources, not limited to production of oil and natural gas in tight sands and shales. However, optimism about increased supply has been buoyed by recent advances in the production of crude oil and natural gas from tight and shale formations. With the adjusted resource and technology advance assumptions in the High Oil and Gas Resource case, domestic crude oil production continues to increase to more than 13 MMbbl/d before 2035. Specific assumptions for the High Oil and Gas Resource case, as compared with the Reference Case, include:

- EURs for tight oil, tight gas, and shale gas wells are 50% higher [8]
- Additional tight oil resources as well as 50% lower well spacing (i.e., wells are closer together), with a downward limit of 40 acres per well for existing and potential future tight oil resources, to capture the possibility that additional layers or new areas of low-permeability zones will be identified and developed
- Diminishing returns on the EUR when drilling in a county exceeds the number of potential wells assumed in the Reference case [9], to capture the probability that greater drilling density will cause wells to interfere with each other (i.e., production from one well might reduce production from a nearby well)
- Long-term technology improvements beyond those assumed in the Reference case, represented as a 1% annual increase in the EURs for tight oil, tight gas, and shale gas wells
- More resources in Alaska and in the lower 48 offshore, including the development of tight oil in Alaska and 50% higher technically recoverable undiscovered resources for other Alaska crude oil and the lower 48 offshore (which reflects more favorable resolution of the uncertainty surrounding undeveloped areas where there has been little or no exploration and development activity, and where modern seismic survey data are lacking)
- The development of lower 48 onshore oil shale (kerogen), with production reaching 135,000 barrels per day by 2025.

Figure IF2-4. Eagle Ford crude oil production in the Reference case, 2005-40 (million barrels per day)



The High Oil and Gas Resource case does not include exploration or production activity in the Arctic National Wildlife Refuge.

The Low Oil and Gas Resource case reflects only the uncertainty around tight and shale crude oil and natural gas resources—specifically, whether the performance of current and future wells drilled will actually be less than estimated. For the Low Oil and Gas Resource case, the EUR per tight and shale well is assumed to be 50% lower than in the AEO2014

Reference case (by scaling all applicable production decline curves). All other resource assumptions are unchanged from the Reference case.

Effects on domestic crude oil production

The difference in overall production across cases mostly reflects differences in tight oil projections. In the High Oil and Gas Resource case, higher well productivity reduces development and production costs per unit, which results in more and earlier development of tight oil resources than in the Reference case. The greater abundance of tight oil resources in the High Oil and Gas Resource case causes tight oil production to peak later in the projections, at 8.5 MMbbl/d in 2035, compared to the Reference case peak production rate of 4.8 MMbbl/d in 2021. From 2012 through 2040, cumulative tight oil production in the High Oil and Gas Resource case amounts to 75 billion barrels, compared with 44 billion barrels in the Reference case.

In the Low Oil and Gas Resource case, lower estimates of tight oil, tight gas, and shale gas resources result in a U.S. production profile that is both slower and lower than in the Reference case, with tight oil production peaking at 4.3 MMbbl/d in 2016 and then declining through 2040. Cumulative tight oil production from 2012 through 2040 amounts to 34 billion barrels in the Low Oil and Gas Resource case, which is 23% less than in the Reference Case.

Effects on U.S. net imports of petroleum and other liquids

The variations in projected domestic petroleum supply between the Reference case and the High and Low Oil and Gas Resource cases result in significant variations in the share of net imports in total U.S. liquid fuels consumption (Figure IF2-2). The net import share of petroleum and other liquids consumption, which increased steadily from 27% in 1985 to about 60% in 2005, has fallen since 2005, to roughly 40% in 2012. In the Reference case, the share of U.S. petroleum and other liquids consumption met by imports continues declining to 25% in 2016, and then begins a gradual increase starting in 2020, reaching 32% in 2040. The net import share follows a similar trend in the Low Oil and Gas Resource case, falling to 27% in 2016 and then rising to 40% in 2040. In contrast, net import dependence continues to decline through 2036, and it is at or near zero from that point until 2040 in the High Oil and Gas Resource case.

Effects on prices

As a result of higher levels of U.S. crude oil production in the High Oil and Gas Resource case, North Sea Brent crude oil prices are lower than in the Reference case: $125 per barrel (2012 dollars) in 2040, compared with $141 per barrel in 2040 in the Reference case. Lower motor gasoline and diesel prices in the transportation sector encourage more consumption.

In the Low Oil and Gas Resource case, lower levels of domestic crude oil production result in a slightly higher Brent crude oil price than in the Reference case—$145 per barrel (2012 dollars) in 2040. As noted above, because the uncertainty around production increases is greater than the uncertainty around production decreases, assumptions in the Low Oil and Gas Resource case are closer to the assumptions in the Reference case than are the assumptions in the High Oil and Gas Resource case.

Endnotes for IF2

Links current as of April 2014

1. 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 shale, sandstone, and carbonate formations, with permeability being a laboratory measure of the ability of a fluid to flow through the rock. In limited areas of some very low permeability formations, small volumes of oil have been produced for many decades.
2. A play is defined as a set of known or postulated oil and gas accumulations sharing similar geologic, geographic, and temporal properties, such as source rock, migration pathway, timing, trapping mechanism, and hydrocarbon type.
3. The hyperbolic decline curve is given by $Q_t = Q_i / [(1 + bD_i t)^{1/b}]$, where Q_t is the production volume in time t (in months), Q_i is the initial volume at time 0 (the 30-day initial production rate or IP is Q_1), D_i is the initial decline rate, and b is the hyperbolic parameter (b of 0.001 is basically an exponential decline). Because the reported production in the first month could include 1 to 31 days of actual production, the first-month data are excluded from the fitting routine.
4. Of the 6,594 Eagle Ford wells included in the Drillinginfo database, 927 were excluded because they had less than four months of production data—leaving 5,667 to be evaluated through the automated fitting routine. For 95% of the wells, monthly production was fitted successfully to a hyperbolic decline curve.
5. Planned future enhancements to this methodology include taking into account any available geologic information (i.e., porosity, depth, thickness, total organic carbon, thermal maturity, and natural fracture density and location) to provide appropriate weights for the adjacent county EURs.
6. Sweet spot is an industry term for those selected and limited areas within a play where the well EURs are significantly higher than those for the rest of the play—sometimes as much as 10 times higher than those for the lower production areas within the play.
7. The total unproved technically recoverable crude oil resources are 401 billion barrels in the High Oil and Gas Resource case and 180 billion barrels in the Low Oil and Gas Resource case, compared to 209 billion barrels in the Reference case. Total unproved technically recoverable dry natural gas resources are 3,349 trillion cubic feet (Tcf) in the High Oil and Gas Resource case and 1,480 Tcf in the Low Oil and Gas Resource case, compared to 1,932 Tcf in the Reference case.
8. This is achieved by scaling the applicable production decline curves upward.
9. For this assumption, the initial production rate is increased by 20%, but the decline curve is shifted so that the overall EUR is reduced by 20%.

Figure and table sources for IF2

Links current as of April 2014

Figure IF2-1. U.S. crude oil production in three cases, 1960-2040: History: U.S. Energy Information Administration. Monthly Energy Review September 2013, DOE/EIA-0035 (2013/09) (Washington, DC, September 2013). **Projections:** AEO2014 National Energy Modeling System, runs REF2014.D102413A, LOWRESOURCE.D112913A, and HIGHRESOURCE.D112913B.

Figure IF2-2. Net import share of U.S. petroleum and other liquids consumption in three cases, 1990-2040: History: U.S. Energy Information Administration. Monthly Energy Review September 2013, DOE/EIA-0035 (2013/09) (Washington, DC, September 2013). **Projections:** AEO2014 National Energy Modeling System, runs REF2014.D102413A, LOWRESOURCE.D112913A, and HIGHRESOURCE.D112913B.

Table IF2-1. Average EUR for wells in the Eagle Ford formation starting production between January 2008 and June 2013 and with at least four months of production: U.S. Energy Information Administration.

Figure IF2-3. Distribution of estimated ultimate recovery per well in seven counties in the Eagle Ford formation, 2013: U.S. Energy Information Administration.

Figure IF2-4. Eagle Ford crude oil production in the Reference case, 2005-40: History: U.S. Energy Information Administration. **Projections:** AEO2014 National Energy Modeling System, run REF2014.D102413A, and AEO2013 National Energy Modeling System, run REF2013.D102312A.

IF3. Potential of liquefied natural gas as a freight locomotive fuel

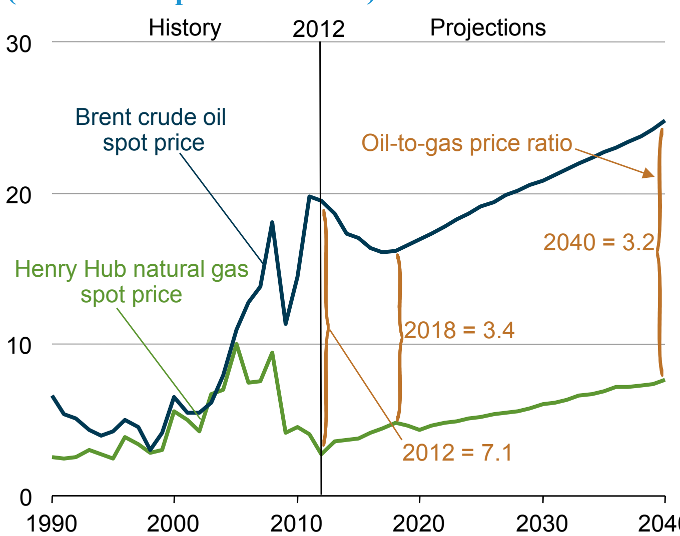
Continued growth in domestic natural gas production, along with substantially lower natural gas spot prices compared to crude oil, is reshaping the U.S. energy economy and attracting considerable interest in the potential for fueling freight locomotives with liquefied natural gas (LNG). While there is significant appeal for major U.S. railroads to use LNG as a fuel for locomotives because of its potentially favorable economics compared with diesel fuel, there are also key uncertainties as to whether, and to what extent, the railroads can take advantage of this relatively cheap and abundant fuel.

Freight railroads and the basic economics of fuel choice

Major U.S. railroads, known commonly as Class 1 railroads, are defined as line-haul freight railroads with certain minimum annual operating revenue. Currently, that classification is based on 2011 operating revenue of $433.2 million or more [*1*]. While there are 561 freight railroads operating in the United States, only seven are defined as Class 1 railroads. The Class 1 railroads account for 94% of total freight rail revenue [*2*]. They haul large amounts of tonnage over long distances, and in the process they consume significant quantities of diesel fuel. In 2012, the seven Class 1 railroads consumed more than 3.6 billion gallons (gal) of diesel fuel [*3*], amounting to 10 million gal/day and representing 7% of all diesel fuel consumed in the United States. The two largest consumers of diesel fuel among the Class 1 railroads—Burlington Northern Santa Fe (BNSF) and Union Pacific—consumed more than 1 billion gal each in 2012. The cost to Class 1 railroads of consuming such large quantities of diesel fuel was more than $11 billion in 2012, representing 23% of their total operating expense (Table IF3-1).

Class 1 railroads are considering the use of LNG to fuel locomotives because of the potential for significant cost savings. Following years of tight price linkage, spot prices for crude oil (North Sea Brent) and natural gas (Henry Hub) diverged around 2005. In 2012, the Brent spot price was about seven times the Henry Hub spot price on an energy equivalent basis. That differential is projected to narrow in the midterm, but a persistent gap is expected to continue, with crude oil prices more than three times higher than natural gas per million British thermal units (MMBtu) throughout the Reference case projection period, going out to 2040 (Figure IF3-1).

Figure IF3-1. Comparison of spot prices for Brent crude oil and Henry Hub natural gas, 1990-2040 (2012 dollars per million Btu)



The large differential between crude oil and natural gas commodity prices translates directly into a significant disparity between projected LNG and diesel fuel prices, even after accounting for natural gas liquefaction costs that exceed refining costs. In the AEO2014 Reference case, the long-run price difference between locomotive diesel fuel and LNG in rail applications increases from $1.48/gal of diesel equivalent in 2014 to $1.77 in 2040 (Figure IF3-2).

Given the difference between LNG and diesel fuel prices in the Reference case, railroads that switch locomotive fuels could accrue significant fuel cost savings. Locomotives are used intensively, consume large amounts of fuel, and are kept in service for relatively long periods of time. The net present value of future fuel savings across the Reference case projection for an LNG locomotive compared to a diesel counterpart is well above the roughly $1 million higher cost of the LNG locomotive and tender (Figure IF3-3).

Relatively large changes in assumptions used to evaluate investments in LNG locomotives (such as a significantly shorter payback period or much higher discount rate) or in

Table IF3-1. Class 1 railroad diesel fuel consumption, fuel cost, and fuel cost share of operating expense, 2012

Class 1 railroad (2012)	Diesel fuel consumption (gallons)	Fuel cost (thousand 2012 dollars)	Fuel cost share of total operating expense
Burlington Northern Santa Fe	1,335,417,552	$4,273,779	29%
Union Pacific	1,108,029,359	$3,505,671	24%
CSX Transportation	490,902,017	$1,542,747	18%
Norfolk Southern	462,466,433	$1,437,178	18%
Canadian National Grand Trunk	101,555,124	$326,303	16%
Canadian Pacific Soo	71,575,774	$231,211	16%
Kansas City Southern	64,078,412	$195,428	22%
Total	**3,634,024,671**	**$11,512,317**	**23%**

fuel prices would be required to change LNG fuel economics for railroad use from favorable to unfavorable. Starting from the Reference case, the economics for switching to LNG locomotives remain favorable unless the payback period is reduced by eight years or the discount rate applied is raised by nine percentage points (Figure IF3-4). However, in the Low Oil Price case, the net present value of fuel cost savings associated with LNG use are not large enough to offset the higher additional upfront cost of LNG locomotives and tenders (Figure IF3-5). The shortfall in the value of fuel savings relative to upfront investment increases over the projection period in this case, making investments in LNG fueling less attractive over time. Clearly, uncertainty about future fuel prices suggests that there is some risk for companies in making such a fundamental change in freight rail operations.

Challenges for liquefied natural gas as a freight rail fuel

While simple economic calculations involving the comparison of fuel cost savings to additional upfront cost are relatively straightforward, other factors, including operational, financial, regulatory, and mechanical challenges, also affect fuel choices by railroads. One of the most challenging factors raised by the switch to LNG locomotives by Class 1 railroads is the effect on operations. Switching from diesel fuel to LNG would require a new delivery infrastructure for locomotive fuel. Natural gas would need to be delivered to fuel depots, either by truck in smaller quantities, as LNG [*4*], or perhaps by pipeline. Larger quantities of

Figure IF3-2. Comparison of prices for railroad diesel fuel and liquefied natural gas fuel, 2014-40 (2012 dollars per gallon diesel equivalent)

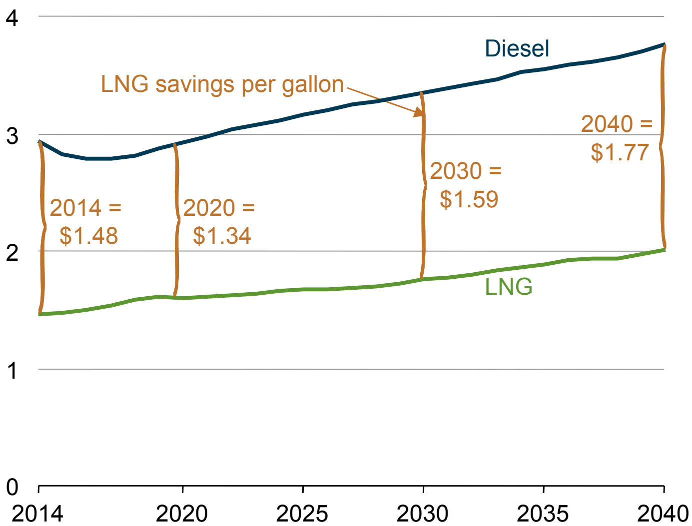


Figure IF3-3. Discounted fuel cost savings for a new locomotive and tender using liquefied natural gas as a fuel compared to diesel, 2020-40 (million 2012 dollars, net present value)

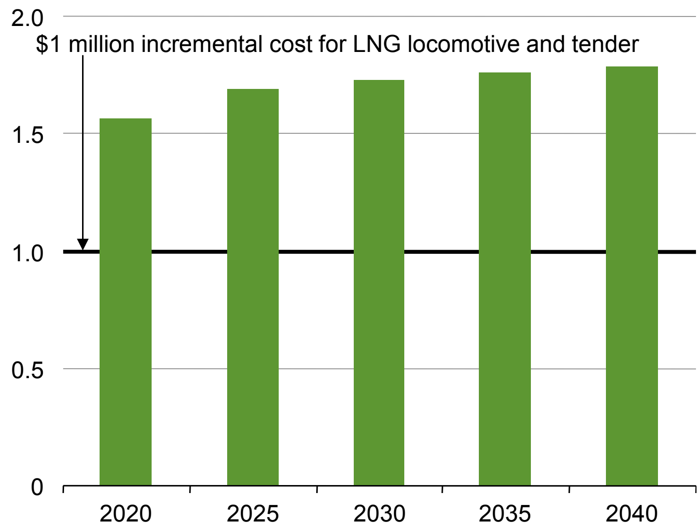


Figure IF3-4. Net present value calculation for locomotives using liquefied natural gas at Reference case fuel prices (payback years and discount rate)

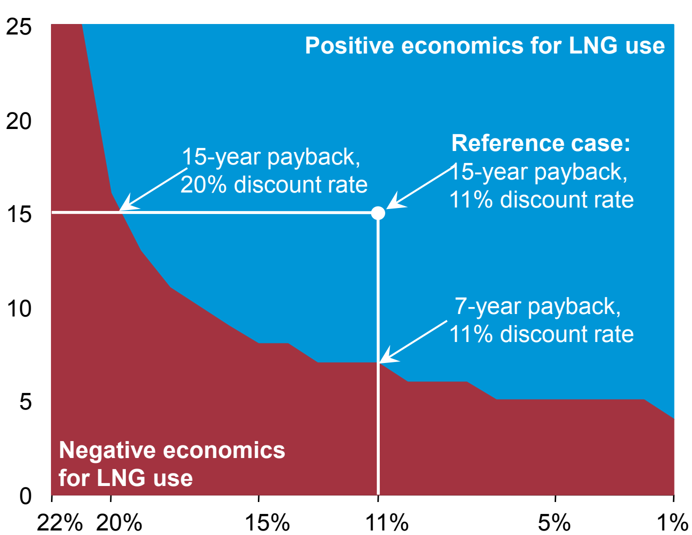
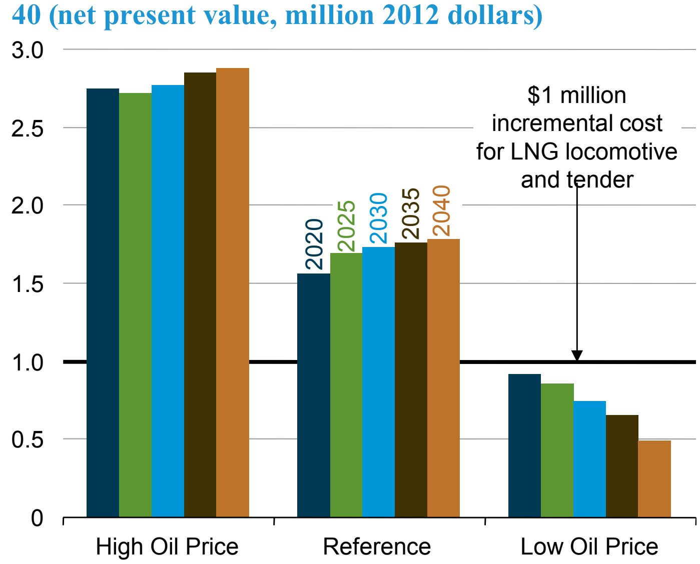


Figure IF3-5. Discounted average fuel cost savings for a new locomotive and tender using liquefied natural gas as a fuel compared to diesel in three cases, 2020-40 (net present value, million 2012 dollars)



natural gas would require liquefaction before delivery to tender cars for use in locomotives. Building the new infrastructure would require a large financial investment in addition to the large investments made in locomotives and tender cars.

The building of LNG refueling infrastructure could also complicate the inter-operability of the rail network, depending on how quickly modifications could be made to accommodate refueling at multiple points around the nation. Impeding the ability of the rail network system to move goods because of a lack of fuel availability could drive up costs and lead to reductions in network flexibility and operational efficiency [*5*]. In addition, operations could be further affected by fuel switching because of the cost of training staff at refueling depots and in maintenance shops, updating maintenance facilities to handle LNG locomotives and tenders, and managing more extensive logistics [*6*]. Further, LNG locomotives and tender cars could require more maintenance than their diesel counterparts. All of these operational changes would create a duplicative infrastructure [*7*], because many diesel-fueled locomotives still would be in service at least for some significant period, and compression-ignited LNG locomotives still require at least some diesel fuel for combustion ignition.

Replacing the current stock of diesel locomotives with LNG locomotives and tender cars would represent a significant financial investment by Class 1 railroads. In 2012, there were 25,174 locomotives in the service of Class 1 railroads, the vast majority of which were line-haul locomotives [*8*]. A new diesel line-haul locomotive costs about $2 million [*9*], and rebuilt locomotives cost about half that amount. With a new LNG locomotive and tender costing about $1 million more than a diesel counterpart, the cost to replace the entire diesel locomotive stock with LNG locomotives and tenders would be tens of billions of dollars, not including additional infrastructure, training, logistics, and a potential increase in maintenance costs. Moreover, much of the cost of the transition, such as purchases of locomotives and tender cars, potentially would occur over a much shorter time period than a fuel payback period.

The financing requirement of large capital expenditures complicates the rather straightforward calculation of locomotive fuel economics. The amount of capital available to Class 1 railroads, either on hand or raised in capital markets, is an important factor in determining whether, or to what extent, railroads can take advantage of fuel cost savings over time. The decision to switch from diesel fuel to LNG is also influenced by the facts that railroads are a highly capital-intensive industry [*10*] with complete responsibility for maintaining the physical rail network, that they face many competing needs for financial investment, and that they must ensure adequate return on investment for their shareholders.

On the regulatory side, LNG rail cargos currently are not permitted without a waiver from the Federal Railroad Administration (FRA) under Federal Emergency Management Agency (FEMA) rules. The development of standard LNG tenders and regulations is underway, with issues related to safety, crashworthiness, and environmental impact, including methane leakage, under consideration [*11*].

Finally, LNG locomotives currently are undergoing extensive testing and demonstration to determine their fuel consumption, emissions, operational performance, and range under real-world conditions. Locomotives and tenders will be evaluated to ensure mechanical performance of such components as connections between tender and locomotive. Several Class 1 railroads are planning to start LNG locomotive demonstration projects to provide better understanding of the obstacles to an LNG fuel switch.

The future of liquefied natural gas in freight rail: lessons from history

The large potential fuel cost savings from the switch to LNG locomotives from diesel has resulted in great interest on the part of the freight rail industry, observers, and analysts. The companies have discussed the potential of LNG as comparable with the switch from steam propulsion to diesel in the 1940s and 50s [*12*], a revolution in freight rail known simply as “dieselization.” Other industry experts have responded with more caution, likening the switch to the more evolutionary transformation of diesel-electric freight rail locomotives from direct current (DC) to alternating current (AC) propulsion that has been occurring since the early 1990s [*13*].

The diesel revolution in rail began in yard-switching operations during the mid-1920s, followed by passenger rail in the mid-1930s. After an initial period of hesitation, mainly because of the vast amount of capital already invested in steam locomotives and their refueling and watering infrastructure, diesel freight locomotives first appeared in 1941. They then captured the market at an extraordinary rate, with the last steam locomotive mustered out of service in 1961 [*14*].

The advantages of using diesel locomotives over steam were numerous. While diesel locomotive costs were about double per horsepower compared to steam, diesel locomotives proved superior in almost every other way. Steam locomotives had to slow or stop to take on water, requiring extensive watering infrastructure, and they needed nearly constant cleaning, maintenance, and repair, with annual costs reaching 25% of the initial cost of the locomotive. The switch to diesel allowed the railroads to avoid costly watering time and infrastructure and dramatically reduced maintenance and repair. As a result, diesel engines could travel faster and thus double the annual mileage of steam locomotives. Diesel engines, unlike steam engines, could be turned on and off with relative ease; a lead diesel locomotive could control other locomotives on a unit train; the costs of rail line maintenance were reduced because diesel locomotives were lighter and did not “pound the tracks”; and maintenance costs were lowered by the use of standardized parts and design [*15*].

Although diesel freight locomotives took over the market in 20 years, freight locomotives with AC traction motors, which began service in Class 1 railroads in the early 1990s, represent about 17% of the locomotive stock today [*16*]. AC locomotives have the major advantage of greater adhesion levels than their counterparts equipped with DC motors, allowing fewer locomotives to pull the same load. The ability to reduce the number of locomotives pulling a unit train represents a significant improvement in fuel efficiency, but it has not been adopted to the same extent as dieselization. Class 1 railroads have gradually adopted or decided against AC traction for a variety of reasons related to operations, upfront incremental costs, and the ability to take advantage of increased adhesion levels. For example, in recent years Union Pacific, Canadian Pacific, and CSX have chosen AC traction locomotives because of locomotive unit reductions, reliability, interoperability, and life-cycle costs. Canadian National Grand Trunk and Norfolk Southern have stayed with DC traction because of incremental cost and the inability to apply unit train reductions. BNSF has chosen AC locomotives for coal runs, where they can take advantage of unit locomotive reductions, and DC locomotives for intermodal runs, where they cannot [*17*].

These historical examples of the impacts of new technologies and fuels may offer insights into the future potential for LNG locomotives. As happened during the diesel revolution, freight railroads may adopt a completely new locomotive fuel and infrastructure over two decades if there is a compelling business case. However, many cost and operational efficiencies made diesel locomotives superior to steam locomotives, and the same dynamic may not be seen with LNG. Moreover, investment in existing capital stock and relevant equipment may be an impediment early in a transformation process.

The ongoing evolution of AC traction locomotives shows that Class 1 railroads will invest in a new locomotive technology, at least gradually, if there is significant reason to do so. The decision may balance factors such as cost with operational efficacy.

Liquefied natural gas in freight rail—revolution and evolution cases

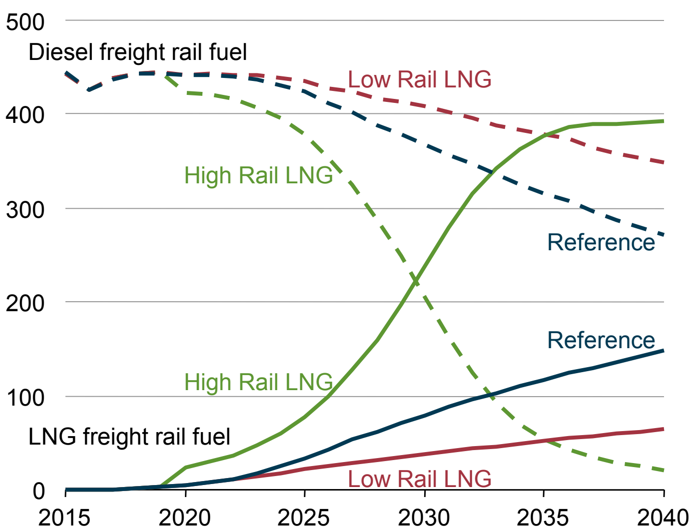
AEO2014 includes two alternative cases that examine the potential impact of LNG in freight rail, based on the diesel revolution and AC traction evolution. The cases also look at the impact of a specific LNG engine technology. The High Rail LNG case represents a revolution in freight rail locomotive fueling similar to that of dieselization in the 1940s and 1950s. After an initial trial period starting in 2017 through 2020, Class 1 railroads take advantage of the favorable economics of LNG locomotive fuel such that after a 20-year period, all freight rail motive stock is converted to LNG capability. The new locomotives are assumed to use high-pressure direct injection (HPDI) LNG engine technology, which uses natural gas as the primary fuel and relies on a small amount of diesel fuel for ignition. HPDI engines use fuel at a ratio of about 95% LNG to 5% diesel. LNG-only engines are not expected to be adopted for locomotives.

The Low Rail LNG case represents an evolution in freight rail locomotive fueling similar to the ongoing penetration of AC traction locomotives. After an initial trial period from 2017 through 2020, Class 1 railroads take advantage of the favorable LNG locomotive fuel economics by turning over their engine stocks at an average rate of 1% per year. The new LNG locomotives are assumed to use a dynamic gas blending engine, which uses diesel fuel for combustion until intake temperature rises, at which point natural gas is used. The engines are LNG-capable up to a fuel consumption ratio of 80% LNG and 20% diesel and have the added advantage of being dual-fuel compatible, with the ability to switch back to 100% diesel fuel as needed. The Reference case does not make any assumption about the type of LNG engine used but instead allows LNG to penetrate into freight rail at the average annual turnover rate of new and rebuilt stock experienced over the last decade.

The High and Low Rail LNG cases show a dramatic change in the fuel mix used by freight rail. In the Reference case, LNG fuel use increases from 0.5 trillion Btu in 2017 to 148 trillion Btu in 2040, or 35% of total freight rail energy consumption (Figure IF3-6). In the High Rail LNG case, LNG fuel consumption increases to 392 trillion Btu in 2040, or 95% of freight rail energy consumption. LNG consumption in the Low Rail LNG case increases to just 64 trillion Btu, or 16% of total freight energy consumption.

While the impacts are dramatic in the freight rail sector, it is important to note that the impacts on total energy use in the U.S. transportation system and on the nation's total energy consumption are relatively small. In the Reference case, transportation diesel consumption increases from about 6 quadrillion Btu in 2012 to 6.5 quadrillion Btu in 2017 and 7.5 quadrillion Btu in 2040, with railroad diesel use of 0.5 quadrillion Btu in 2012 decreasing to 0.4 quadrillion Btu in 2017 and 0.3 quadrillion Btu in 2040, when LNG accounts for 35% of projected energy use by freight rail in the Reference case. Most transportation diesel fuel consumption—more than 80%—occurs in heavy-duty vehicles. Because freight rail accounts for only a small share of transportation diesel use, projected total transportation diesel fuel use in 2040 varies only modestly across cases with different levels of LNG use in freight rail, ranging from 7.3 quadrillion Btu in the High Rail LNG case to 7.6 quadrillion Btu in the Low Rail LNG case.

Figure IF3-6. Comparison of energy consumption for freight rail using diesel and LNG in three cases, 2015-40 (trillion Btu)



Projected natural gas consumption for transportation (excluding pipeline transportation) is sensitive to variation in freight rail use of LNG, because relatively small amounts of natural gas currently are consumed in mobile applications either as compressed or liquefied natural gas. Natural gas consumption in the transportation sector (including pipeline transportation) increases from 0.9 quadrillion Btu in 2040 in the Reference case to 1.1 quadrillion Btu in the High Rail LNG case and to 0.8 quadrillion Btu in the Low Rail LNG case. The projected changes in use of LNG in rail have marginal impacts on retail natural gas prices in the transportation sector, which impact natural gas demand in other transportation uses. As a result of these price changes, heavy-duty truck natural gas demand partially offsets the consumption impacts occurring in rail.

Because the transportation sector is a relatively small consumer of natural gas compared to other sectors, the seemingly dramatic fuel switch from the perspective of freight rail is only a minor change in overall U.S. natural gas consumption. Total U.S. natural gas energy consumption varies from 32.3 quadrillion Btu in 2040 in the Reference case to 32.4 quadrillion Btu in the High Rail LNG case and 32.1 quadrillion Btu in the Low Rail LNG case.

Endnotes for IF3

Links current as of April 2014

1. Association of American Railroads, *Class I Railroad Statistics* (July 9, 2013), https://www.aar.org/StatisticsAndPublications/Documents/AAR-Stats-2013-07-09.pdf. Accessed January 23, 2014.
2. S.C. Davis, S.W. Diegel, and R.G. Boundy, *Transportation Energy Databook: Edition 32,* ORNL-6989 (Oak Ridge, TN, July 2013), Chapter 9, Table 9.8, "Summary Statistics for Class 1 Freight Railroads, 1970-2011."
3. U.S. Department of Transportation, Surface Transportation Board, *Annual Reports Financial Data,* http://www.stb.dot.gov/econdata.nsf/f039526076cc0f8e8525660b006870c9?OpenView.
4. W.C. Vantuono, "A Closer Look at LNG," *Railway Age* (October 2013).
5. BNSF Railway Company, Union Pacific Railroad Company, Association of American Railroads, and California Environmental Associations, *An Evaluation of Natural Gas-fueled Locomotives* (November 2007).
6. W.C. Vantuono, "A Closer Look at LNG," *Railway Age* (October 2013).
7. BNSF Railway Company, Union Pacific Railroad Company, Association of American Railroads, and California Environmental Associations, *An Evaluation of Natural Gas-fueled Locomotives* (November 2007).
8. U.S. Department of Transportation, Surface Transportation Board, *Annual Report Financial Data* (2012 and various years), http://www.stb.dot.gov/econdata.nsf/f039526076cc0f8e8525660b006870c9?OpenView.
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12. K. Smith, "LNG: fuel of the future?" *International Railway Journal* (December 9, 2013), http://www.railjournal.com/index.php/locomotives/lng-fuel-of-the-future.html.
13. W.C. Vantuono, "A Closer Look at LNG," *Railway Age* (October 2013).
14. This summary of many of the major factors related to the switch from steam locomotives to diesel locomotives is taken from C. Wolmar, *The Great Railroad Revolution: The History of Trains in America* (Perseus Books Group, 2012), ISBN 978-1-61039-179-5.
15. C. Wolmar, *The Great Railroad Revolution: The History of Trains in America* (Perseus Books Group, 2012), ISBN 978-1-61039-179-5.
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17. Electro Motive Diesel, "The Merits of AC vs DC Locomotives" (November 2008), http://www.slideshare.net/RailwaysandHarbours/merits-of-ac-vs-dc-locomotives-presentation.

Figure and table sources for IF3

Links current as of April 2014

Table IF3-1. Class 1 Railroad diesel fuel consumption, fuel cost, and fuel cost share of operating expense, 2012: U.S. Department of Transportation, Surface Transportation Board, "Annual Report Financial Data," http://www.stb.dot.gov/econdata.nsf/f039526076cc0f8e8525660b006870c9?OpenView.

Figure IF3-1. Comparison of spot prices for Brent crude oil and Henry Hub natural gas, 1990-2040: History: U.S. Energy Information Administration, *Monthly Energy Review September 2013,* DOE/EIA-0035 (2013/09) (Washington, DC, September 2013). **Projections:** AEO2014 National Energy Modeling System, run REF2014.D102413A.

Figure IF3-2. Comparison of prices for railroad diesel fuel and liquefied natural gas fuel, 2014-40: AEO2014 National Energy Modeling System, run REF2014.D102413A.

Figure IF3-3. Discounted fuel cost savings for a new locomotive and tender using liquefied natural gas as a fuel compared to diesel, 2020-40: AEO2014 National Energy Modeling System, run REF2014.D102413A.

Figure IF3-4. Net present value calculation for locomotives using liquefied natural gas at Reference case fuel prices: AEO2014 National Energy Modeling System, run REF2014.D102413A.

Figure IF3-5. Discounted fuel cost savings for a new locomotive and tender using liquefied natural gas as a fuel compared to diesel in three cases, 2020-40: Projections: AEO2014 National Energy Modeling System, runs REF2014.D102413A, LOWPRICE.D120613A, and HIGHPRICE.D120613A.

Figure IF3-6. Comparison of energy consumption for freight rail using diesel and LNG in three cases, 2015-40: Projections: AEO2014 National Energy Modeling System, runs REF2014.D102413A, RLNGLOW20.D012914C, and RLNGHIGH20.D012914C.

IF4. Light-duty vehicle energy demand: demographics and travel behavior

In 2012, energy consumption by light-duty vehicles (LDVs) accounted for 61% of all transportation energy consumption in the United States, or 8.4 million barrels of oil equivalent per day, and represented nearly 10% of world petroleum liquids consumption. LDV energy use is driven by both LDV fuel economy and travel behavior, as measured by LDV vehicle miles traveled (VMT). LDV VMT per licensed driver peaked in 2007 at 12,900 miles per year and decreased to 12, 500 miles in 2012.

The shift in VMT highlights the importance of travel behavior and its influence on LDV energy consumption. Before the 2007 peak, travel behavior in the United States tracked closely with economic growth. Since 2007, trends in U.S. LDV travel have not followed the trends in economic indicators such as income and employment as closely (Figure IF4-1). Although economic factors continue to influence travel demand, demographic, technological, social, and environmental factors also have shown the potential to affect LDV travel.

The AEO2014 Low and High VMT cases examine variations in travel demand as compared with the Reference case. In the Reference case, VMT per licensed driver begin to increase after 2018. The compound annual rate of growth in total VMT for LDVs from 2012 to 2040 in the AEO2014 Reference case is 0.9%—below the 1.7% rate from 1995 to 2005 but higher than the 0.7% average annual growth rate from 2005 through 2012. The Low VMT case assumes an environment in which travel choices made by drivers result in lower demand for personal vehicle travel, consistent with recent trends in VMT per licensed driver. In the Low VMT case, total U.S. LDV travel demand in 2040 is 19% lower than in the Reference case with annual increase in total LDV VMT from 2012 through 2040 averaging 0.2%. The High VMT case assumes changes in travel behavior that result in an increase in VMT per licensed driver compared with the Reference case. In the High VMT case, total U.S. LDV travel demand in 2040 is nearly 6% higher than in the Reference case with annual increase in total LDV VMT from 2012 through 2040 averaging 1.1% (Figure IF4-2).

The alternative VMT cases have direct implications for both projected energy use by LDVs and associated carbon dioxide emissions. In the Low VMT case, U.S. LDVs consume 5.3 million barrels of oil equivalent per day in 2040, 18% less than in the Reference case, resulting in total transportation sector CO_2 emissions roughly 9% lower than in the Reference case. In the High VMT case, LDVs consume 6.7 million barrels of oil equivalent per day in 2040, or 5% more than in the Reference case, resulting in total transportation sector CO_2 emissions more than 2% higher than in the Reference case (Figures IF4-3 and IF4-4).

Influential travel demand factors

Fuel use by LDVs is directly related to travel demand, which in turn depends on economic, demographic, technological, social, and environmental factors. In general, the demand for LDV travel is likely to decline when licensing rates fall [*1*], use of telework increases, or fuel prices are relatively high. Fuel use by LDVs is likely to rise when the driving-age population grows, during periods of expanding economic activity, or when fuel prices are relatively low.

Economic factors

Although recent U.S. travel indicators have started to decouple from economic indicators, economic indicators still are a dominant influence on levels of personal travel. There are strong links between economic activity and employment and commuting. Employment rates (Figure IF4-5) largely determine the ability of individuals to travel. When people are not employed and have less income, their daily travel is likely to be much lower than when they are commuting to and from work.

The labor force participation rate, defined as the percentage of the total population ages 16 years and older that is employed or looking for work, has declined since the early 2000s [*2*]. Reasons for the decline include increasing retirements and lack of

Figure IF4-1. Economic indicators of travel, 1975-2012 (index, 1995 = 1.0)

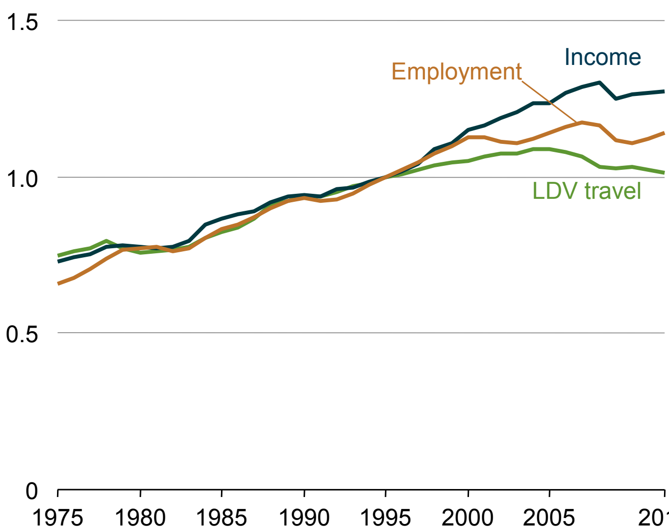
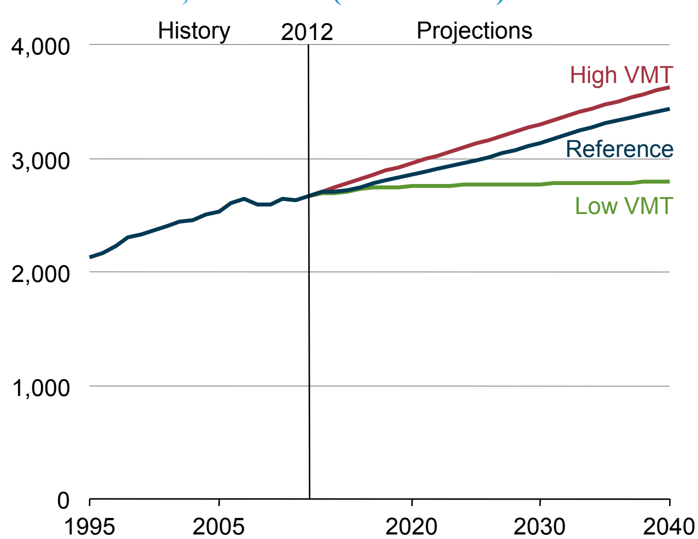


Figure IF4-2. Total light-duty vehicle miles traveled in three cases, 1995-2040 (billion miles)

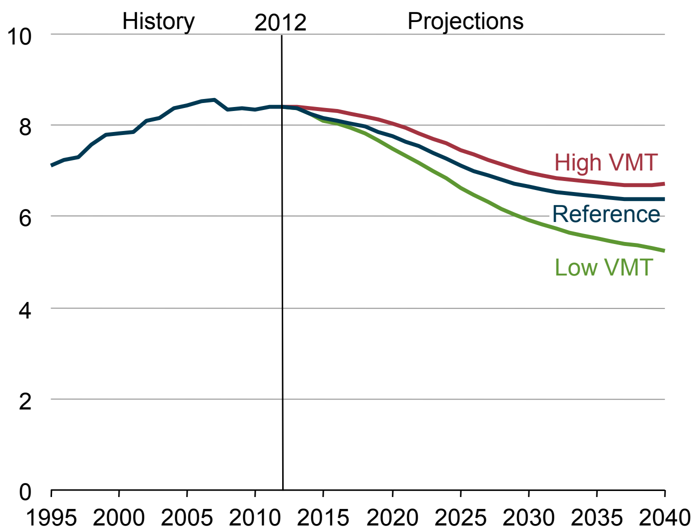


opportunities in the job market (which cause those without jobs to give up on job searches). When the labor force participation rate declines, the unemployment rate may also decline as people are removed from the labor pool, even if overall employment is stable. If the trend continues, retirees and people having difficulty finding jobs may reduce their travel as compared with people who have similar demographic profiles and are employed. When labor force participation rates rise, VMT per driver is likely to increase, particularly for millennials (those born between the early 1980s and early 2000s).

Other macroeconomic factors also influence travel behavior. Income, fuel prices, the costs of purchasing a vehicle, and other vehicle operating costs all influence the extent to which an individual can afford LDV travel. Households with vehicle ownership rates that equal or exceed the number of licensed drivers in the household have maximum non-overlapping access to vehicles. More recently, a business model that provides drivers with access to a shared-pool of vehicles has developed, particularly in urban areas. Because users of shared pool vehicles incur charges for time of use as well as fuel, this model discourages vehicle use for low-value trips. Income provides the financial means to own and operate a vehicle and, therefore, to travel; but operating costs can affect vehicle utilization rates. When fuel prices increase, the cost of driving increases, and many licensed drivers may choose to drive fewer miles, particularly if their personal incomes do not increase at the same rate as fuel prices.

Economic growth and higher employment rates are correlated with increased travel; however, it is unclear to what extent those economic effects may be offset or reinforced by other factors, such as aging of the population, driver licensing rates, telecommuting rates, and access to alternative travel options. The AEO2014 High and Low VMT cases illustrate potential impacts on overall VMT under plausible combinations of factors that could raise or lower VMT.

Figure IF4-3. U.S. light-duty vehicle energy use in three cases, 1995-2040 (million barrels of oil equivalent per day)



Demographic factors

Although economic factors play a significant role, demographic factors such as population, age distribution, and licensing rates also are important determinants of LDV travel demand. Population age groups have different gender distributions, licensing rates, and travel behaviors. As the age groups change over time, long-term effects on VMT will become apparent, particularly for the age groups that have the greatest influence on VMT.

A key factor in the recent shift of personal travel demand is specific travel behavior in age and gender groups. In this analysis, the driving population is divided into five age groups (Table IF4-1), and each age group is further divided into males and females (not shown in the table). Licensing rates differ across age and gender groups. Since 1990, licensing rates generally have been declining for the two youngest age groups and increasing for the two oldest groups (Figure IF4-6). For males, most age groups have seen declining or stagnant

Figure IF4-4. U.S. carbon dioxide emissions in the transportation sector in three cases, 1995-2040 (million metric tons)

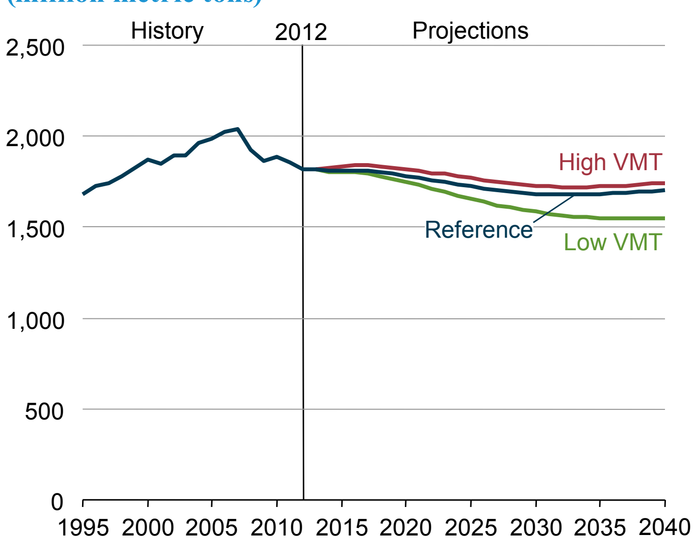
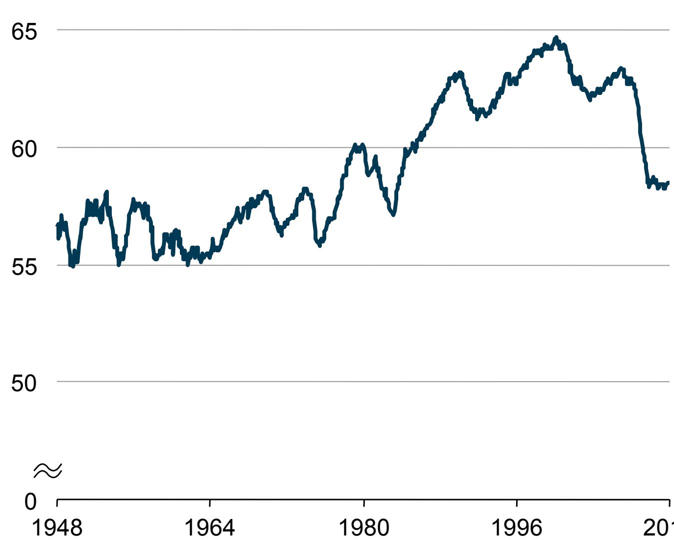


Figure IF4-5. Ratio of U.S. civilian employment to population, 1948-2012 (percent)



licensing rates, with the only exception being males 65 years and older. The female age groups have seen similar stagnation for most of the younger age groups and an increase for females 65 years and older.

Since about 1990, the average age of males who are licensed drivers has been higher than the average age of the male population 16 years and older (the male driving population). That trend is projected to continue as fewer young males obtain licenses or delay obtaining licenses until later in life. Conversely, the average age of female licensed drivers has been lower than the average age of the female driving population, but it is projected to be higher than the average age before 2020 and to continue rising through 2040 (Figure IF4-7). For both males and females, the average age of the driving population and average age of licensed drivers increase in the Reference case, with fewer younger individuals obtaining licenses and more choosing to wait until later in life to become licensed drivers.

The population age 34 years and below has seen a decrease in both licensing rates and VMT per licensed driver, with the licensing rate for the group falling by 5% over the past decade [3]. Some of the decline is a result of increased state restrictions on licenses. For example, for individuals under 18, states almost universally issue provisional licenses with restrictions on driving hours and passengers and do not allow full driving privileges until 18 years of age [4]. Since 2000, VMT per licensed driver for the population under 20 has dropped by 13%. In 1990, 52% of eligible individuals under 20, and 92% of those between 20 and 34 years of age, obtained their licenses. In 2010, those shares were 43% and 86%, respectively [5]. If the trend persists, licensing rates could continue to decline or flatten out for the youngest driving populations, further reducing VMT per capita. If the licensing rate returns to historic levels, total VMT will increase. Technological factors may also play a role for younger age groups, as discussed below.

The peak driving age group, between 35 and 54 years of age, has experienced a small decline in licensing, from 95% in 1990 to an estimated 92% in 2010. Drivers in this age group traveled an average of almost 15,000 miles annually in 2012, the highest rate of VMT per licensed driver for any age group. This relatively large age group, accounting for 34% of the population in 2012, has a limited influence on changes in total VMT, because neither the licensing rate nor the share of the population has changed drastically through history or is projected to change significantly in the future. Much of that stability results from high employment rates for this age group, as a result of the interaction between economic and demographic factors.

The overall population share in the oldest age group, 65 years and older, has grown steadily since 2000 and is expected to reach 24% of the total population ages 16 and above in 2025, up from a 17% share in 2012. Although the size of this segment of the population has grown since 2000, personal travel (VMT per capita) by the oldest age group dropped by 7% between 2008 and 2009, and its total VMT dropped by 10%. More members of the older population are obtaining their licenses than in the past, but they also have altered their travel behavior, increasing their use of public transportation by 40% during the period from 2001 to 2009 [6]. As the aging of the U.S. population continues, long-term effects on VMT will be apparent, particularly as seen in older driver behavior versus younger driver behavior, as well as gender and regional differences in driver behavior.

Table IF4-1. Historic and projected distribution of age groups

	Percent of population ages 16 and above		
Age (years)	2012	2025	2040
16-19	6.9	6.1	6.0
20-34	26.1	24.4	22.8
35-54	34.1	30.9	30.9
55-64	15.5	15.0	13.5
65+	17.4	23.7	26.8

Figure IF4-6. Driver licensing rates by age group, 1990-2010 (percent of total age group)

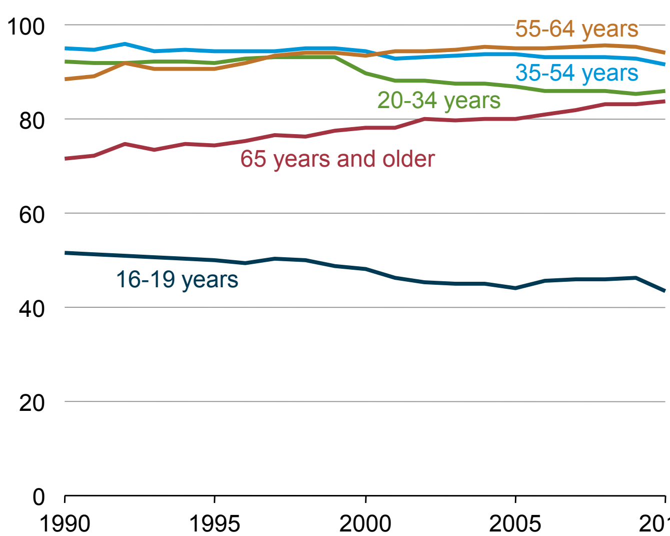
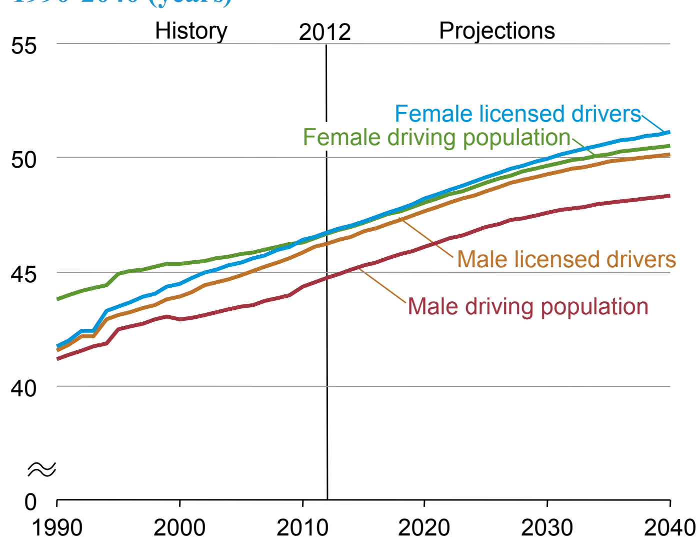


Figure IF4-7. Average ages of male and female driving-age populations and licensed drivers, 1990-2040 (years)



Demographic changes can also interact with other factors to influence VMT. Historically, shifts in demographics coupled with economic changes have had major impacts on total travel. For example, the increasing number of women who entered the work force beginning in the 1970s—and added secondary incomes for their families—led to a rise in VMT that combined both economic activity and demographic changes. In the future, factors that influence VMT may merge in various ways that change long-term trends in U.S. travel demand.

Technological, social, and environmental factors

Technological, social, and environmental factors also can influence VMT. Alternative modes of travel affect VMT to the degree that the population has access to substitutes for personal LDVs. The decision to choose a substitute travel option depends on cost in comparison to personal LDVs, convenience, personal preferences, and the availability of mass transit, rail, biking, and pedestrian travel service options. Other opportunities may also affect personal travel, including car-sharing services, car rental and taxi services, and carpooling.

Technological changes and improvements can also affect VMT. The increasing fuel efficiency of LDVs can influence personal travel by lowering the marginal cost of driving per mile. As vehicle efficiency improves, individuals can drive the same distance with less fuel and therefore at a lower cost, which may result in an increase in VMT. In recent analyses supporting the promulgation of new final fuel economy and greenhouse gas emissions standards for LDVs in model years 2017 through 2025, the National Highway Traffic Safety Administration (NHTSA) and the U.S. Environmental Protection Agency (EPA) applied a 10% rebound in VMT to reflect the lower fueling costs of more efficient vehicles [7].

Other types of technological and environmental changes also can affect personal travel. Telecommuting, e-commerce, urbanization, and social media can supplant or complement personal vehicle use. Telecommuting, or working from home, can influence personal VMT. From 1997 to 2010, the share of the workforce working at least one day of the week from home increased from 7% to 9.5%. As that trend grows, so does the likelihood that individuals will reduce their total miles driven. The share of the working population that works exclusively from home also has increased, from 4.8% in 1997 to 6.6% in 2010 [8]. Although telecommuting can have an impact on reducing VMT, work-related travel in 2009 was only 25% of total personal travel [9].

Technological advances have increased access to and the availability of electronic devices and other opportunities that can influence VMT—including, but not limited to, social media, GPS applications, and electronic devices. Some analysts have suggested an association between rising interest in social media and a decline in the rates at which driving-age youth obtain driver licenses. Others suggest that access to social media actually increases opportunity and desire for travel. Mobile technology and changing preferences of the younger generations will play a significant part in determining the future of LDV travel.

Finally, spatial development patterns may begin to play a different role in determining VMT than is suggested by history, as suburban sprawl gives way to other development patterns. Urbanization generally results in increases in, and greater access to, public transportation and would be likely to support other forms of transportation, including biking, car sharing, and carpooling. Land use changes and related policies, mainly at the local level but supported or incentivized by state and federal policies, have had only localized impacts on VMT to date. However, the tradeoff between suburban and exurban development and urban infill development is likely to change over the coming decades, and those changes could affect VMT.

Figure IF4-8. Vehicle use by drivers 16-19 years old in three cases, 1990-2040 (VMT per licensed driver per year)

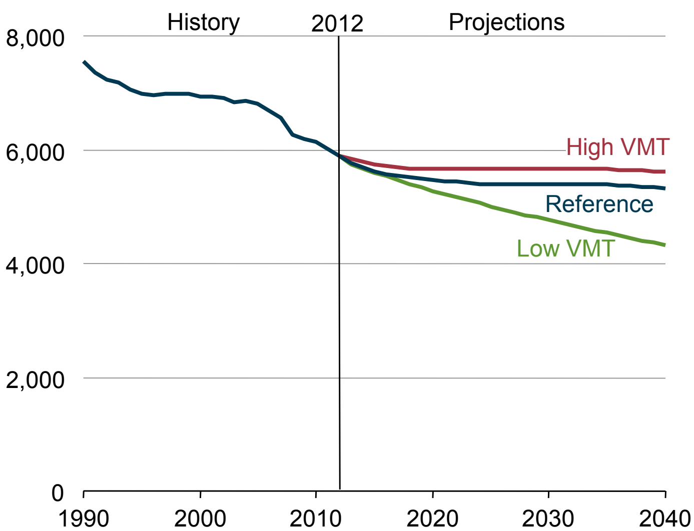
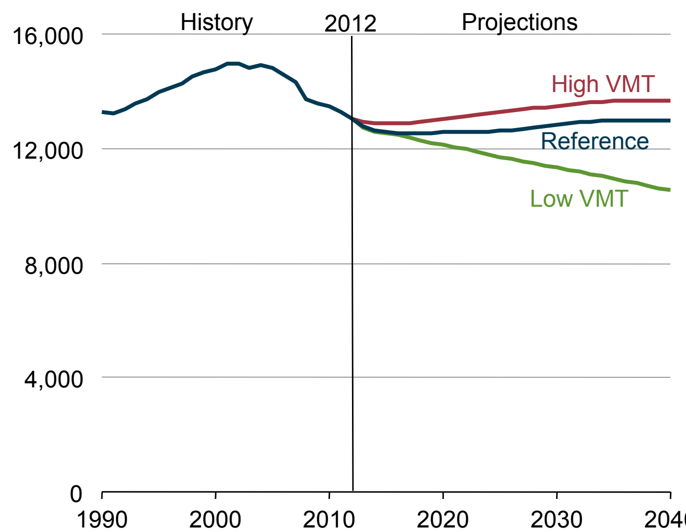


Figure IF4-9. Vehicle use by drivers 20-34 years old in three cases, 1990-2040 (VMT per licensed driver per year)



VMT sensitivity analysis

The High and Low VMT cases suggest possible future changes in travel behavior and their potential impacts on VMT and on LDV energy demand. The Low VMT case assumes a 0.5% annual decrease in VMT per licensed driver from 2013 to 2040 for each age and gender group. The High VMT case assumes a pattern of annual increases in VMT per licensed driver: 0.3% starting in 2013, 0.4% starting in 2016, 0.5% starting in 2019, and 0.6% starting in 2023, slowing to 0.5% starting in 2027, 0.4% starting in 2032, and 0.3% from 2036 through 2040. Figures IF4-8 through IF4-12 show VMT per licensed driver in each case for five age groups.

In the Low VMT case, VMT per licensed driver for all drivers decline throughout the projection, to about 10,400 miles per year in 2040—a 19% decrease from 12,800 miles per year in 2040 in the Reference case. In the High VMT case, VMT per licensed driver for all drivers rise to 13,500 miles per year in 2040—nearly 6% higher than in the Reference case (Figure IF4-13). In the Low VMT case, VMT per licensed driver across all age groups decline by an average of 0.7% per year from 2012 to 2040, compared with an average increase of 0.1% per year in the Reference case. The High VMT case projects 0.3% average annual growth in VMT per licensed driver from 2012 through 2040.

Total LDV VMT increase only slightly in the Low VMT case, to almost 2.8 trillion miles in 2040, as compared with 3.6 trillion miles in 2040 in the High VMT case. Annual increases in total LDV VMT from 2012 to 2040 average 0.2% in the Low VMT case and 1.1% in the High VMT case.

Figure IF4-10. Vehicle use by drivers 35-54 years old in three cases, 1990-2040 (VMT per licensed driver per year)

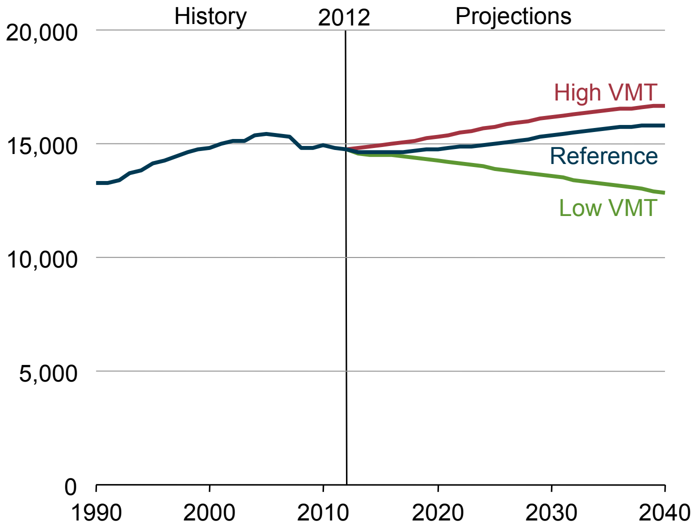


Figure IF4-11. Vehicle use by drivers 55-64 years old in three cases, 1990-2040 (VMT per licensed driver per year)

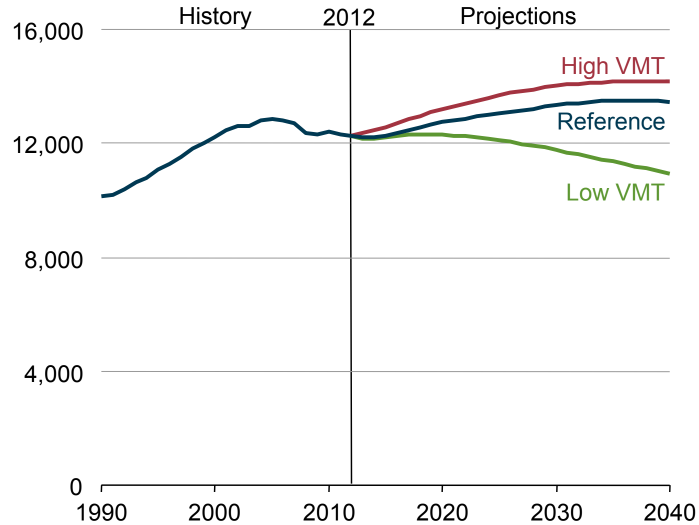


Figure IF4-12. Vehicle use by drivers 65+ years old in three cases, 1990-2040 (VMT per licensed driver per year)

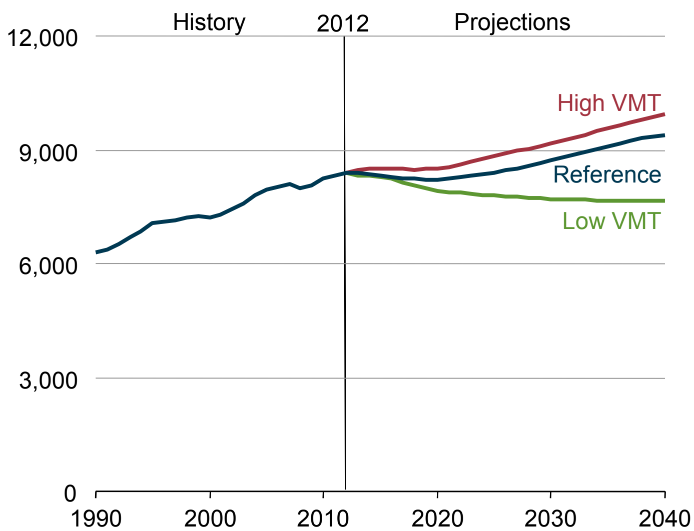
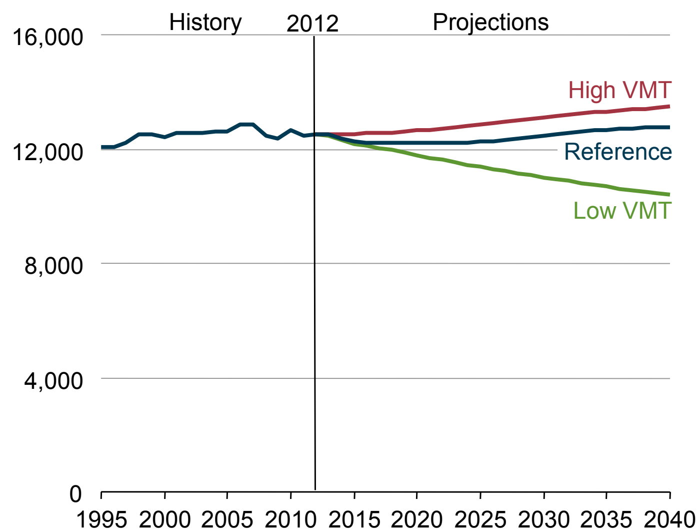


Figure IF4-13. Vehicle use by all drivers in three cases, 1995-2040 (VMT per licensed driver per year)



Endnotes for IF4

Links current as of April 2014

1. The licensing rate is the share of a population or group 16 years old or older that have driver's licenses.
2. U.S. Department of Labor, Bureau of Labor Statistics, "Labor Force Participation Rate," http://data.bls.gov/timeseries/LNS11300000.
3. United States Public Interest Research Group (PIRG) Education Fund and Frontier Group, *Transportation and the New Generation* (April 2012), http://www.uspirg.org/reports/usp/transportation-and-new-generation.
4. Government Highway Safety Association, "Graduated Driver Licensing Laws" (March 2014), http://www.ghsa.org/html/stateinfo/laws/license_laws.html.
5. U.S. Department of Transportation, Federal Highway Administration, Highway Statistics Series (2012), https://www.fhwa.dot.gov/policyinformation/statistics.cfm.
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8. P.J. Mateyka, M.A. Rapino, and L.C. Landivar, *Home-Based Workers in the United States: 2010* (U.S. Department of Commerce, U.S. Census Bureau, Washington, DC, October 2012), https://www.census.gov/prod/2012pubs/p70-132.pdf.
9. U.S. Department of Transportation, Federal Highway Administration, "2009 NHTS - Version 2.1" (February 2011), http://nhts.ornl.gov/download.shtml.

Figure and table sources for IF4

Links current as of April 2014

Figure IF4-1. Economic indicators of travel, 1975-2012: Income: U.S. Bureau of Economic Analysis, "GDP and Personal Income" *National Data,* http://www.bea.gov/iTable/index_nipa.cfm. **Employment:** U.S. Department of Labor, Bureau of Labor Statistics, *Current Employment Statistics,* http://www.bls.gov/ces/#data. **LDV Travel:** U.S. Department of Transportation, Federal Highway Administration, "Table VM-1," Highway Statistics Series 2011 (March 2013), https://www.fhwa.dot.gov/policyinformation/statistics/2011/.

Figure IF4-2. Total light-duty vehicle miles traveled in three cases, 1995-2040: History: U.S. Department of Transportation, Federal Highway Administration, "Table VM-1," *Highway Statistics Series 2011* (March 2013), https://www.fhwa.dot.gov/policyinformation/statistics/2011/. **Projections:** AEO2014 National Energy Modeling System, runs REF2014.D102413A, LOWVMT.D020314B, and HIGHVMT.D020314D.

Figure IF4-3. U.S. light-duty vehicle energy use in three cases, 1995-2040: History: U.S. Department of Transportation, Federal Highway Administration, *National Household Travel Survey,* http://nhts.ornl.gov/download.shtml. **Projections:** AEO2014 National Energy Modeling System, runs REF2014.D102413A, LOWVMT.D020314B, and HIGHVMT.D020314D.

Figure IF4-4. U.S. carbon dioxide emissions in the transportation sector in three cases, 1995-2040: History: S.C. Davis, S.W. Diegel, and R.G. Boundy, *Transportation Energy Data Book,* Edition 31 (July 2012), http://info.ornl.gov/sites/publications/files/Pub37730.pdf. **Projections:** AEO2014 National Energy Modeling System, runs REF2014.D102413A, LOWVMT.D020314B, and HIGHVMT.D020314D.

Figure IF4-5. Ratio of U.S. civilian employment to population, 1948-2012: U.S. Department of Labor, Bureau of Labor Statistics, Current Employment Statistics, http://www.bls.gov/ces/#data.

Table IF4-1. Historic and projected distribution of age groups: U.S. Department of Commerce, U.S. Census Bureau, 2010 Census Data, https://www.census.gov/2010census/data/.

Figure IF4-6. Driver licensing rates by age group, 1990-2010: U.S. Department of Transportation, Federal Highway Administration, "Table DL-22," *Highway Statistics Series 2011* (March 2013), https://www.fhwa.dot.gov/policyinformation/statistics/2011/.

Figure IF4-7. Average ages of male and female driving-age populations and licensed drivers, 1990-2040: History: U.S. Department of Transportation, Federal Highway Administration, "Table DL-22," *Highway Statistics Series 2011* (March 2013), https://www.fhwa.dot.gov/policyinformation/statistics/2011/; and U.S. Department of Commerce, U.S. Census Bureau, *2010 Census Data,* https://www.census.gov/2010census/data/. **Projections:** AEO2014 National Energy Modeling System, runs REF2014.D102413A, LOWVMT.D020314B, and HIGHVMT.D020314D.

Figure IF4-8. Vehicle use by drivers 16-19 years old in three cases, 1990-2040: History: U.S. Department of Transportation, Federal Highway Administration, *National Household Travel Survey,* http://nhts.ornl.gov/download.shtml. **Projections:** AEO2014 National Energy Modeling System, runs REF2014.D102413A, LOWVMT.D020314B, and HIGHVMT.D020314D.

Figure IF4-9. Vehicle use by drivers 20-34 years old in three cases, 1990-2040: History: U.S. Department of Transportation, Federal Highway Administration, *National Household Travel Survey,* http://nhts.ornl.gov/download.shtml. **Projections:** AEO2014 National Energy Modeling System, runs REF2014.D102413A, LOWVMT.D020314B, and HIGHVMT.D020314D.

Figure IF4-10. Vehicle use by drivers 35-54 years old in three cases, 1990-2040: History: U.S. Department of Transportation, Federal Highway Administration, *National Household Travel Survey,* http://nhts.ornl.gov/download.shtml. **Projections:** AEO2014 National Energy Modeling System, runs REF2014.D102413A, LOWVMT.D020314B, and HIGHVMT.D020314D.

Figure IF4-11. Vehicle use by drivers 55-64 years old in three cases, 1990-2040: History: U.S. Department of Transportation, Federal Highway Administration, *National Household Travel Survey,* http://nhts.ornl.gov/download.shtml. **Projections:** AEO2014 National Energy Modeling System, runs REF2014.D102413A, LOWVMT.D020314B, and HIGHVMT.D020314D.

Figure IF4-12. Vehicle use by drivers 65+ years old in three cases, 1990-2040: History: U.S. Department of Transportation, Federal Highway Administration, *National Household Travel Survey,* http://nhts.ornl.gov/download.shtml. **Projections:** AEO2014 National Energy Modeling System, runs REF2014.D102413A, LOWVMT.D020314B, and HIGHVMT.D020314D.

Figure IF4-13. Vehicle use by all drivers in three cases, 1995-2040: History: U.S. Department of Transportation, Federal Highway Administration, *National Household Travel Survey,* http://nhts.ornl.gov/download.shtml. **Projections:** AEO2014 National Energy Modeling System, runs REF2014.D102413A, LOWVMT.D020314B, and HIGHVMT.D020314D.

IF5. Effects of lower natural gas prices on projected industrial production

This analysis focuses on variation in industrial output in the Low and High Oil Price cases and Low and High Oil and Gas Resource cases compared to the *Annual Energy Outlook 2014* (AEO2014) Reference case. Energy-intensive industries, including food, paper, bulk chemicals, glass, cement, iron and steel, and aluminum, are the industries that use the largest amount of energy per unit of output and are the most sensitive to natural gas prices. Of these, the most natural gas-intensive industries are food, paper, bulk chemicals, and glass [*1*].

Analysis of the industrial sector as a whole reveals strong links between natural gas prices and industrial production [*2*]. Further analyses reveal important data issues and indicate some basic sensitivity to natural gas prices for the most energy-intensive industries, subject to trade competition, when they are disaggregated [*3*, *4*]. Those studies show evidence of a straightforward production decline when natural gas prices to the bulk chemicals industry increase, but the relationship does not appear to apply to the less natural gas-intensive cement industry. The same studies point to an important role for demand, both foreign and domestic, for all industries, including the energy-intensive industries. The National Energy Modeling System used to produce AEO2014 includes sufficient disaggregation to support analysis of the influence of natural gas prices on industrial output.

Demand categories

Expenditure categories, such as personal consumption, investment, government spending, and trade, measure underlying demand in the U.S. economy. Each category includes more detailed disaggregation, such as durable and nondurable goods. The AEO2014 industrial output projections use 59 different categories of final demand, with the effects of each category on industrial production differing across industries. The most important final demand categories for the industries analyzed here, according to input-output tables from the Commerce Department's Bureau of Economic Analysis (BEA) [*5*], are consumer spending, trade, and investment (see box below). In addition to demand from domestic consumers and trade, interindustry demand also affects the industrial sector.

Impact of Bureau of Economic Analysis revisions on the National Income and Product Accounts

BEA performs comprehensive National Income and Product Accounts (NIPA) revisions approximately every five years. The 2013 release was its 14th comprehensive revision. The previous release was in July 2009. The BEA comprehensive revisions incorporate changes in the methods used to measure the U.S. economy as well as the most up-to-date, most complete, and most accurate source data available. Changes in NIPA definitions, classifications, and presentations as a result of the 2013 comprehensive revision include:

- Capitalization of expenditures on research and development (R&D)
- Capitalization of expenditures on entertainment, literary, and artistic originals
- Addition of intellectual property products to the fixed investment tables, including R&D; entertainment, literary, and artistic originals; and software
- Accrual treatment of defined benefit pension plan transactions, recognizing the costs of unfunded liabilities
- Expanded set of ownership transfer costs for residential fixed assets
- Change of the reference year for price indexes and inflation-adjusted series.

The AEO2014 Reference case and High and Low Economic Growth cases started with the IHS Global Insight U.S. long-term model simulations available in March and June 2013, which do not reflect the latest comprehensive NIPA revisions for two reasons. First, the July 2013 NIPA revisions were issued late in the AEO preparation cycle. The late issuance of the NIPA revisions delayed the September and October releases of the IHS Global Insight U.S. long-term model simulations, normally used in preparation of the U.S. Energy Information Administration's (EIA) *Annual Energy Outlook* (AEO). Second, EIA uses the economic forecast together with interindustry data describing how each industry uses other industries' output, and how each industry satisfies its final demand components [*6*]. BEA released the updated interindustry tables in December 2013, much too late for the AEO. While the comprehensive NIPA revisions affect past and projected estimates of GDP, they are not expected to materially affect projected energy use. The results of the 2013 NIPA comprehensive revisions will be included in EIA's *Annual Energy Outlook 2015*.

Although the 2013 comprehensive NIPA revision did not lead to changes in broad economic trends or in the general patterns of past business cycles, it did increase gross domestic product (GDP) in every year back to 1929. The average annual growth rate of real GDP from 1929 to 2012 was revised upward to 3.3%, as compared with the previous estimate of 3.2%. More recently, the annual growth rate from 2002 to 2012 was revised upward to 1.8%, as compared with the previous estimate of 1.6%. The economic recession of 2007-09 (December 2007 to June 2009) now looks less severe than previously reported—with GDP contracting by 2.9% over that period after the comprehensive revision, compared with 3.2% before the revision. In addition, the current recovery is stronger than first reported—a 2.2% average annual expansion from the second quarter of 2009 through the first quarter of 2013, compared with 2.1% before the revision. The revised data also indicate that the economy shrank at an average annual rate of 1.3% in the first quarter of 2011, compared with 0.1% growth before the revision.

(continued on next page)

Changes in 2012 nominal GDP as a result of the comprehensive revision total $559.8 billion, including $526 billion (94%) attributable to changes in definitions and $33.8 billion (6%) resulting from statistical changes. Research and development capitalization accounts for 75% of definitional changes, or $396.7 billion. Two-thirds of R&D expenditures are made by the private sector and one-third by government. The remaining changes to definitions include capitalization of entertainment, literary, and artistic originals ($74.3 billion, or 14%); an expanded set of ownership transfer costs for residential fixed assets ($42.3 billion, or 8%); and accrual accounting for defined benefit pension programs ($12.6 billion, or 2%).

Figure IF5-1. Bureau of Economic Analysis revisions to gross domestic product by major component, 2002-12 (billion dollars)

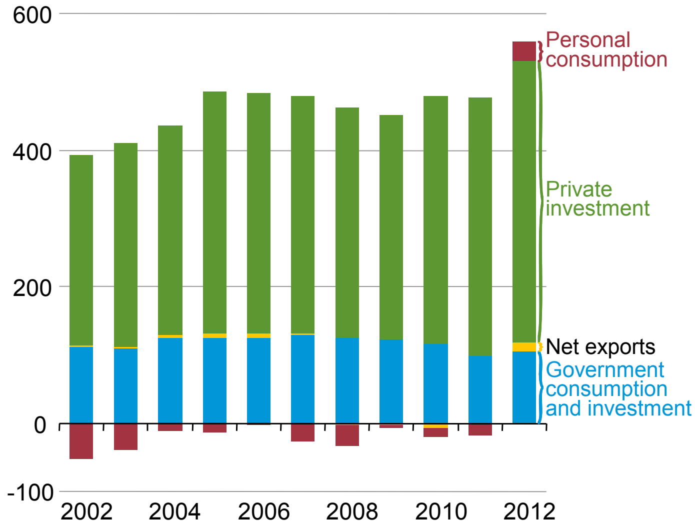


Figure IF5-1 shows the annual impacts of the NIPA revisions on the major components of GDP from 2002 to 2012. Private investment and government expenditures accounted for 92% of the $560 billion upward revision in 2012, primarily as a result of the capitalization of R&D expenditures. Revisions to gross private domestic investment contributed $413 billion, or 74% of the total; revisions to government expenditures contributed $104 billion, or 19% of the total; and revisions to personal consumption and net exports contributed $43 billion, or 7% of the total upward revision to 2012 GDP.

The increase in private and government investment spending is primarily the result of BEA's continued work to broaden the definition of GDP. With this comprehensive revision, NIPA now includes capitalization of spending on R&D and on long-lived artwork produced by artists, studios, and publishers—intangible assets that previously were considered intermediate inputs to the production of other goods or services. Although the inclusion of intangible assets does raise the measured level of overall economic activity, it has only a modest impact on economic growth rates.

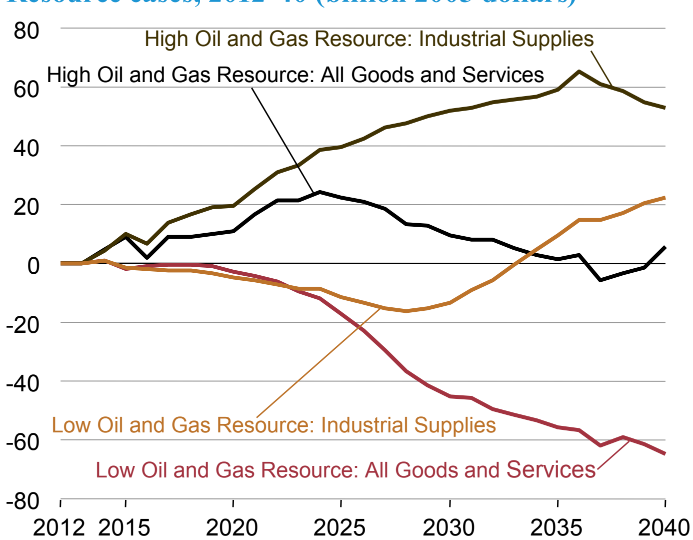
Alternative cases

Results

Oil and Gas Resource cases

Changes in the assumed size of the U.S. oil and natural gas resource base and the rate of technology advance within the sector can affect the nation's economy. In general, increases in oil and natural gas resources result in lower prices and higher industrial output, and a smaller oil and natural gas resource base results in higher prices and lower industrial output. However, the cases are not symmetric. In the High Oil and Gas Resource case, GDP is 1.2% higher in 2040 than projected in the Reference case, total industrial output is 5.1% higher in 2040, and bulk chemicals and paper industries output is 11.5% higher in 2040, as a result of improved trade advantages resulting from lower prices. The changes tend to be smaller in the Low Oil and Gas Resource case. GDP is 0.4% lower in 2040 than projected in the Reference case, total industrial output is 2.3% lower in 2040, and bulk chemicals and paper industries output is 5.0% lower in 2040, as a result of lower oil and natural gas production and higher prices in the Low Oil and Gas Resource case.

Figure IF5-2. Changes from the Reference case in annual net exports, Low and High Oil and Gas Resource cases, 2012-40 (billion 2005 dollars)



Among the final demand categories, trade of industrial supplies (Figure IF5-2) and consumer goods (Figure IF5-3) show the largest differences across the Oil and Gas Resource cases. Energy trade is a major component of industrial supplies. Trade of industrial supplies and consumer goods drives production in the bulk chemicals industry (Figure IF5-4). The price advantage of natural gas-based feedstock varies widely in the High Oil and Gas Resource case (Figure IF5-5), with corresponding impacts on the bulk chemicals industry. Differences in production of bulk chemicals account for a large portion of the differences in fuel consumption results, particularly for petroleum and other liquids and for natural gas, both of which are used as feedstocks in the bulk chemicals industry.

In the High Oil and Gas Resource case, exports of all goods and services from 2012 to 2025 grow faster than imports, as a result of lower U.S. producer prices [7] that are attributable in part to lower natural gas prices (see Figure IF5-2). After 2025, the growth rate of imports begins to increase. Net exports of industrial supplies continue to grow throughout the projection in the High Oil and Gas Resource case, because energy imports are low. In the Low Oil and Gas Resource case, net exports of all goods and services decline through 2040, primarily as a result of slow export growth when U.S. producer prices are higher than those in the Reference case. Net exports of industrial supplies in the Low Oil and Gas Resource case are lower than in the Reference case until 2034, when nonenergy imports drop below Reference case levels as U.S. producer price inflation slows.

Oil Price cases

In comparison with the Reference case, the Low Oil Price case shows lower natural gas prices and production, and the High Oil price case shows higher natural gas prices and production. However, the magnitude of the changes in the Oil Price cases is smaller than in the Oil and Gas Resource cases. The changes in natural gas prices in the Low Oil Price case affect the economy earlier in the projection, leading to changes in inflation, unemployment, and interest rates. In the High Oil Price case, the economy shows larger losses beginning earlier than in the Low Oil and Gas Resource case but recovers as natural gas production expands.

In both the Low and High Oil Price cases, the largest changes from the Reference case are for trade in industrial supplies (Figure IF5-6) and consumer goods (Figure IF5-7), which primarily affect the bulk chemicals, glass, and paper industries. Differences

Figure IF5-3. Changes from the Reference case in consumer spending, Low and High Oil and Gas Resource cases, 2012-40 (billion 2005 dollars)

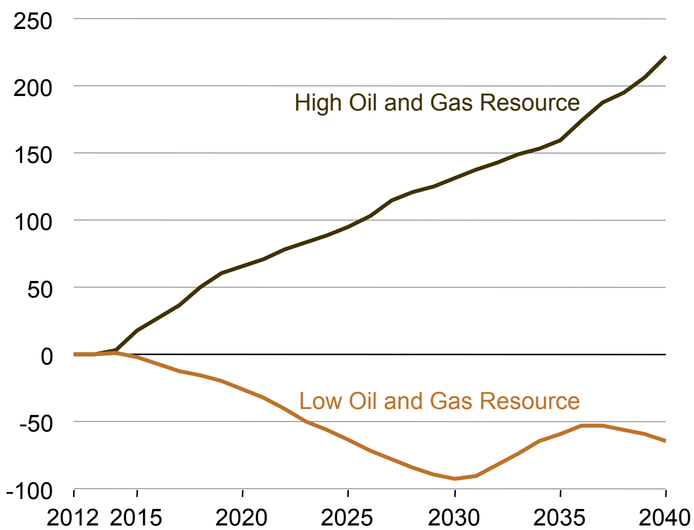


Figure IF5-4. Bulk chemicals value of shipments in three cases, 2012-40 (billion 2005 dollars)

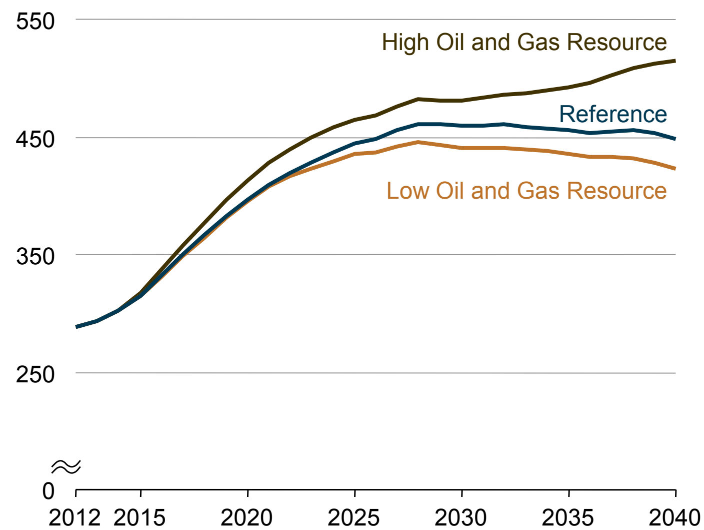


Figure IF5-5. Ratio of ethane to naphtha feedstock prices in three cases, 2012-40

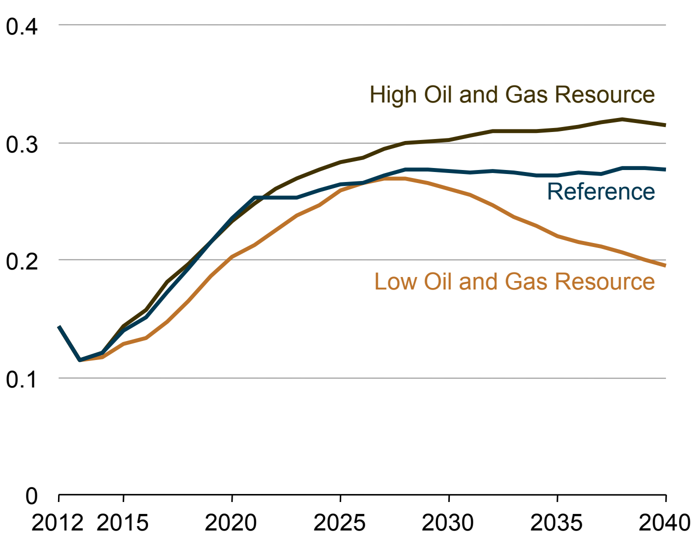


Figure IF5-6. Changes from the Reference case in net exports, Low and High Oil Price cases, 2012-40 (billion 2005 dollars)

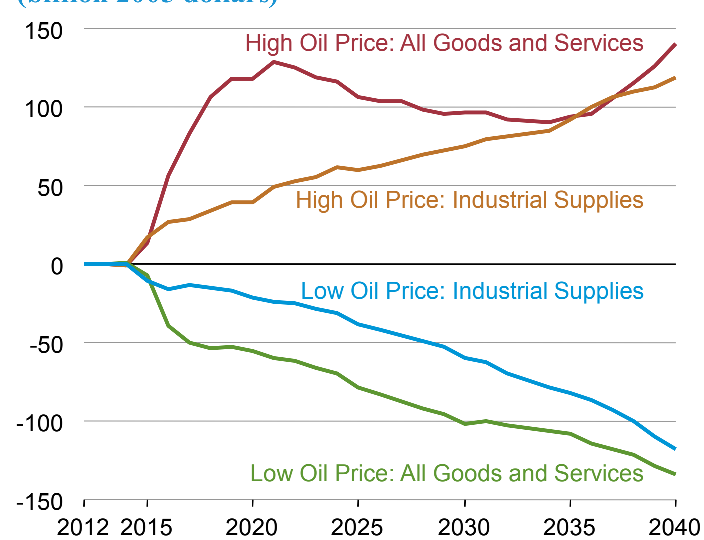
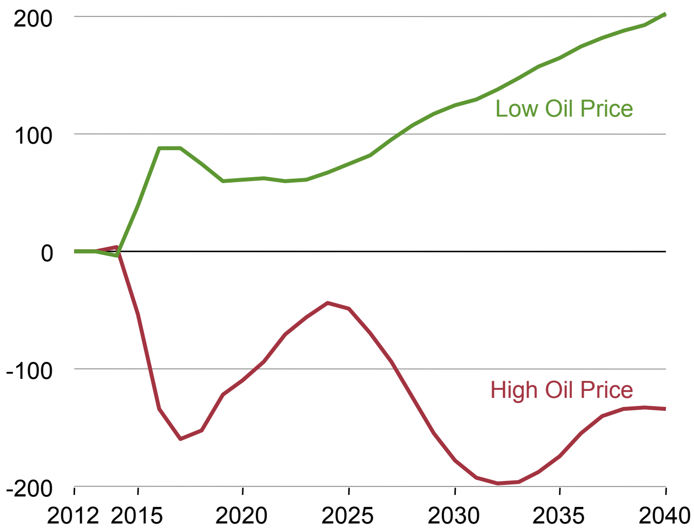


Figure IF5-7. Changes from the Reference case in consumer spending, Low and High Oil Price cases, 2012-40 (billion 2005 dollars)



in consumer spending affect output in the glass and paper industries, which are tightly linked to consumer goods and more closely tied to demand for capital goods than is the bulk chemicals industry. Fuel consumption trends in the Low and High Oil Price cases differ from those in the Low and High Oil and Gas Resource cases, primarily because of the bulk chemicals industry. The initial response of the bulk chemicals industry to higher oil prices compared with the Reference case is a decrease in output (Figure IF5-8), and the initial response to lower oil prices is an increase in output, which does not occur in the High and Low Oil and Gas Resource cases (see Figure IF5-4). In the High Oil Price case, oil prices grow faster than the prices of natural gas-based feedstocks, leading to a price advantage for natural gas feedstocks (Figure IF5-9). As a result, bulk chemicals output in the High Oil Price case in 2040 is higher than in the Reference case. In the Low Oil Price case, with natural gas prices increasing more than oil prices, bulk chemicals output remains below the Reference case level in 2040.

Figure IF5-8. Shipments of bulk chemicals in three cases, 2012-40 (billion 2005 dollars)

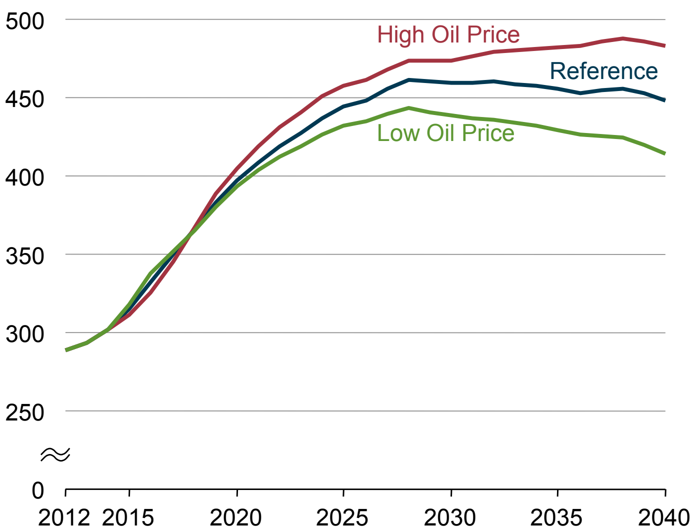
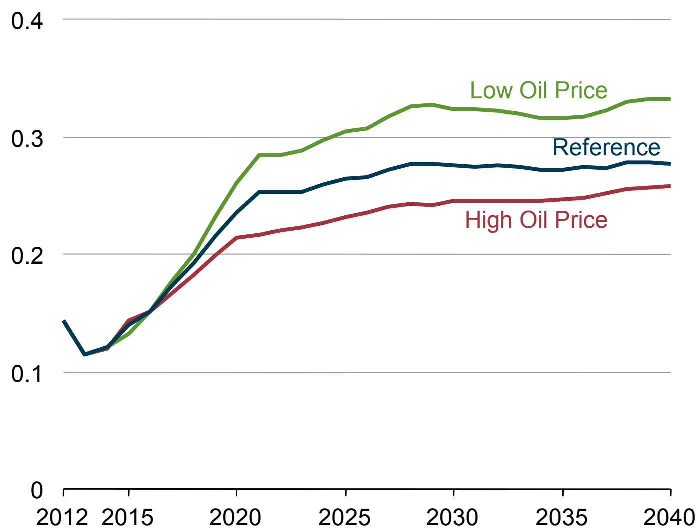


Figure IF5-9. Ratio of ethane to naphtha feedstock prices in three cases, 2012-40



Endnotes for IF5

Links current as of April 2014

1. U.S. Energy Information Administration, 2010 Manufacturing Energy Consumption Survey (MECS), http://www.eia.gov/consumption/manufacturing/index.cfm.
2. V. Arora and J. Lieskovsky, "Natural gas and U.S. economic activity," *The Energy Journal* (forthcoming, 2014).
3. E. Sendich, "The importance of natural gas in the industrial sector with a focus on energy-intensive industries," EIA Discussion Paper (February 28, 2014), http://www.eia.gov/discussionpapers/?src=bookshelf.
4. V. Arora and E. Sendich, "Natural gas and U.S. industrial production: a closer look at four industries" (unpublished).
5. Bureau of Economic Analysis, Industry Accounts, http://bea.gov/industry/index.htm#annual.
6. For a more detailed description of the interindustry data changes, see "Benchmark input-output account of the U.S. economy, 2007" (December 18, 2013), http://www.bea.gov/newsreleases/industry/io/ionewsrelease.htm.
7. The producer price index, used to capture the selling prices received by domestic producers for their output, represents the price paid by industrial sector purchasers for inputs.

Figure sources for IF5

Links current as of April 2014

Figure IF5-1. Bureau of Economic Analysis revisions to gross domestic product by major component, 2002-12: History: U.S. Department of Commerce, Bureau of Economic Analysis, "National Income and Products Account Table," Table 1.1.5, Gross Domestic Product, First Quarter Third Release (Washington, DC, June 26, 2013), http://www.bea.gov/newsreleases/national/gdp/2013/gdp1q13_3rd.htm; and U.S. Department of Commerce, Bureau of Economic Analysis, "National Income and Products Account Table," Table 1.1.5, Gross Domestic Product, Second Quarter Advanced Release (Washington, DC, July 31, 2013), http://www.bea.gov/newsreleases/national/gdp/2013/gdp2q13_adv.htm.

Figure IF5-2. Changes from the Reference case in annual net exports, Low and High Oil and Gas Resource cases, 2012-40: Projections: AEO2014 National Energy Modeling System, runs REF2014.D102413A, LOWRESOURCE.D112913A, and HIGHRESOURCE.D112913B.

Figure IF5-3. Changes from the Reference case in consumer spending, Low and High Oil and Gas Resource cases, 2012-40: Projections: AEO2014 National Energy Modeling System, runs REF2014.D102413A, LOWRESOURCE.D112913A, and HIGHRESOURCE.D112913B.

Figure IF5-4. Shipments of bulk chemicals in three cases, 2012-40: Projections: AEO2014 National Energy Modeling System, runs REF2014.D102413A, LOWRESOURCE.D112913A, and HIGHRESOURCE.D112913B.

Figure IF5-5. Ratio of ethane to naphtha feedstock prices in three cases, 2012-40: Projections: AEO2014 National Energy Modeling System, runs REF2014.D102413A, LOWRESOURCE.D112913A, and HIGHRESOURCE.D112913B.

Figure IF5-6. Changes from the Reference case in net exports, Low and High Oil Price cases, 2012-40: Projections: AEO2014 National Energy Modeling System, runs REF2014.D102413A, LOWRESOURCE.D112913A, and HIGHRESOURCE.D112913B.

Figure IF5-7. Changes from the Reference case in consumer spending, Low and High Oil Price cases, 2012-40: Projections: AEO2014 National Energy Modeling System, runs REF2014.D102413A, LOWRESOURCE.D112913A, and HIGHRESOURCE.D112913B.

Figure IF5-8. Shipments of bulk chemicals in three cases, 2012-40: Projections: AEO2014 National Energy Modeling System, runs REF2014.D102413A, LOWRESOURCE.D112913A, and HIGHRESOURCE.D112913B.

Figure IF5-9. Ratio of ethane to naphtha feedstock prices in three cases, 2012-40: Projections: AEO2014 National Energy Modeling System, runs REF2014.D102413A, LOWRESOURCE.D112913A, and HIGHRESOURCE.D112913B.

IF6. Implications of accelerated power plant retirements

In 2012, coal-fired and nuclear power plants together provided 56% of the electricity generated in the United States. The role of these technologies in the U.S. generation mix has been changing since 2009, as both low natural gas prices and slower growth of electricity demand have altered their competitiveness relative to other fuels. Many coal-fired plants also must comply with requirements of the Mercury and Air Toxics Standards (MATS) and other environmental regulations. Some of the challenges faced by coal-fired and nuclear generators, and the implications for electricity markets if the plants are retired in significant numbers, are analyzed in this discussion.

Of the total installed 310 gigawatts (GW) of coal-fired generating capacity available at the end of 2012, 50 GW, or 16%, is projected to be retired by 2020 in the AEO2014 Reference case. Despite those projected retirements, coal continues to account for the largest share of the electricity generation mix through 2034, after which it is overtaken by natural gas. However, throughout the projection the coal share of total generation remains significantly below its 49% share in 2007, when coal set its annual generation record.

In 2012 and 2013, operators of five nuclear power reactors representing 4.2 GW of capacity announced plans to retire the reactors by 2015. Four of the reactors—San Onofre 2 and 3, Kewaunee, and Crystal River—already have ended nuclear power production, and the fifth, Vermont Yankee, is expected to end generation by the end of 2014 [*1*]. In addition, the Oyster Creek plant is expected to conclude operation in 2019 [*2*]. These are the first retirements of U.S. nuclear power plants since Millstone Unit 1 was retired in 1998. Retirements often are the result of unique circumstances, but some owners of nuclear power plants have voiced concerns about the profitability of their units, sparking discussion of possible additional nuclear retirements [*3*]. In order to evaluate the impacts of potential retirements beyond those in the Reference case, AEO2014 includes several alternative cases with economic assumptions that make it less likely that existing coal and nuclear power plants will be used for generation.

Factors that lead to power plant retirements

Power plant owners generally make the decision to retire plants when their expected costs exceed their expected revenues over the future life of the plants [*4*]. Costs incurred by power plants can include large capital projects, such as installation of flue gas desulfurization (FGD) systems or scrubbers on coal plants, increased operating costs, or higher fuel costs. Revenues are received from energy sales or capacity payments in wholesale electricity markets in regions of the country with competitive wholesale markets, or from cost-recovery mechanisms in regions with vertically integrated utilities subject to rate regulations [*5*].

Recent trends in the electric power industry have resulted in both declining revenues and increased operating costs for coal plants. Because natural gas often is the marginal fuel and thus sets prices in Regional Transmission Organization (RTO) markets, and natural gas influences wholesale electricity prices in non-RTO markets, the decline in natural gas prices beginning in 2008 tends to reduce electricity prices and the payments received by all generators for the electricity they produce. Lower natural gas prices also improve the competitiveness of natural gas combined-cycle (NGCC) power plants relative to coal-fired plants. When lower natural gas prices drive the cost of generating electricity from an NGCC plant below that of a nearby coal-fired plant, the coal plant is dispatched, or operated, less often and earns less revenue [*6*].

Slow growth of electricity demand in recent years has resulted in fewer high-cost marginal generators being dispatched. In regions with excess generating capacity, plants with relatively high variable operating costs may not be dispatched frequently enough to produce the revenue needed to cover their costs [*7*], making them candidates for retirement. Although the average price of coal delivered to the electric power sector declined in both 2012 and 2013, it rose by more than 4% per year from 2007 to 2011, and the resulting increase in operational costs for coal-fired power plants reinforced the impacts of lower demand and more competitive natural gas prices.

When faced with declining profitability, plant owners may choose to retire their units rather than make additional investments to keep them operating. In the AEO2014 Reference case, all coal-fired plants are required to have either a scrubber or a dry sorbent injection (DSI) system combined with a fabric filter in order to continue operating in 2016 [*8*] and later years. As of the end of 2012, 64% of the U.S. fleet of coal-fired generators was compliant with this requirement. The remaining plant owners are in the process of deciding whether to retrofit or retire their plants [*9*].

The outlook for nuclear power also has been altered by the changing conditions in U.S. electricity markets. Nuclear power plants have lower fuel costs than either coal- or natural gas-fired plants, translating to lower variable operating costs and ensuring that they are dispatched when available. The spread between the price of electricity and the fuel cost for nuclear plants is often referred to as the quark spread. Nuclear power plant owners in wholesale markets rely on sufficient quark spreads to cover nonfuel operations, maintenance, and any new capital expenses associated with the plants to provide a return on their investment. Lower wholesale electricity prices have reduced quark spreads for all nuclear power plants, especially those with increasing operations and maintenance (O&M) costs or capital addition costs.

The AEO2014 Reference case assumes an additional 6 GW of generic nuclear retirements from 2012 to 2019, beyond the six reactor retirements already announced (a total that includes the Oyster Creek plant), as higher-cost units face continued economic challenges. Those projected retirements are represented by derating of existing capacity for plants in vulnerable regions, not by retiring any specific plants. Higher natural gas prices in the Reference case after 2020 support the continued operation of the U.S. nuclear fleet and limit retirements from 2020 through 2040.

Accelerated retirement cases

AEO2014 includes several cases designed to explore the effects of alternative assumptions that change projected natural gas prices or electricity demand, or assigns a value to carbon dioxide (CO_2) emissions as a proxy for possible future policies to mitigate greenhouse gas emissions. However, those cases have impacts throughout the energy system and the economy, which makes it difficult to measure the independent effects of significant coal and nuclear capacity retirements. In order to isolate the effects of additional retirements on the energy system, several cases were developed by incorporating assumptions that directly accelerate retirements of coal-fired and nuclear power plants.

Accelerated Coal Retirements case

The AEO2014 High Coal Cost case assumes a decrease in coal mine productivity and an increase in coal transportation costs, causing coal prices to rise to a level 68% above those in the Reference case in 2040. In the Reference and High Coal Cost cases, real O&M costs are flat, which is consistent with long-term historical trends. However, as coal plants age, higher O&M costs may also become a concern because replacement parts and upgrades to plant equipment could be required to keep them operating effectively. In the Accelerated Coal Retirements case, the assumptions of the High Coal Cost case are combined with an assumed 3% annual increase in real O&M costs for coal-fired power plants from 2012 through 2040, with the increase intended to represent the high end of potential future O&M costs. The higher fuel prices and O&M costs in the Accelerated Coal Retirements case serve as proxies for any combination of factors that would produce a higher rate of coal plant retirements.

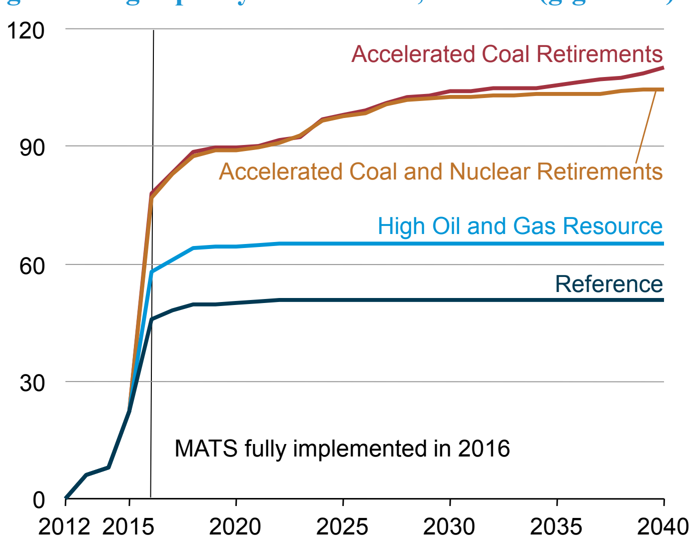
Accelerated Nuclear Retirements case

The Nuclear Regulatory Commission (NRC) has the authority to issue initial operating licenses for commercial nuclear power plants for a period of 40 years and then to extend them in 20-year increments. The NRC has already approved initial 20-year license extensions for more than 70% of the nuclear fleet, and the AEO2014 Reference case assumes that each plant will receive a first license extension unless its planned retirement has specifically been reported. The nuclear power industry currently is developing strategies to submit license applications for additional 20-year life extensions that would allow plants to continue operating beyond 60 years. The AEO2014 Reference case assumes that plants reaching 60 years of age between 2030 and 2040 will be granted a second life extension.

Nuclear power plants operate as baseload capacity. Although they are expensive to build and maintain, they have relatively low variable operating costs, which ensures that they are dispatched when available. While not affecting their dispatch order, increases in nonfuel O&M costs can have negative effects on the economics of nuclear power plants through lower profit margins. To avoid retirement for economic reasons, a plant must maintain a positive net present value over its operating lifetime. As with coal plants, annual O&M costs for nuclear power plants remain flat in the AEO2014 Reference case. However, recent data suggest that O&M costs for nuclear plants rose at an average annual rate of 4% over the 2008-12 period [*10*].

The Accelerated Nuclear Retirements case assumes that O&M costs for nuclear power plants grow by 3% per year through 2040; that all nuclear plants not retired for economic reasons are retired after 60 years of operation; and that no additional nuclear power plants are built after the 5.5 GW of capacity currently under construction is completed. This case reflects uncertainty regarding actions and costs associated with continued operation of the existing nuclear fleet.

Figure IF6-1. Cumulative retirements of coal-fired generating capacity in four cases, 2012-40 (gigawatts)



Accelerated Coal and Nuclear Retirements case

Large-scale simultaneous retirements of both coal-fired and nuclear capacity could have a significant effect on the electric power system. In order to assess that potential effect, the AEO2014 Accelerated Coal and Nuclear Retirements case combines the assumptions of the Accelerated Coal Retirements case and the Accelerated Nuclear Retirements case.

Results

Retirements

In the Accelerated Coal Retirements case, 110 GW of capacity, or 117% more than in the Reference case, is retired by 2040 (Figure IF6-1). In the Accelerated Coal and Nuclear Retirements case, coal retirement levels are similar to those in the Accelerated Coal Retirements case through 2030, with a slight leveling off toward the end of the projection, when some coal-fired capacity is needed to make up for the lost nuclear capacity.

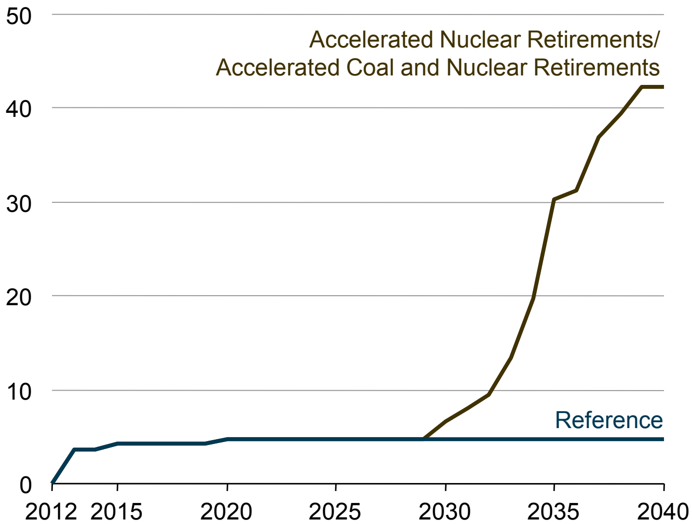
In the Accelerated Nuclear Retirements case, 42 GW of nuclear capacity is retired through 2040 (Figure IF6-2). However, other than retirements early in the projection, there is no significant reduction in nuclear capacity before the plants begin to reach their 60th year of operation, in 2029. The same retirement trajectory is repeated in the Accelerated Coal and Nuclear Retirements case.

There is no incremental increase in nuclear retirements in the Accelerated Nuclear Retirements, despite higher O&M costs. However, incremental retirements do occur in the Low Nuclear case, discussed in the Market Trends section of the AEO2014. The Low Nuclear case uses the same assumptions as the Accelerated Nuclear Retirements case, but also includes the resource assumptions from the High Oil and Gas Resource case that result in lower natural gas prices than in the Reference case. As a result, economic retirements of nuclear power plants that have not operated for 60 years do occur in the last decade of the projection in the Low Nuclear case, with nuclear capacity falling to 35 GW below the levels in the Accelerated Coal and Nuclear Retirements case.

Capacity additions

In order to replace capacity that is retired in the accelerated retirement cases, more total capacity (including capacity in the electric power sector, combined heat and power, and capacity in the end-use sectors) is added than in the Reference case. The new capacity mix consists almost entirely of natural gas and renewable energy sources (Figure IF6-3). Natural gas-fired combined-cycle units are favored because of their low fuel prices and relatively moderate capital costs.

Figure IF6-2. Cumulative retirements of nuclear generating capacity in three cases, 2012-40 (gigawatts)



Generation fuel mix

As existing coal and nuclear plants are retired, natural gas and renewables gain increasing shares of the generation mix (Figure IF6-4). The strength of this trend depends on how much nuclear and coal-fired capacity is retired.

Coal-fired generation in 2040 is lowest in the Accelerated Coal Retirements case, which results in the greatest total loss of coal-fired capacity. In all AEO2014 cases, including the Reference case, available coal-fired capacity operates as baseload generation throughout the projection. Therefore, removing coal capacity results in lower overall levels of generation. Coal-fired electricity generation in 2040 is 1% higher in the Accelerated Nuclear Retirements case than in the Reference case as a result of a small increase in coal-fired capacity installed at the end of the projection period.

Nuclear power plants also consistently operate as baseload generation, and their total generation varies with changes in capacity. In the Accelerated Nuclear Retirements and Accelerated Coal and Nuclear Retirements cases, nuclear

Figure IF6-3. Cumulative additions of electricity generating capacity by fuel in four cases, 2012-40 (gigawatts)

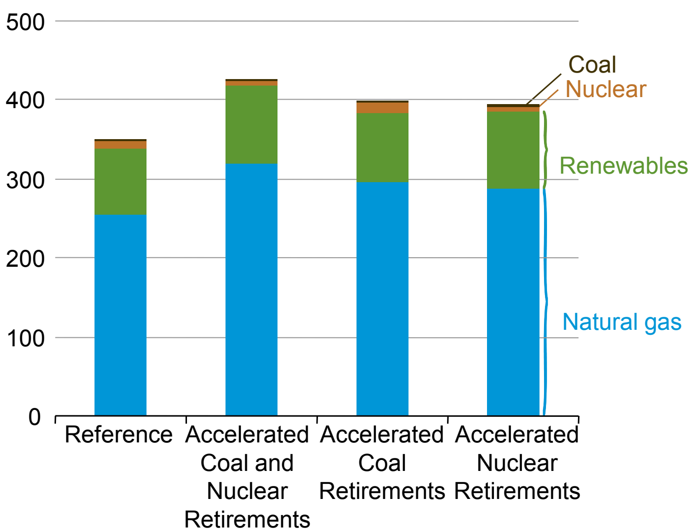
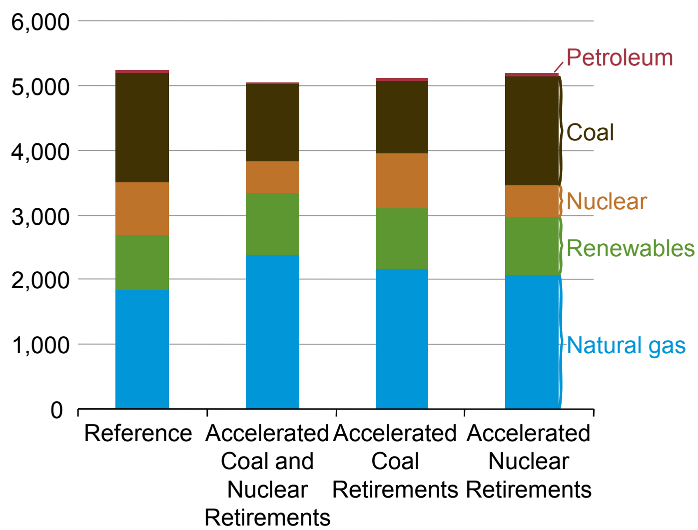


Figure IF6-4. Electricity generation by fuel in four cases, 2040 (billion kilowatthours)



generation in 2040 is 40% lower than in the Reference case. In the Accelerated Coal Retirements case, nuclear electricity generation is 2% above the Reference case level in 2040.

Natural gas prices

In all the AEO2014 accelerated retirement cases, natural gas prices are higher in most years than in the Reference case as retirements of existing coal and nuclear capacity lead to both increased use of existing natural gas-fired plants and the development of new plants. The alternative cases with the largest increases in natural gas-fired generation also have the largest price increases. For example, the price of natural gas delivered to the electric power sector in 2040 in the Accelerated Coal and Nuclear Retirements case is 11% higher than the Reference case price (Figure IF6-5) [*11*].

Carbon dioxide emissions in the electric power sector

Coal and natural gas are the primary sources of CO_2 emissions from the electric power sector. Coal is the most significant contributor, emitting more than twice as much CO_2 per megawatthour (mWh) as a combined-cycle plant fueled by natural gas. Generation using nuclear power and renewables does not emit CO_2.

Because of the high CO_2 intensity of coal, scenarios that result in less coal-fired electricity generation also result in the most significant emissions reductions. Total electric power sector CO_2 emissions in the Accelerated Coal Retirements case are 20% below those in the Reference case in 2040 (Figure IF6-6). Emissions are slightly higher in the Accelerated Coal and Nuclear Retirements case, because some nuclear power generation is replaced by gas-fired generation; however, the effect of the coal-fired capacity retirements still keeps emissions 14% below the Reference case level in 2040. In the Accelerated Nuclear Retirements case, nuclear generation is 328 mWh below the Reference case level in 2040, while electric power sector CO_2 emissions are 85 million metric tons higher, reflecting an average increase of 0.26 metric tons CO_2 per mWh reduction in nuclear generation across the two scenarios. The estimated increase in CO_2 emissions per mWh of nuclear generation reduced, which is slightly below the estimated increase in CO_2 emissions per additional mWh of generation from advanced combined-cycle plants burning natural gas, reflects replacement generation from natural gas and renewables, together with some reduction in overall electricity demand as a result of higher end-user prices.

Retail electricity prices

Retail electricity prices vary in the accelerated retirement cases, because natural gas prices are a key determinant of wholesale electricity prices, which in turn are a significant component of retail electricity prices. Accordingly, the cases with the highest delivered natural gas prices also show the highest retail electricity prices (Figure IF6-7). In 2040, real retail electricity prices in the Accelerated Coal and Nuclear Retirements case are 12% higher than those in the Reference case.

Conclusions

Accelerated retirements of coal-fired and nuclear electricity generation capacity would cause natural gas and renewables to gain an increased share in the nation's electricity generation mix. Natural gas is most often the lowest-cost option for replacement capacity, while renewable generation grows, spurred by the increased economic competitiveness of solar and wind technologies toward the end of the projection period. The rising use of natural gas in the electric power sector results in price increases for both natural gas and electricity in all sectors relative to the Reference case (Table IF6-1).

Figure IF6-5. Delivered price of natural gas to the electric power sector in four cases, 2012, 2025, and 2040 (2012 dollars per thousand cubic feet)

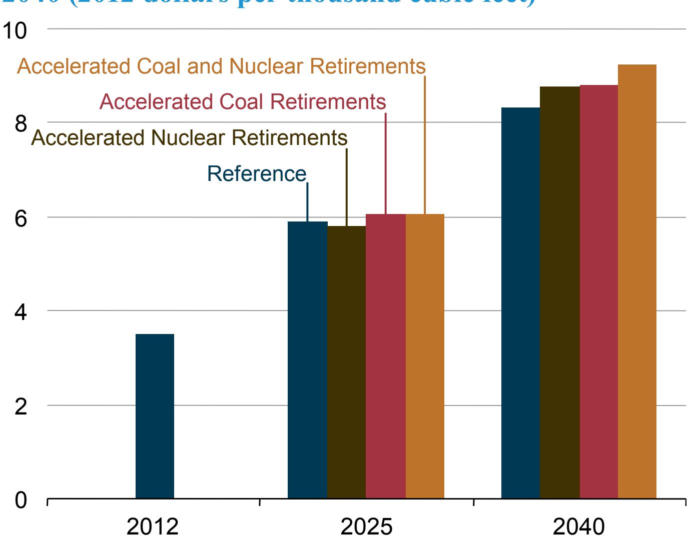


Figure IF6-6. Electric power sector carbon dioxide emissions in four cases, 2012-40 (million metric tons per year)

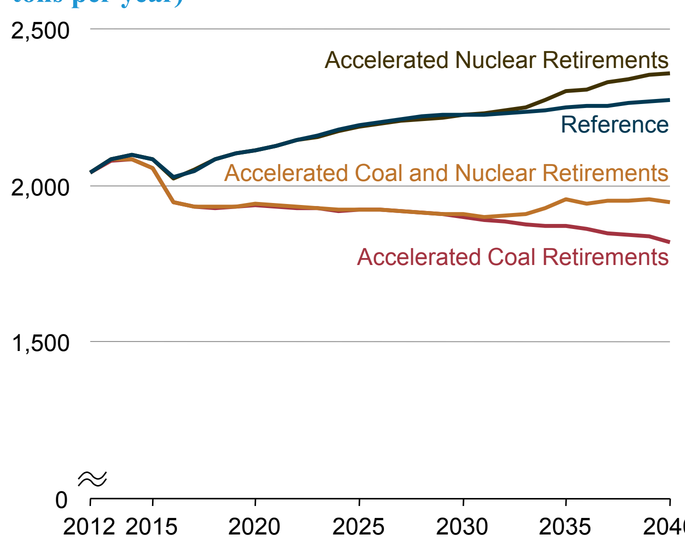
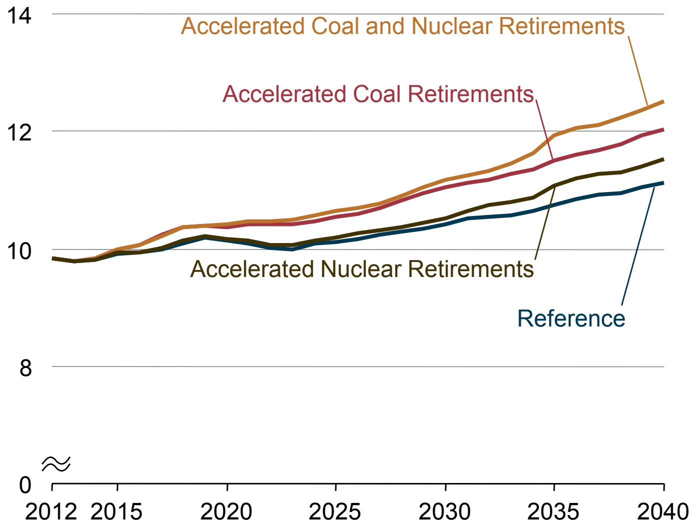


Figure IF6-7. Average retail electricity prices in four cases, 2012-40 (2012 cents per kilowatthour)



Effects on CO_2 emissions depend on the technology retired. Because a natural gas-fired combined-cycle plant emits less than half as much CO_2 as a plant fueled with pulverized coal, accelerated retirements of coal-fired plants result in lower CO_2 emissions compared with the Reference case. In contrast, because nuclear power plants emit no CO_2, accelerated retirements of nuclear power plants raise CO_2 emissions compared with the Reference case.

Table IF6-1. Average delivered natural gas prices, electricity prices, and carbon dioxide emissions in four cases, 2012, 2025, and 2040

Year and case	Average delivered natural gas price to power sector (2012 dollars per million Btu)	Retail electricity price (2012 cents per kilowatthour)	Electric power sector carbon dioxide emissions (million metric tons)
2012	3.44	9.8	2,039
2025			
Reference	5.76	10.1	2,194
Accelerated Coal Retirements	5.91	10.5	1,925
Accelerated Nuclear Retirements	5.69	10.2	2,188
Accelerated Coal and Nuclear Retirements	5.92	10.6	1,923
2040			
Reference	8.16	11.1	2,271
Accelerated Coal Retirements	8.60	12.0	1,821
Accelerated Nuclear Retirements	8.57	11.5	2,356
Accelerated Coal and Nuclear Retirements	9.03	12.5	1,946

Endnotes for IF6

Links current as of April 2014

1. Entergy, "Entergy to close, decommission Vermont Yankee" (Press Release, August 27, 2013; accessed March 25, 2014), http://www.entergy.com/news_room/newsrelease.aspx?NR_ID=2769.
2. Exelon Corporation, "Exelon to retire Oyster Creek generating station in 2019" (Press Release, December 8, 2010; accessed March 25, 2014), http://www.exeloncorp.com/newsroom/pr_20101208_Nuclear_OysterCreekRetirement.aspx.
3. M. Wallace and G.D. Banks, *Restoring U.S. Leadership in Nuclear Energy* (Center for Strategic & International Studies, Washington, DC, June 2013), http://csis.org/publication/restoring-us-leadership-nuclear-energy.
4. The U.S. Energy Information Administration analysis assumes competitive economics for electric power capacity, in which variable costs determine dispatch, and fixed costs must also be paid by electric sales revenue to continue operation over the long term.
5. Capacity payments provide units with revenue for being available to run in order to ensure reliability. Capacity payments can account for a significant portion of revenue for peak load plants, which do not run often and require financial incentives to remain available for dispatch.
6. U.S. Energy Information Administration, "Dark spreads measure returns over fuel costs of coal-fired generation," *Today In Energy* (February 20, 2013), http://www.eia.gov/todayinenergy/detail.cfm?id=10051.
7. U.S. Energy Information Administration, "Electric generator dispatch depends on system demand and the relative cost of operation," *Today In Energy* (August 17, 2012), http://www.eia.gov/todayinenergy/detail.cfm?id=7590.
8. U.S. Energy Information Administration, "Assumptions to AEO2014: Electricity Market Module" (forthcoming), http://www.eia.gov/forecasts/aeo/assumptions/.
9. S. Ferris, "Hatfield's Ferry Power Station quietly closes for good," *Herald Standard* (Uniontown, PA, October 20, 2013), http://www.heraldstandard.com/new_today/hatfield-s-ferry-power-station-quietly-closes-for-good/article_cd0133e1-9adb-58c2-8f8d-66769de34835.html. Installing control equipment does not guarantee that a plant will remain economical to continue operating. Retirement of the Hatsfield's Ferry power station in Pennsylvania was announced after installation of a $650 million FGD scrubber system in 2009. However, in the AEO2014 Reference case most coal-fired power plants continue operating despite the regulatory hurdle of MATS in 2016.
10. Electric Utility Cost Group (EUCG), via Nuclear Energy Institute, "Annual briefing for the financial community" (February 13, 2014), http://www.nei.org/Issues-Policy/Economics/Financial-Analyst-Briefings/Nuclear-Energy-in-2014-Status-and-Outlook.
11. The 2025 average price of natural gas price delivered to the electric power sector in the Accelerated Nuclear Retirements case is slightly lower than the price in the Reference case due to a decline in LNG export capacity additions. The retirement of nuclear capacity in the Accelerated Nuclear Retirements case after 2030 causes an increase in demand from the electric power sector, resulting in higher natural gas prices, and the anticipation of higher prices reduces the economic competitiveness of LNG export facilities, lowering LNG export projections. This results in lower natural gas prices in the Accelerated Nuclear Retirements case between 2022 and 2032, because less natural gas is exported. Demand from the power sector does not change significantly from the Reference case until significant amounts of nuclear capacity are retired.

Figure and table sources for IF6

Links current as of April 2014

Figure IF6-1. Cumulative retirements of coal-fired generating capacity in four cases, 2012-40. Projections: AEO2014 National Energy Modeling System, runs REF2014.D102413A, HCCSTOM.D012314A, HCLONUC.D012314A, and HIGHRESOURCE.D112913B.

Figure IF6-2. Cumulative retirements of nuclear generating capacity in three cases, 2012-40. Projections: AEO2014 National Energy Modeling System, runs REF2014.D102413A, LOWNUC14.D012314B, and HCLONUC.D012314A.

Figure IF6-3. Cumulative additions of electricity generating capacity by fuel in four cases, 2012-40: Projections: AEO2014 National Energy Modeling System, runs REF2014.D102413A, HCLONUC.D012314A, HCCSTOM.D012314A, and LOWNUC14.D012314B.

Figure IF6-4. Electricity generation by fuel in four cases, 2040. Projections: AEO2014 National Energy Modeling System, runs REF2014.D102413A, HCLONUC.D012314A, HCCSTOM.D012314A, and LOWNUC14.D012314B.

Figure IF6-5. Delivered price of natural gas to the electric power sector in four cases, 2012, 2025, and 2040. History: U.S. Energy Information Administration, *Monthly Energy Review September 2013,* DOE/EIA-0035 (2013/09) (Washington, DC, September 2013). Projections: AEO2014 National Energy Modeling System, runs REF2014.D102413A, HCLONUC.D012314A, HCCSTOM.D012314A, and LOWNUC14.D012314B.

Figure IF6-6. Electric power sector carbon dioxide emissions in four cases, 2012-40. Projections: AEO2014 National Energy Modeling System, runs REF2014.D102413A, HCLONUC.D012314A, HCCSTOM.D012314A, and LOWNUC14.D012314B.

Figure IF6-7. Average retail electricity prices in four cases, 2012-40. Projections: AEO2014 National Energy Modeling System, runs REF2014.D102413A, HCLONUC.D012314A, HCCSTOM.D012314A, and LOWNUC14.D012314B.

Table IF6-1. Average delivered natural gas prices, electricity prices, and carbon dioxide emissions in four cases, 2012, 2025, and 2040. History: U.S. Energy Information Administration, *Monthly Energy Review September 2013,* DOE/EIA-0035 (2013/09) (Washington, DC, September 2013). Projections: AEO2014 National Energy Modeling System, runs REF2014.D102413A, HCLONUC.D012314A, HCCSTOM.D012314A, and LOWNUC14.D012314B.

IF7. Renewable electricity projections show growth under alternative assumptions in AEO2014

In the AEO2014 Reference case, renewable electricity generation grows by 69% from 2012 to 2040, including an increase of more than 140% in generation from nonhydropower renewable energy sources. Renewables are collectively the fastest-growing source of electricity generation in the projection, with annual growth rates that exceed the growth rate for natural gas-fired generation. However, because renewables start from a relatively low 12% market share of total generation, their contribution to U.S. total electricity generation is just 16% in 2040 in the Reference case, well below the natural gas and coal shares of 35% and 32%, respectively (Figure IF7-1).

The AEO2014 Reference case is based on current laws and policies, as well as on known technology and demographic trends. Projections of nonhydropower [*1*] renewable electricity generation are sensitive to assumptions about government policies and external market factors. Key uncertainties affecting projected growth include expiration of policies that affect financial incentives for deployment or operation of particular technologies, the costs and performance of the technologies, the costs of competing generation sources, and macroeconomic conditions that affect growth in electricity demand (including GDP growth).

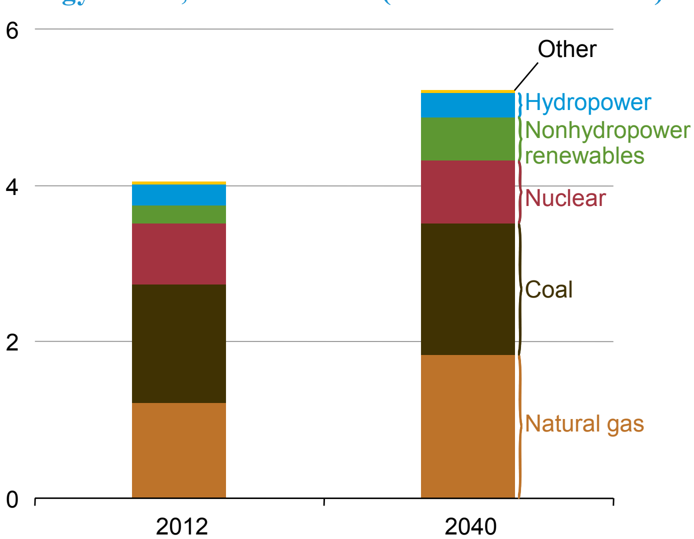
The renewable energy policy landscape is particularly dynamic compared to that of more-established energy sources, as new and existing policies continue to be created and adjusted at the federal, state, and local levels. In addition, policies that affect competing sources of generation, such as natural gas and coal, can have significant impacts on renewable generation projects. For example, placing an explicit or implicit value on carbon dioxide (CO_2) emissions would make the cost of operating fossil-fueled capacity higher, improving the relative economics of renewables.

From 2005 to 2012, nonhydropower renewable generation more than doubled, encouraged by policies such as federal tax credits and grants, state renewable portfolio standards (RPS), and a variety of other state and local policies such as rebates, tax incentives, financing assistance, net metering, and interconnection standards. For example, the federal production tax credit (PTC), which most recently applied to wind, geothermal, biomass, hydro, certain waste technologies, and marine energy projects under construction by the end of 2013, was first established by the Energy Policy Act of 1992. Since that time, the tax credit has been revised periodically—expiring several times and then subsequently being renewed. Most recently, the credit expired at the end of 2013 and has not been extended as of early 2014. Trade groups and renewable supporters continue to advocate for an extension to the 2013 deadline, but the AEO2014 Reference case assumes no such extension.

Assumptions about the cost and performance of renewable technologies also affect the projections, particularly as some renewable technologies become more economically competitive in some regions. Determination of future or even current technology costs can be a challenge. For example, in the case of solar photovoltaic (PV) technologies, there is enough variation among current projects in terms of geographic locations, technologies, developer experience, and regulatory frameworks that even the most carefully developed estimates will overstate actual costs for some projects and understate costs for others. While PV capital costs have declined over the past decade, there is continuing uncertainty about both the degree and pace of future cost declines.

Projections for generation with renewables are sensitive to the prices of competing generation sources and other market factors, particularly in later years of the projection period, when the projected trends in renewable generation are increasingly influenced by economic rather than policy factors. In some regions and projection years, renewable resources like wind or solar may represent the marginal source of capacity growth, which makes renewables sensitive to price swings in competing resources as well as to broader economic or market fluctuations. In order to address such uncertainties, AEO2014 includes alternative cases to provide insight regarding the direction and magnitude of sensitivities in the projections. Table IF7-1 shows key technology, policy, economic, and market uncertainties and shows how they are addressed in a selected group of AEO2014 alternative cases (described in more detail in Appendix E).

Figure IF7-1. Total U.S. electricity generation by energy source, 2012 and 2040 (billion kilowatthours)



The Low Renewable Technology Cost case assumes that renewable technology capital costs are 20% lower than in the Reference case. The No Sunset case assumes the extension of existing federal energy policies that contain sunset provisions—in particular the production and investment tax credits for certain renewable electricity generation technologies. The GHG25 case assumes a policy that applies a fee on carbon dioxide emissions (in 2012 dollars) starting at $25 per metric ton in 2015 and escalating by 5% per year to about $85 per metric ton in 2040. The High Oil and Gas Resource case adjusts oil and gas resource and productivity assumptions that result in natural gas prices to the electric power sector in 2040 that are 37% lower than in the Reference case. The Low Oil and Gas Resource case adjusts assumptions about oil and gas resources that result in natural gas prices to the electric power sector in 2040 that are 33%

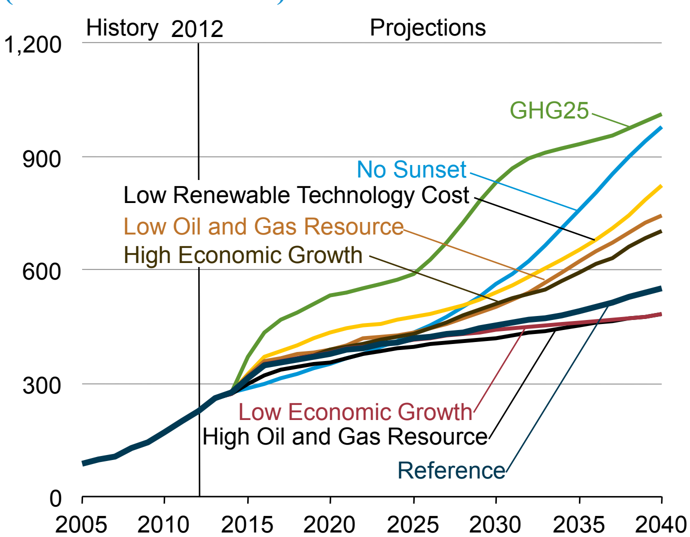
higher than in the Reference case. The High Economic Growth and Low Economic Growth cases assume higher and lower levels of real GDP growth from 2012 to 2040 than in the Reference case.

Figure IF7-2 shows projected total nonhydropower renewable generation from 2012 to 2040 in the selected alternative cases. The results vary significantly, particularly in the later years of the projection. For example, in the GHG25 case total nonhydropower renewable generation in 2040 is 83% higher than in the Reference case, and in the High Oil and Gas Resource case total nonhydropower renewable generation in 2040 is 12% lower than in the Reference case.

Some of the assumptions used in the AEO2014 alternative cases can lead to significant increases in long-term growth of renewable electricity generation. However, alternative cases with assumptions that are less favorable to renewables growth, such as the Low Economic Growth case (with slower electricity demand growth) and the High Oil and Gas Resource case (with lower natural gas prices) are unlikely to result in renewable projections that fall drastically below those in the Reference case—in large part because state renewable portfolio standards (RPS) effectively establish a floor for generation with renewables. RPS policies generally require that a minimum share of generation must come from renewable sources, and even with slow load growth or competition from low-cost alternative generation resources, renewable generation must be sufficient to meet the RPS target. On the other hand, as renewable generation sources become increasingly competitive after 2025, a favorable shift in assumptions may result in an impact that does not have a limit on the upper bound, allowing for stronger growth in renewable generation than is projected in the Reference case.

In addition, long-term projections are more sensitive to changes in assumptions than are near-term projections. Although the range of renewable generation in 2040 across the alternative cases is large, the 2025 projections for total renewable generation are within 15% of the Reference case in all the alternative cases except for the GHG25 case. Near-term growth in renewable generation is constrained by a combination of factors that generally hold across most sensitivity analyses: growth in electricity demand continues at a relatively low annual rate (less than 1% per year in the Reference case) compared with historical levels, and generating capacity required to meet demand and reserve requirements in many regions already exceeds near-term requirements at the start of the projection period. As a result, demand for new generating capacity of any type in the first decade of the projection is minimal in most regions. From 2012 to 2025, total generating capacity—including renewables, fossil fuels, and nuclear—increases by only 4%. However, as renewable technologies become more economically competitive, they capture a larger share of the growing market. In addition, even with low rates of electricity demand growth, the presence of a significant and growing fee on CO_2 emissions creates enough pressure early in the projection period to spur significant growth of renewable generation in the near term.

Figure IF7-2. Nonhydropower renewable electricity generation in eight cases, 2005-40 (billion kilowatthours)



Alternative assumptions that lead to greater penetration of electricity markets by renewable energy sources—namely, those in the No Sunset, Low Renewable Technology Cost, GHG25, Low Oil and Gas Resource, and High Economic

Table IF7-1. Sources of uncertainty and variation in AEO2014 projections for renewable electricity generation

Key uncertainties	Selected AEO2014 alternative cases	Uncertainties not addressed in AEO2014 alternative cases
Technology: Cost assumptions for renewable technologies.	Low Renewable Technology Cost	Breakthroughs in new or emerging renewable (e.g., wave/tide/ocean) or complementary (e.g., storage) technologies
Policy: Current policies may not expire as scheduled; future policies may impose direct or indirect fees on carbon dioxide emissions.	No Sunset GHG25 (carbon dioxide fee case)	Existing policies not explicitly modeled in AEO2014 that are more specific or geographically specialized (e.g., net metering, local rebate programs, and technology-specific set-asides in state RPS programs); other new policies that could be introduced
Macroeconomics and prices: Macroeconomic growth rates and natural gas prices.	High Oil and Gas Resource Low Oil and Gas Resource High Economic Growth Low Economic Growth	Competition from other fuels; sector- or region-specific economic factors; unexpected shifts in demand

Growth cases—do not have proportionate effects on all renewable technologies (Figures IF7-3 through IF7-6). Generation from solar and wind installations generally increases by more compared with the Reference case than does generation from biomass, waste, and geothermal sources. Solar generation in 2040 in most of the alternative cases is more than double the Reference case level. Wind starts from a much larger installed capacity base, so the percentage growth in wind generation is lower than for solar, but in all five alternative cases wind generation in 2040 is at least 20% higher than projected in the Reference case.

Solar and wind energy are expected to remain the primary sources of renewable capacity growth. Although geothermal, waste, and biomass resources have some favorable characteristics compared to wind and solar, such as the ability to provide operator-dispatched power, each has significant limitations. The limitations include a limited resource base (geothermal, waste) or relatively high capital and/or fuel costs (biomass). Although wind and solar will continue to be capital-intensive technologies, they are expected to achieve cost reductions that—along with a larger resource base—result in higher growth than other renewables under favorable conditions (such as placement of an explicit or implicit value on CO_2 emissions, or high natural gas prices). However, solar and wind resources also vary in availability and quality by region, and generation facilities are likely to be concentrated in the more favorable regions.

Even in the alternative cases that result in higher levels of market penetration for renewable generation technologies, the results are limited by the selection of technologies currently modeled by the U.S. Energy Information Administration. The AEO2014 alternative cases cannot be used to evaluate potential technologies that are not characterized in the National Energy Modeling

Figure IF7-3. Electricity generation from wind power in eight cases, 2012, 2020, 2030, and 2040 (billion kilowatthours)

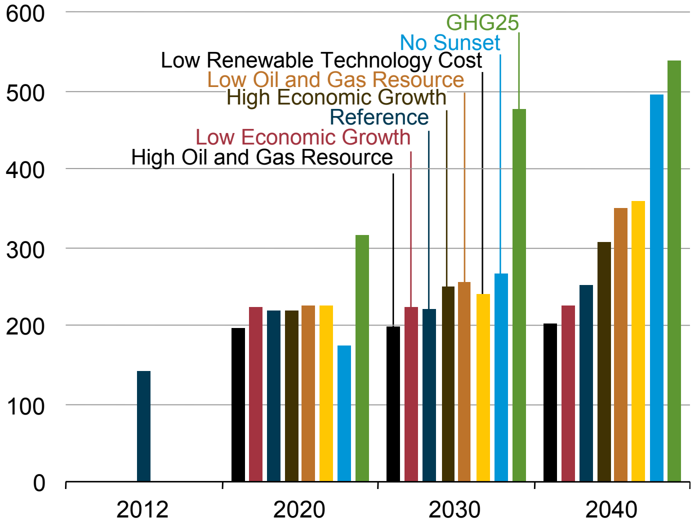


Figure IF7-4. Electricity generation from solar power in eight cases, 2012, 2020, 2030, and 2040 (billion kilowatthours)

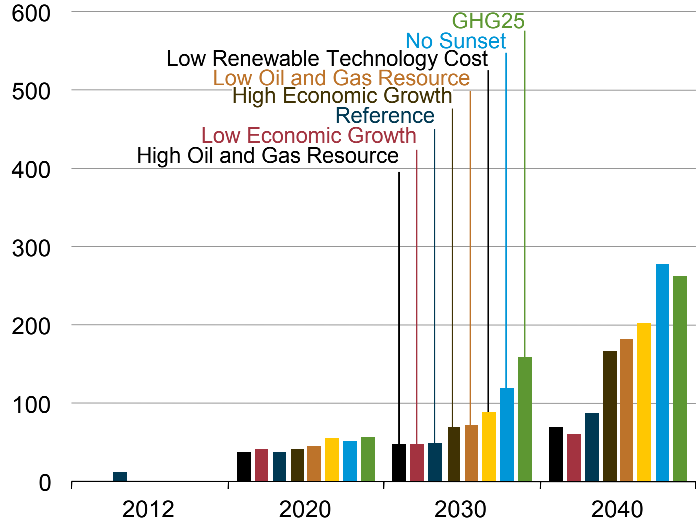


Figure IF7-5. Electricity generation from geothermal power in eight cases, 2012, 2020, 2030, and 2040 (billion kilowatthours)

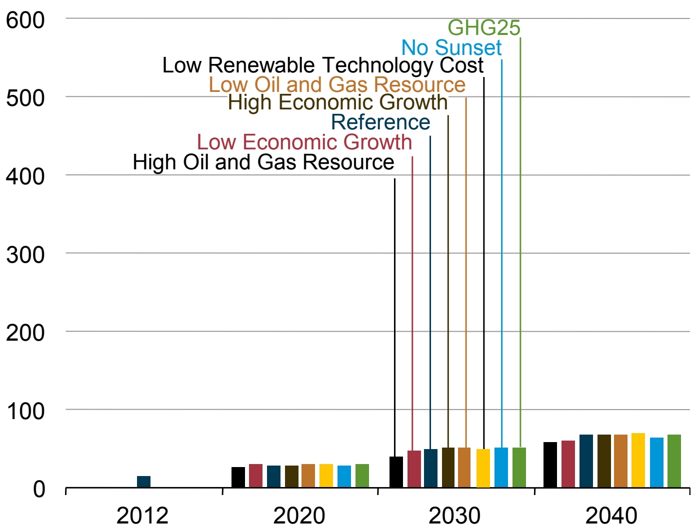
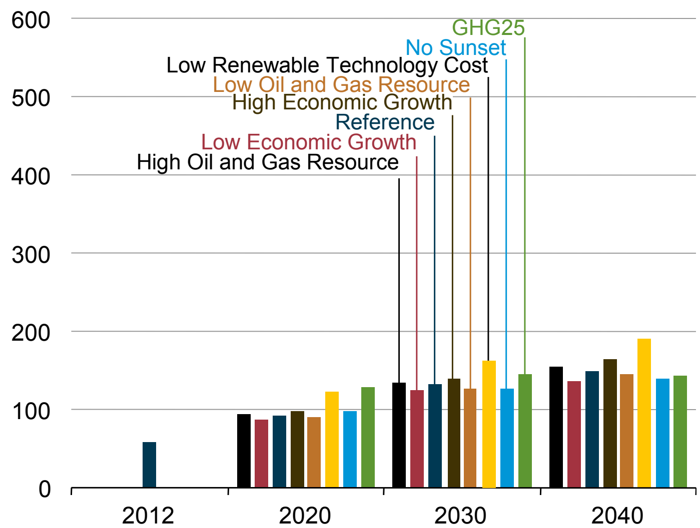


Figure IF7-6. Electricity generation from biomass and waste power in eight cases, 2012, 2020, 2030, and 2040 (billion kilowatthours)



System. Some emerging renewable technologies not included in AEO2014 include engineered geothermal systems, marine hydrokinetics (such as wave energy), in-stream hydroelectric, and hybrid solar thermal combined cycle.

Similarly, no new electricity storage technologies are included in the projections. Electricity storage represents one of several options for accommodating high levels of intermittent generation from wind and solar resources. Because such technologies, other than pumped hydro storage, generally are either in early stages of development or not yet commercially established, impacts on electricity markets in the near- to mid-term period are difficult to model.

The AEO2014 alternative cases typically examine the effects of changing single assumptions within a moderate range of uncertainty, and they are not intended to be interpreted as bounding cases. For example, a compound case incorporating high natural gas prices, low renewable technology costs, and an explicit or implicit value for CO_2 emissions could be expected to result in additional renewable generation growth, although the impact would not necessarily be the sum of the results of the individual cases. The same could be true if any of the individual alternative cases were examined using different assumptions—for example, if renewable technology costs were assumed to be 50%, rather than 20%, below the costs used in the Reference case.

Endnotes for IF7

Links current as of April 2014

1. Hydropower has resource-specific characteristics that separate it from other renewable energy sources. It is projected to remain close to current capacity and generation levels in the cases considered here.

Figure and table sources for IF7

Links current as of April 2014

Figure IF7-1. Total U.S. electricity generation by fuel, 2012 and 2040: History: U.S. Energy Information Administration, *Monthly Energy Review September 2013,* DOE/EIA-0035 (2013/09) (Washington, DC, September 2013). Projections: AEO2014 National Energy Modeling System, run REF2014.D102413A.

Table IF7-1. Sources of uncertainty and variation in AEO2014 projections for renewable electricity generation: U.S. Energy Information Administration.

Figure IF7-2. Nonhydropower renewable electricity generation in eight cases, 2005-40: History: U.S. Energy Information Administration, *Monthly Energy Review September 2013,* DOE/EIA-0035 (2013/09) (Washington, DC, September 2013). **Projections:** AEO2014 National Energy Modeling System, runs REF2014.D102413A, CO2FEE25.D011614A, NOSUNSET.D121713A, LCR_2014.D120613A, LOWRESOURCE.D112913A, HIGHRESOURCE.D112913B, LOWMACRO.D112913A, and HIGHMACRO.D112913A.

Figure IF7-3. Electricity generation from wind power in eight cases, 2012, 2020, 2030, and 2040: History: U.S. Energy Information Administration, *Monthly Energy Review September 2013,* DOE/EIA-0035 (2013/09) (Washington, DC, September 2013). **Projections:** AEO2014 National Energy Modeling System, runs REF2014.D102413A, CO2FEE25.D011614A, NOSUNSET.D121713A, LCR_2014.D120613A, LOWRESOURCE.D112913A, HIGHRESOURCE.D112913B, LOWMACRO.D112913A, and HIGHMACRO.D112913A.

Figure IF7-4. Electricity generation from solar power in eight cases, 2012, 2020, 2030, and 2040: History: U.S. Energy Information Administration, *Monthly Energy Review September 2013,* DOE/EIA-0035 (2013/09) (Washington, DC, September 2013). **Projections:** AEO2014 National Energy Modeling System, runs REF2014.D102413A, CO2FEE25.D011614A, NOSUNSET.D121713A, LCR_2014.D120613A, LOWRESOURCE.D112913A, HIGHRESOURCE.D112913B, LOWMACRO.D112913A, and HIGHMACRO.D112913A.

Figure IF7-5. Electricity generation from geothermal power in eight cases: History: U.S. Energy Information Administration, *Monthly Energy Review September 2013,* DOE/EIA-0035 (2013/09) (Washington, DC, September 2013). **Projections:** AEO2014 National Energy Modeling System, runs REF2014.D102413A, CO2FEE25.D011614A, NOSUNSET.D121713A, LCR_2014.D120613A, LOWRESOURCE.D112913A, HIGHRESOURCE.D112913B, LOWMACRO.D112913A, and HIGHMACRO.D112913A.

Figure IF7-6. Electricity generation from biomass and waste power in eight cases: History: U.S. Energy Information Administration, *Monthly Energy Review September 2013,* DOE/EIA-0035 (2013/09) (Washington, DC, September 2013). **Projections:** AEO2014 National Energy Modeling System, runs REF2014.D102413A, CO2FEE25.D011614A, NOSUNSET.D121713A, LCR_2014.D120613A, LOWRESOURCE.D112913A, HIGHRESOURCE.D112913B, LOWMACRO.D112913A, and HIGHMACRO.D112913A.

IF8. Implications of low electricity demand growth

Although electricity demand fell in only three years between 1950 and 2007, it declined in four of the five years between 2008 and 2012. The largest drop occurred in 2009 (Figure IF8-1). One contributing factor was the steep economic downturn from late 2007 through 2009, which led to a large drop in electricity sales in the industrial sector. Other factors, such as efficiency improvements associated with new appliance standards in the buildings sectors and overall improvement in the efficiency of technologies powered by electricity, have slowed electricity demand growth and may contribute to slower growth in the future, even as the U.S. economy continues its recovery.

In the Reference case, which assumes no new efficiency standards beyond those already in place or announced as final for future implementation as of 2012, total electricity use grows by an average of less than 1% per year from 2012 to 2040. Demand grows across all sectors, with average annual increases in the industrial sector (0.9% per year) slightly higher than those in the residential and commercial sectors (0.7% and 0.8% per year, respectively). As a result of rising demand, 351 gigawatts (GW) of new electricity generating capacity is added from 2012 to 2040, electricity generation increases by 29%, and carbon dioxide (CO_2) emissions from the electric power sector increase by 11%.

To examine the energy implications of slower growth of electricity demand, AEO2014 includes a Low Electricity Demand case, in which annual electricity demand in 2040 is only slightly higher than the 2012 level of 3.8 trillion kilowatthours (kWh).

Low Electricity Demand case

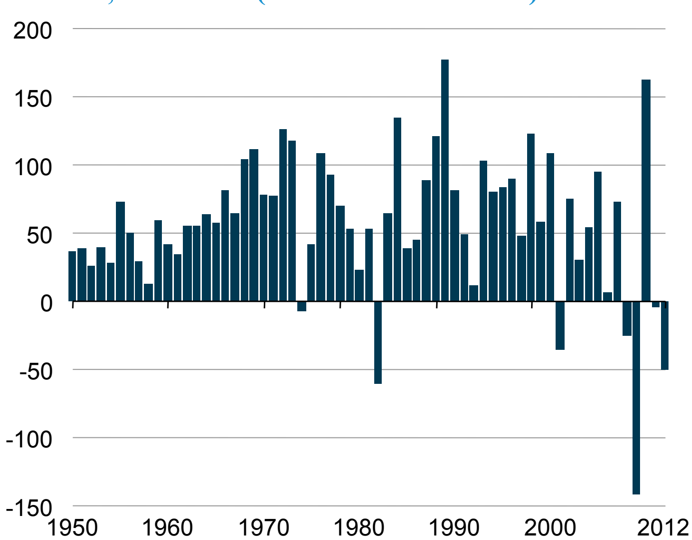
Electricity demand growth depends on economic growth, relative energy prices, and technology choices in the end-use sector, among other factors. Changes in electricity demand result in corresponding changes in electricity generation and the mix of technologies used to meet demand.

The Low Electricity Demand case was developed by assuming changes in technology choices and higher efficiency in the end-use sectors. To limit the number of competing influences, macroeconomic and fuel supply assumptions were unchanged from those in the Reference case. The goals for the Low Electricity Demand case were to identify a combination of technologies that would result in flat demand, and to examine the impacts of stagnant demand on future needs for electricity generation and supply.

The Low Electricity Demand case uses the assumptions incorporated in the Best Available Demand Technology case for both the residential and the commercial sectors, as described in Appendix E and the Market Trends section of this report. The Best Available Demand Technology case assumes that all future equipment purchases in the residential and commercial sectors will be made from a menu of technologies that includes only the most efficient models available in a particular year, regardless of cost. Building shell efficiencies also are assumed to improve relative to the Reference case, and distributed generation costs are assumed to decline much faster than in the Reference case. In addition to those assumptions, the Low Electricity Demand case assumes higher energy savings for electric motors in pumps, fans, and air compressors used in the industrial sector compared with the Reference case. Those adjustments reduce total electric power consumption by electric motors slightly less than 20% over the course of the projection. Although technically plausible, such a drop in electric motor energy usage may not represent a likely path for motor development.

As a result of changes across all end-use sectors in the Low Electricity Demand case, retail electricity sales in 2040 are roughly the same as in 2012. Industrial sales grow slightly from 2012 levels, but a decline in residential sales offsets that growth. Because the distributed generation assumptions in the buildings sector result in higher investment in end-use renewable capacity and generation relative to the Reference case, direct-use generation increases, and there is a 7% increase in total electricity consumption from 2012 to 2040, as compared with 29% in the Reference case (Figure IF8-2).

Figure IF8-1. Annual changes in U.S. electricity demand, 1950-2012 (billion kilowatthours)



Analysis results

Electricity generation capacity

In the Low Electricity Demand case, little new capacity is added in the power sector after planned capacity additions are completed (Figure IF8-3). A significant amount of renewable capacity is added in the end-use sectors as a result of the lower cost assumptions for distributed solar photovoltaics, and a smaller amount of renewable capacity (19% of total renewable additions) is added in the power sector to meet renewable portfolio standards. Total natural gas capacity added is only one-quarter of the amount in the AEO2014 Reference case. Even more so than in the Reference case, there are few new additions of coal or nuclear capacity beyond those already under construction.

With lower demand for electricity, a total of 110 GW of older coal-fired generating capacity is retired between 2013 and 2040 in the Low Electricity Demand case, more than double the 51 GW retired in the Reference case (Figure IF8-4). Most of the retirements occur early in the projection, due to the timing of the Mercury and Air Toxics Standards (MATS), which require a decision to retire or retrofit coal plants to meet environmental standards by 2016. A total of 100 GW of oil- and gas-fired capacity is retired between 2013 and 2040 in the Low Electricity Demand case, compared with 40 GW in the Reference case.

Electricity generation

Electricity generation in 2040 is 17% lower in the Low Electricity Demand case than in the Reference case, with natural gas-fired generation 472 billion kWh lower and coal-fired generation 343 billion kWh lower. Figure IF8-5 shows total electricity generation from the electric power sector and the end-use sectors, with the contributions broken out for natural gas and renewable generation to display the relative levels of generation from the end-use sectors. As in the Reference case, natural gas-fired generation overtakes coal-fired generation by the end of the projection period, but overall shares for both fuels are lower than in the Reference case. In 2040, the coal share of total generation drops from 37% in 2012 to 32% in the Reference case, and to 31% in the Low Electricity Demand case. The natural gas share, which increases from 30% in 2012 to 35% in 2040 in the Reference case, grows to only 32% in 2040 in the Low Electricity Demand case. Because there is less need for new generating capacity, there is less opportunity for growth in natural gas-fired generation from new plants.

Nuclear electricity generation is slightly lower in the Low Electricity Demand case than in the Reference case, as a result of fewer new builds, but it provides a slightly higher share of total generation than in the Reference case. Renewable generation grows by 60% from 2012 to 2040 in the Low Electricity Demand case, slightly less than the 69% growth in the Reference case, as a large

Figure IF8-2. U.S. total electricity demand by sector in two cases, 2012 and 2040 (billion kilowatthours)

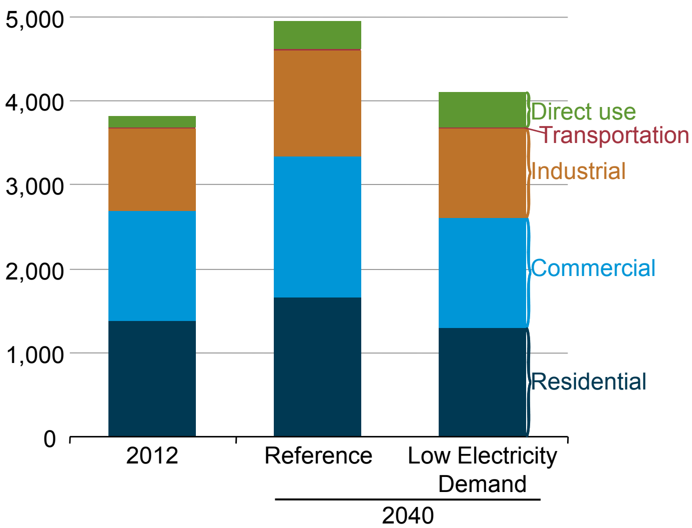


Figure IF8-3. Electricity capacity additions by fuel type in two cases, 2013-40 (gigawatts)

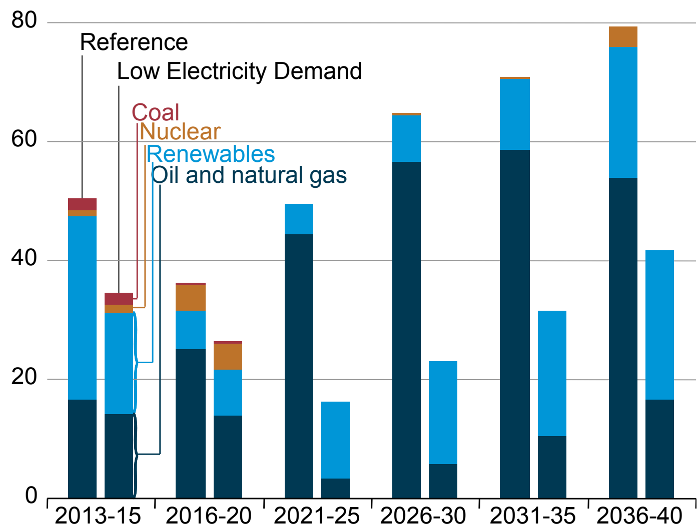


Figure IF8-4. Electric power sector cumulative retirements in two cases, 2013-40 (gigawatts)

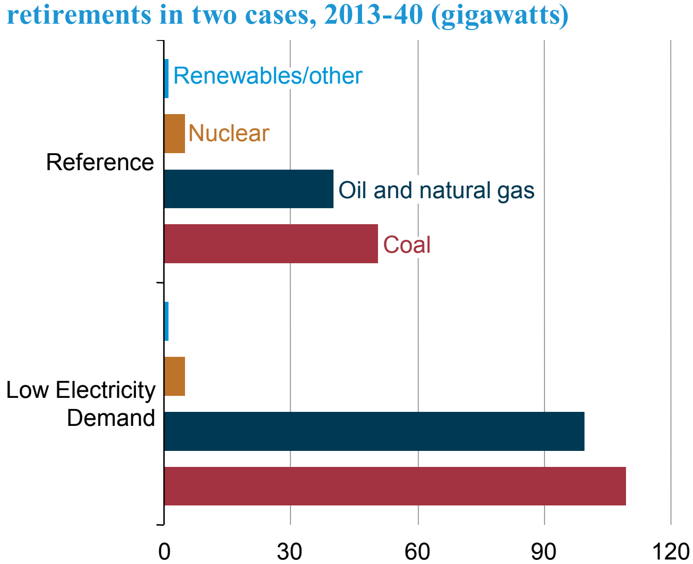
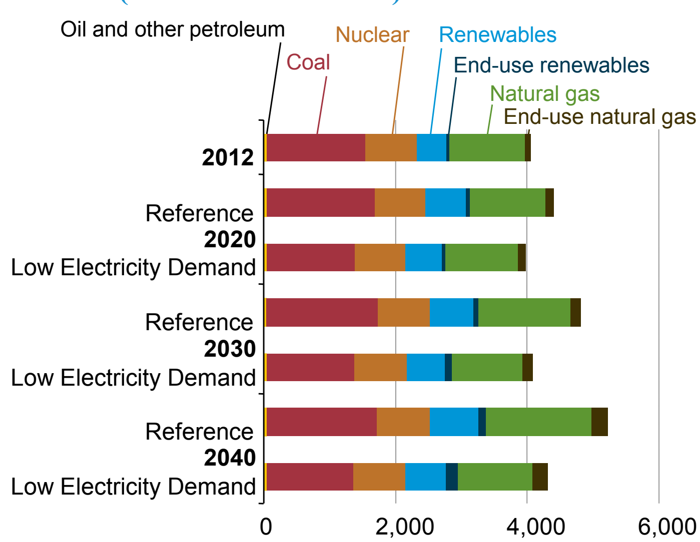


Figure IF8-5. Electricity generation in two cases, 2012-40 (billion kilowatthours)



increase in end-use sector renewable generation offsets much of the decline in renewable generation in the electric power sector compared with the Reference case.

Emissions

The lower level of generation from fossil fuels in the Low Electricity Demand case results in lower greenhouse gas emissions. In 2020, power sector CO_2 emissions are 16% lower than in the Reference case, and in 2040 they are 22% lower (Figure IF8-6). Emissions of other pollutants (sulfur dioxide, nitrogen oxides, and mercury) are also lower than in the Reference case, in proportion to coal-fired generation. The additional retirements of coal-fired capacity in the Low Electricity Demand case begin to occur in 2016, when MATS takes effect. With lower demand and prices for electricity than in the Reference case, it is less economical to install retrofits to comply with the MATS standards. As a result, fewer environmental controls are added.

Regional impacts

The mix of fuels used to meet U.S. demand for electricity varies across the country, and the initial mix can affect regional projections in the different cases. In general, the West is more reliant on natural gas and renewable generation, the upper Midwest and Central parts of the country are more reliant on coal, the Northeast is more reliant on natural gas and nuclear power, and in the Mid-Atlantic and Southeast there is a mix of generation from coal, nuclear power, and natural gas.

Currently, most coal-fired capacity is installed in two North American Electric Reliability Corporation (NERC) regions: the SERC Reliability Corporation (SERC) region, which covers the Southeast region, and the Reliability First Corporation (RFC) region, which includes most of the Mid-Atlantic and Ohio Valley region [*1*] (Figure IF8-7). Most of the coal retirements in both the Reference case and the Low Electricity Demand case occur in those regions.

In the RFC region, retirements of coal-fired capacity in the Low Electricity Demand case are double those in the Reference case, and in the SERC region they are nearly triple those in the Reference case. The RFC and SERC regions also contain 67% of the country's current nuclear capacity. However, as in other regions, there are no additional retirements of nuclear capacity in the Low Electricity Demand case relative to the Reference case. As a result, nuclear generation levels are similar in the two cases, and they make up a higher share of the total generation when electricity demand is lower. In SERC, the coal share of total generation in 2040 declines from 38% in the Reference case to 34% in the Low Electricity Demand case, and the nuclear share grows from 23% in the Reference case to 28%. Similarly in the RFC region, the 2040 coal share drops from 44% in the Reference case to 40% in the Low Electricity Demand case, and the 2040 nuclear share rises from 21% to 26%. In both regions the natural gas share also declines slightly in the Low Electricity Demand case relative to the Reference case, because fewer new natural gas-fired power plants are built. Additional retirements of older oil and gas units have less effect on generation than do retirements of coal units, because the oil and gas units typically operate less frequently throughout the year.

In contrast, in regions where there may not be more economical baseload technologies available, coal continues to provide most of the generation needs in 2040, even when electricity demand is assumed to be flat. In the Midwest Reliability Organization (MRO) region, coal-fired plants provided 60% of total generation in 2012, and they still provide 52% in the Reference case and 55% in the Low Electricity Demand case in 2040. With few new natural gas-fired additions projected in the Low Electricity Demand case, coal-fired power plants continue to provide a large portion of the region's total electricity generation.

Figure IF8-6. Carbon dioxide emissions in the electric power sector in two cases, 2012-40 (million metric tons carbon dioxide)

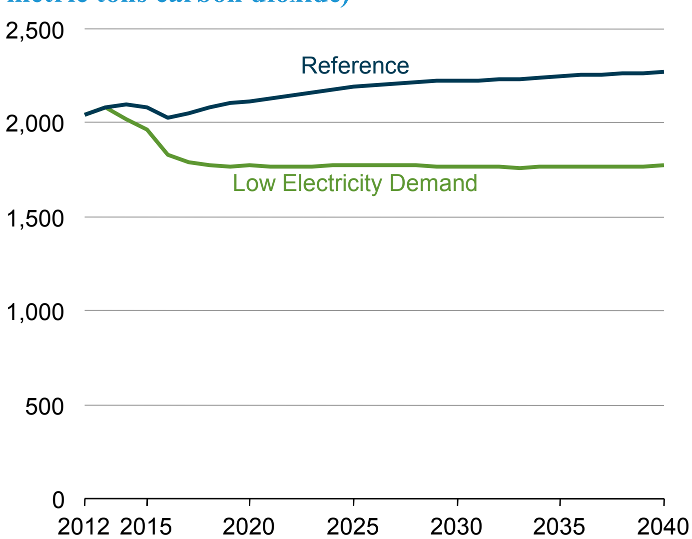
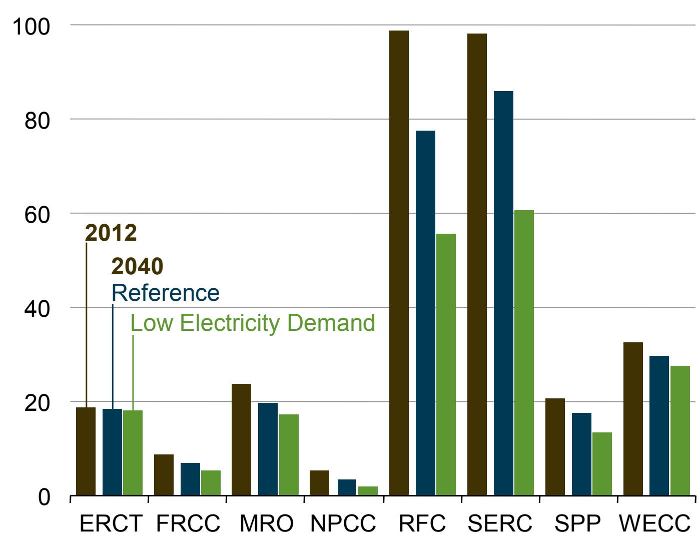


Figure IF8-7. Coal-fired generating capacity by NERC region in two cases, 2012 and 2040 (gigawatts)



Endnotes for IF8

Links current as of April 2014

1. See Appendix F for a map of the Electricity Market Model (EMM) regions. For this discussion, results at the EMM level have been aggregated to the larger NERC regions on which they are based.

Figure sources for IF8

Links current as of April 2014

Figure IF8-1. Annual changes in U.S. electricity demand, 1950-2012: U.S. Energy Information Administration, *Monthly Energy Review September 2013,* DOE/EIA-0035 (2013/09) (Washington, DC, September 2013).

Figure IF8-2. U.S. total electricity demand by sector in two cases, 2012 and 2040: History: U.S. Energy Information Administration, *Monthly Energy Review September 2013,* DOE/EIA-0035 (2013/09) (Washington, DC, September 2013). **Projections:** AEO2014 National Energy Modeling System, runs REF2014.D102413A and FLAT.D010914A.

Figure IF8-3. Electricity capacity additions by fuel type in two cases, 2013-40: Projections: AEO2014 National Energy Modeling System, runs REF2014.D102413A and FLAT.D010914A.

Figure IF8-4. Electric power sector cumulative retirements in two cases, 2013-40: Projections: AEO2014 National Energy Modeling System, runs REF2014.D102413A and FLAT.D010914A.

Figure IF8-5. Electricity generation in two cases, 2012-40: History: U.S. Energy Information Administration, *Monthly Energy Review September 2013,* DOE/EIA-0035 (2013/09) (Washington, DC, September 2013). **Projections:** AEO2014 National Energy Modeling System, runs REF2014.D102413A and FLAT.D010914A.

Figure IF8-6. Carbon dioxide emissions in the electric power sector in two cases, 2012-40: History: U.S. Energy Information Administration, *Monthly Energy Review September 2013,* DOE/EIA-0035 (2013/09) (Washington, DC, September 2013). **Projections:** AEO2014 National Energy Modeling System, runs REF2014.D102413A and FLAT.D010914A.

Figure IF8-7. Coal-fired generating capacity by NERC region in two cases, 2012 and 2040: History: U.S. Energy Information Administration (EIA), Form EIA-860, "Annual Electric Generator Report" (preliminary). **Projections:** AEO2014 National Energy Modeling System, runs REF2014.D102413A and FLAT.D010914A.

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 2014* (AEO2014) 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 technological progress, and policy changes.

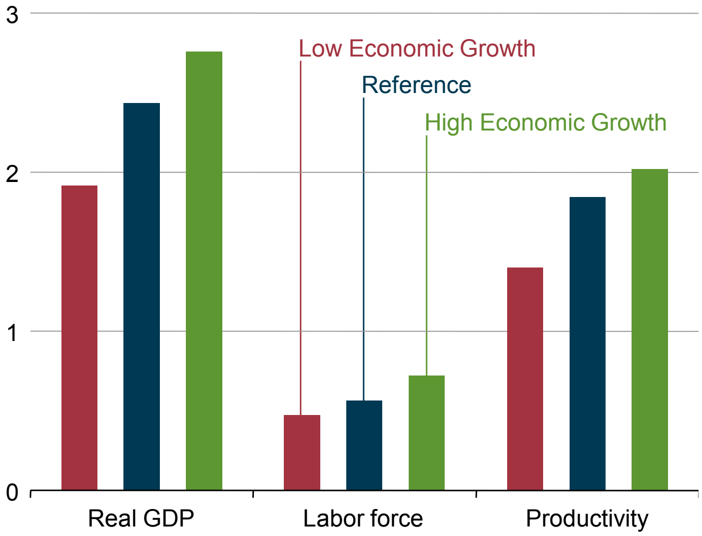
While energy markets are complex, energy models are simplified representations of energy production and consumption, regulations, and producer and consumer behavior. Projections are highly dependent on the data, methodologies, model structures, and assumptions used in their development. Behavioral characteristics 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 AEO2014 projections are addressed through alternative cases.

EIA has tried 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.

Growth in business fixed investment offsets slow growth in labor force

Figure MT-1. Average annual growth rates of real GDP, labor force, and productivity in three cases, 2012-40 (percent per year)



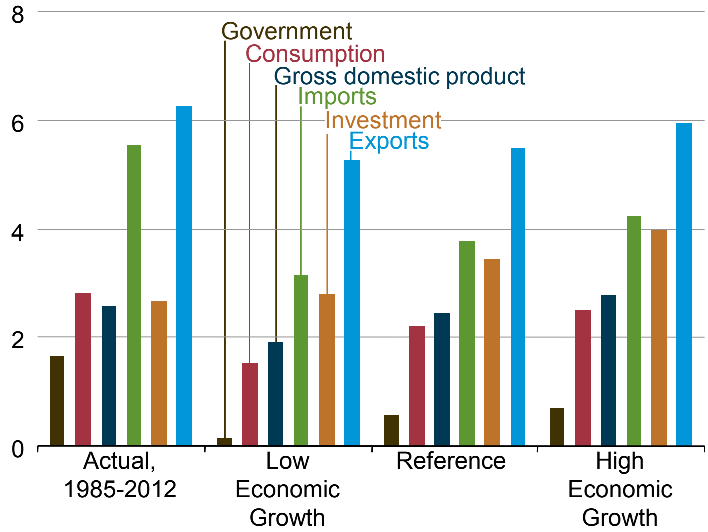
Growth in the output of the U.S. economy depends on increases in the labor force, growth of capital stock, and improvements in productivity. In the *Annual Energy Outlook 2014* (AEO2014) Reference case, U.S. labor force growth slows over the projection period as the baby boom generation starts to retire, but projected growth in business fixed investment and spending on research and development offsets the slowdown in labor force growth. Annual growth in real gross domestic product (GDP) averages 2.4%/year from 2012 to 2040 in the Reference case (Figure MT-1), 0.3 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 0.8%/year, from 134 million in 2012 to 169 million in 2040. The manufacturing share of total employment continues to decline, from 9% in 2012 to 7% in 2040.

Real consumption growth averages 2.2%/year in the Reference case. From 2012 to 2040, the share of GDP accounted for by personal consumption expenditures varies between 66% and 71%, and the share spent on services rises mainly as a result of increasing expenditures on health care. The share of GDP devoted to business fixed investment ranges from 10% to 16% of GDP through 2040.

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

Economic activity varies considerably across the economic growth cases

Figure MT-2. Average annual growth rates for real output and its major components in three cases, 2012-40 (percent per year)



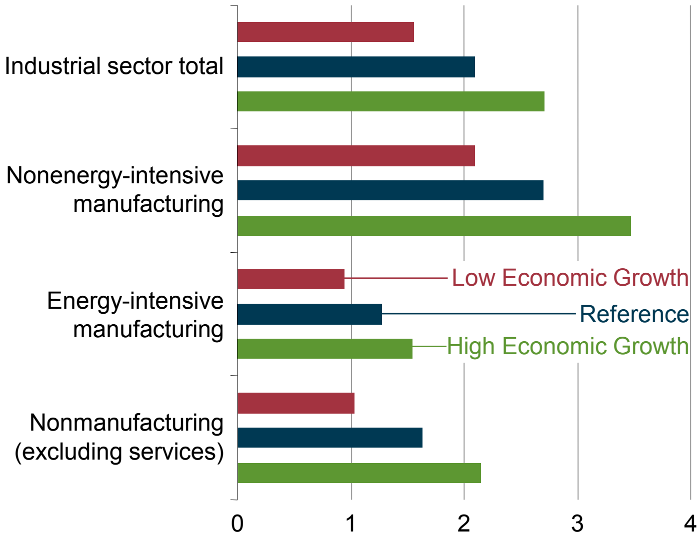
AEO2014 presents three economic growth cases: Reference, High, and Low (Figure MT-2). The High Economic Growth case assumes higher growth and lower inflation, relative to the Reference Case, and the Low Economic Growth case assumes lower growth and higher inflation. The short-term outlook (five years) in each case represents current views of economic activity in the United States and the rest of the world, the impacts of fiscal and monetary policies, and potential risks to economic activity. The long-term outlook includes smooth economic growth and assumes 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 2012 to 2040 in the Reference case is 2.4%, as compared with 2.8% in the High Economic Growth case and 1.9% in the Low Economic Growth case.

Figure MT-2 compares the average annual growth rates for output and its major components in each of the three cases. Compared with the 1985-to-2012 period, investment growth from 2012 to 2040 will be faster in all three cases, whereas consumption, government expenditures, imports, and exports will grow more slowly in all three cases. Opportunities for trade will expand in all three cases, resulting in real trade surpluses that continue to grow throughout the projection period.

For energy-intensive industries, output growth is strong early, then slows after 2025

Figure MT-3. Average annual growth rates of shipments for the industrial sector and its components in three cases, 2012-40 (percent per year)



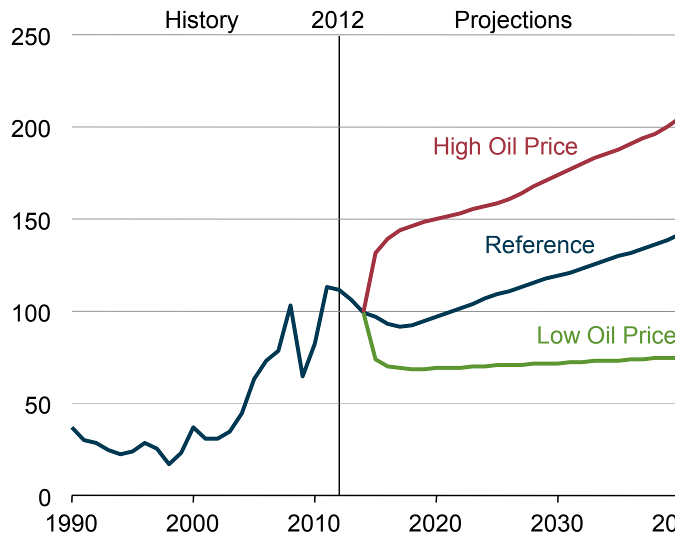
With a rapidly growing service sector and imports meeting a large share of demand for goods in recent decades, industrial sector shipments have expanded more slowly than the overall economy [*1*]. In the AEO2014 Reference case, real value of shipments for all goods and services [*2*] grows by 2.0% from 2012 to 2040, for the industrial sector by 2.1%/year, and for the service sector by 2.0%/year. Industrial sector manufacturing grows by 2.3%/year and nonmanufacturing by 1.6%/year (Figure MT-3).

The Reference case shows two distinct periods of growth, and the energy-intensive industries display the sharpest contrast between the periods. With increased shale gas production affecting U.S. competitiveness, growth in U.S. manufacturing output accelerates through 2025. From 2012 to 2025, real GDP grows by an average of 2.5%/year, and the industrial sector grows by 2.8%/year. After 2025, industrial output growth slows as a result of increased foreign competition and rising energy prices, with energy-intensive industries showing the largest slowdowns—from a 2012-25 average of 2.0%/year to a 2025-40 average of 0.7%/year. The 2012-40 output growth rates vary among industries, with iron and steel averaging 0.9%/year and the cement industry 2.5%/year.

Industrial production growth is strongly linked to exports, along with consumer demand and investment. Declining exchange rates, combined with modest escalation in unit labor costs, increase U.S. exports in the projection. From 2012 to 2040, real exports of goods and services increase by an average of 5.5%/year, while real imports of goods and services grow by an average of 3.8%/year.

Range of oil price cases represents uncertainty in world oil markets

Figure MT-4. North Sea Brent crude oil spot prices in three cases, 1990-2040 (2012 dollars per barrel)



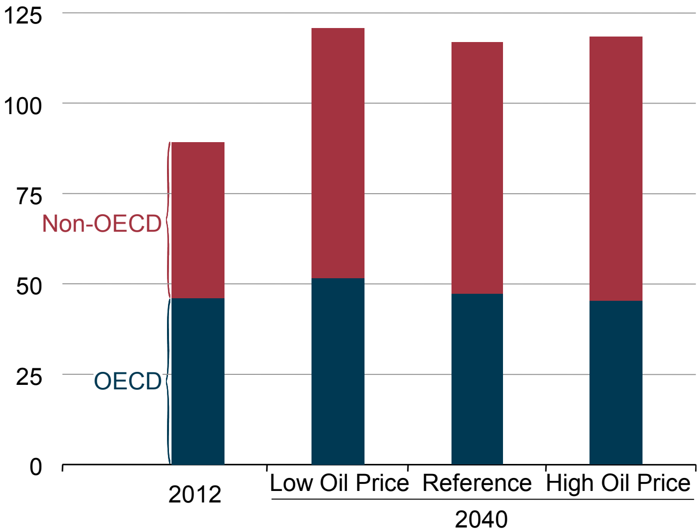
In AEO2014 the North Sea Brent crude oil price is tracked as the main benchmark for world oil prices. In 2013, the West Texas Intermediate (WTI) crude oil price continued to trade at a discount relative to other world oil prices. With refineries running at high levels through August 2013, the discount narrowed as a result of new oil transportation infrastructure from the market center for WTI prices in Cushing, Oklahoma. The discount widened from September to December 2013, however, as lower 48 production continued to grow and refinery utilization returned to lower levels after the summer.

EIA developed three oil price cases—Reference, High, and Low—to examine how alternative price paths could affect energy markets (Figure MT-4). The AEO2014 price cases included varying assumptions about: (1) investment and production decisions by the Organization of the Petroleum Exporting Countries (OPEC), (2) development of tight oil and bitumen resources in non-OPEC countries (including the United States), and (3) demand growth in China, the Middle East, and other countries outside the Organization for Economic Cooperation and Development (non-OECD countries).

Relative to the Reference case, the Low Oil Price case assumes lower economic growth and thus lower liquids demand from non-OECD regions; and rising production from OPEC countries, which displaces relatively more expensive crude oil from non-OPEC producers. In the Low Oil Price case, OPEC supplies 51% of the world's liquid fuels in 2040, compared with 44% in the Reference case. In the High Oil Price case, assuming stronger demand growth and fewer resources developed in OPEC countries, the non-OECD countries account for 62% of world liquids use in 2040, compared with 60% in the Reference case and 57% in the Low Oil Price case. The OPEC share of world liquids production never exceeds 40% in the High Oil Price case.

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

Figure MT-5. World petroleum and other liquids consumption by region in three cases, 2012 and 2040 (million barrels per day)



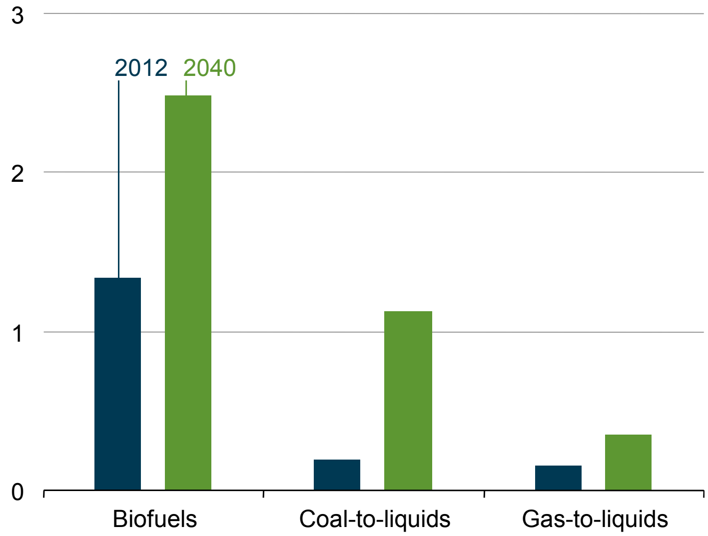
In the AEO2014 Reference, High Oil Price, and Low Oil Price cases, total world consumption of petroleum and other liquids in 2040 ranges from 117 to 121 million barrels per day (MMbbl/d) (Figure MT-5). The alternative oil price cases reflect shifts in both supply and demand. Although demand at the margin in the Organization for Economic Cooperation and Development (OECD) countries is influenced primarily by price, demand in non-OECD regions is driven primarily by rates of economic growth that are particularly uncertain. The AEO2014 High Oil Price case reflects a scenario in which strong economic growth in the emerging non-OECD nations increases the growth of their liquids demand and drives oil prices higher.

OECD petroleum and other liquids use grows in the Reference case to 47 MMbbl/d in 2040, while non-OECD use grows to 70 MMbbl/d. In the High Oil Price case, OECD petroleum and other liquids use in 2040 is lower than in the Reference case, at 45 MMbbl/d, but demand in the fast-growing non-OECD economies rises to 73 MMbbl/d. In the Low Oil Price case, OECD consumption grows to 51 MMbbl/d in 2040, and lower GDP growth in the non-OECD countries leads to slower growth in liquids demand, which reaches only 69 MMbbl/d in 2040. Non-OECD liquids demand would be even lower than projected in the Low Oil Price case, but low oil prices encourage more use of liquid fuels in the non-OECD nations in the long term.

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 production of nonpetroleum liquids more economically attractive.

World production of liquid fuels from biomass, coal, and natural gas increases

Figure MT-6. World production of nonpetroleum liquids by type in the Reference case, 2012 and 2040 (million barrels per day)



Nonpetroleum liquids are a small but increasing source of total liquids supply in the AEO2014 Reference case. World production of nonpetroleum liquids—including biofuels, coal-to-liquids (CTL), and gas-to-liquids (GTL)—totaled 1.7 MMbbl/d, or 1.9% of total world liquids production, in 2012. In 2040, nonpetroleum liquids production, at 4.0 MMbbl/d, accounts for 3.4% of total world liquids production (Figure MT-6).

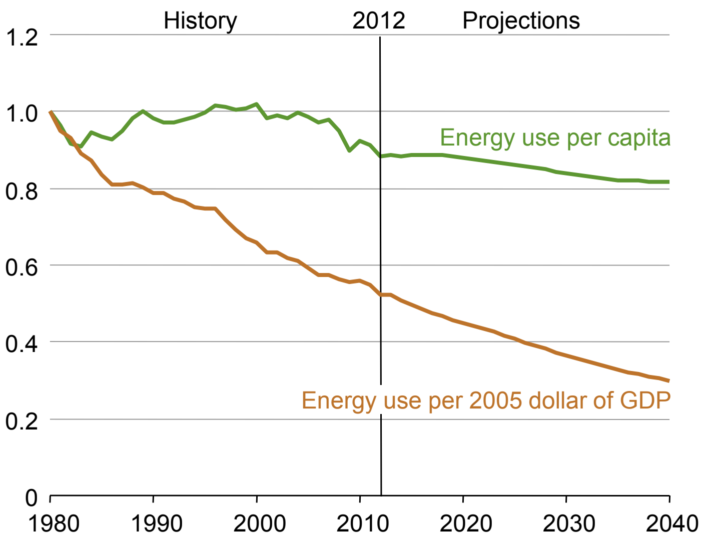
While world production of nonpetroleum liquids is spurred by sustained high prices, high prices alone are not expected to be sufficient to increase U.S. production of nonpetroleum liquids. As a result, no U.S. production of CTL or GTL is projected in the AEO2014 Reference case. U.S. biofuels production does grow in the projection, but only modestly, from 0.9 MMbbl/d in 2012 to 1.1 MMbbl/d in 2040.

The U.S. share of world biofuels production shrinks in the AEO2014 Reference case from 66% in 2012 to 43% in 2040. Biofuels development relies heavily on country-specific programs or mandates and outlooks for transportation fuels. U.S. demand for transportation fuels declines, and without significant additional market penetration of fuels with high-percentage ethanol blends or of drop-in fuels, the possibilities for expanded biofuel production are limited.

Biofuels production accounts for the largest share of total world nonpetroleum liquids production throughout the projection, although its share falls to 63% in 2040 from 79% in 2012. In 2040, world biofuels production of 2.5 MMbbl/d is 68% larger than world production of CTL and GTL combined.

In the United States, average energy use per person declines from 2012 to 2040

Figure MT-7. Energy use per capita and per dollar of gross domestic product in the Reference case, 1980-2040 (index, 1980 = 1)



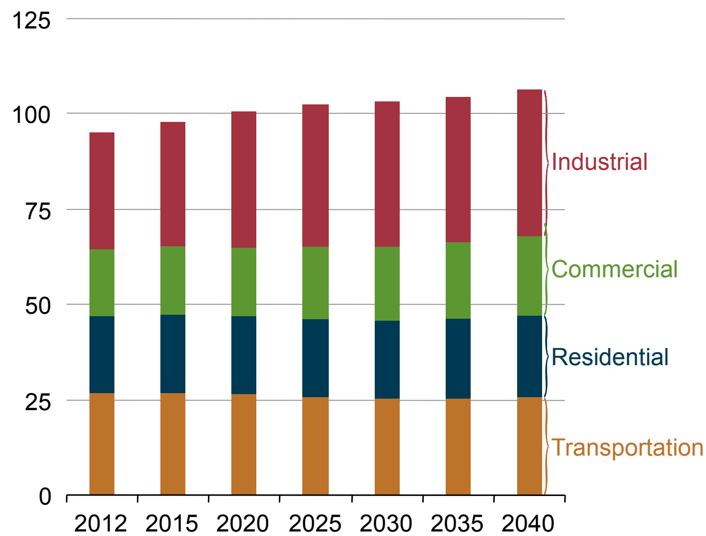
Population growth affects energy use through increases in housing, commercial floorspace, transportation, and economic activity. However, the structure and efficiency of the U.S. economy are changing in ways that can lower energy use. Changes in consumer behavior can also have an impact, such as changes in the rate of vehicle miles traveled (VMT) per licensed driver. U.S. population increases by 0.7%/year from 2012 to 2040; the economy, as measured by gross domestic product (GDP), increases at an average annual rate of 2.4%; and total energy consumption increases by 0.4%/year. As a result, energy intensity, measured both as energy use per person and as energy use per dollar of GDP, declines over the projection period (Figure MT-7).

The projected decline in energy use per capita is brought about largely by gains in appliance efficiency, a shift in production from cooler to warmer regions, and an increase in vehicle efficiency standards, combined with modest growth in travel per licensed driver. From 1970 through 2008, energy use dipped below 320 million British thermal units (Btu) per person for only a few years in the 1980s. In 2012, energy use per capita was about 302 million Btu. In the Reference case, energy use per capita declines to 279 million Btu per person in 2040—a level not seen since 1965.

Continual changes in the structure of the economy reduce energy use per dollar of GDP. Although the service industries' share of total shipments remains below the 2012 level of 78%, the manufacturing sector shifts about 1% of the output from energy-intensive industries to non-energy-intensive industries. 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 rising fuel prices, and stricter environmental regulations.

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

Figure MT-8. Primary energy use by end-use sector in selected years in the Reference case, 2012-40 (quadrillion Btu)



Total primary energy consumption, including fuels for electricity generation, grows by 0.4%/year in the Reference case, to 106.3 quadrillion Btu in 2040 (Figure MT-8). The largest increase, 7.8 quadrillion Btu, is in the industrial sector, with increased use of natural gas in some industries (bulk chemicals, for example) as a result of low natural gas prices coinciding with rising shipments in those industries. In the industrial sector, which was more severely affected than the other end-use sectors by the 2007-09 economic downturn, energy consumption increases by 7.0 quadrillion Btu from 2008 to 2040.

The second-largest increase in total primary energy use, 3.3 quadrillion Btu from 2012 to 2040, is in the commercial sector. Even as standards for building shells and energy efficiency are tightened and commercial energy intensity (energy use per square foot) decreases by 0.4%/year from 2012 through 2040, energy use grows by 0.6%/year as annual growth in commercial floorspace averages 1.0%.

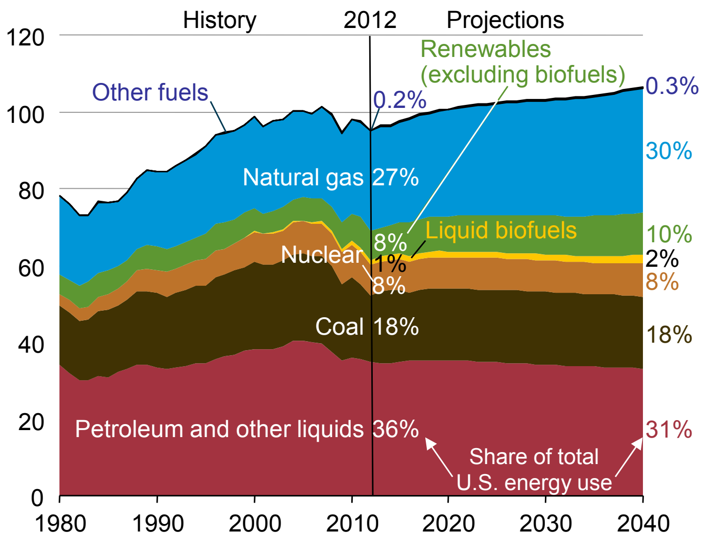
Primary energy use in the residential sector grows by 0.2%/year, or about 1.4 quadrillion Btu from 2012 to 2040. Energy use for space heating was down by almost 1 quadrillion Btu in 2012 because of an unusually warm heating season. In 2040, residential energy use is at 2011 levels, despite reduced energy use for space heating, lighting, and clothes washers, among other uses.

In the transportation sector, light-duty vehicle (LDV) energy use declines with the implementation of fuel economy standards. VMT remain flat (about 12,200 per licensed driver) in the near term, then begin to increase after 2025. From 2012 to 2040, total transportation sector energy use falls by more than 1 quadrillion Btu.

U.S. energy demand

Renewables and natural gas lead rise in primary energy consumption

Figure MT-9. Primary energy use by fuel in the Reference case, 1980-2040 (quadrillion Btu)



The fossil fuel share of total energy use declines from 82% in 2012 to 80% in 2040 in the Reference case, while renewable energy use grows (Figure MT-9). The renewable share of total energy use (including biofuels) increases from 9% in 2012 to 12% in 2040 in response to the availability of federal tax credits for renewable electricity generation and capacity during the early years of the projection and in response to state renewable portfolio standard (RPS) programs. Biofuel use mandated by the Renewable Fuels Standard (RFS) accounts for a small part of the increase.

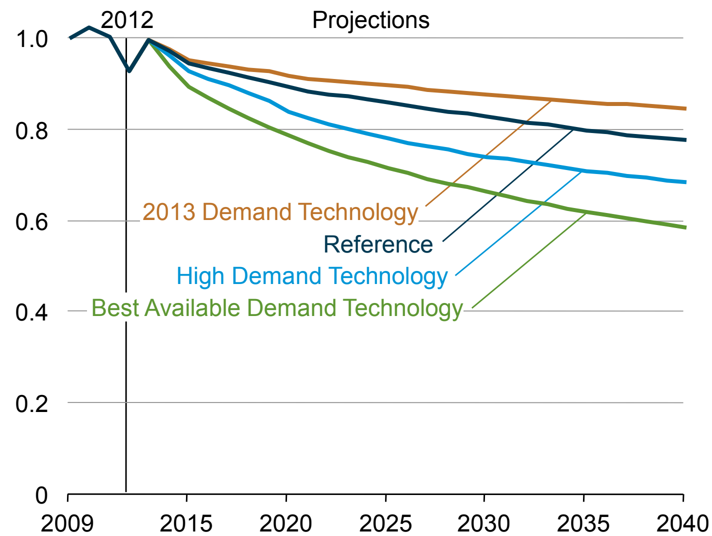
Natural gas consumption grows by about 0.8%/year from 2012 to 2040, led by increases in natural gas use for electricity generation and in the industrial sector. Growing production from tight shale keeps the price of natural gas to end users below 2005-08 levels through 2038.

Increases in vehicle fuel economy offset growth in transportation activity, resulting in a decline in the petroleum and other liquids share of fuel use while consumption of liquid biofuels increases. Biofuels, including E85, biodiesel blended into diesel, and ethanol blended into motor gasoline (up to 15%), account for 4% of all petroleum and other liquids consumption by energy content in 2040.

Coal consumption increases by an average of 0.3%/year from 2012 to 2040, remaining between the 2011 and 2012 levels through 2040. A small amount of coal-fired power plant capacity is added: a total of 2.2 gigawatts (GW) currently under construction and another 0.5 GW added after 2016 (including 0.3 GW with carbon sequestration capability). Coal-fired capacity retirements total 51 GW between 2012 and 2040, but the remaining coal-fired plants continue to be used extensively.

Residential energy intensity drops across a wide range of technology assumptions

Figure MT-10. Residential delivered energy intensity in four cases, 2009-40 (index, 2009 = 1)



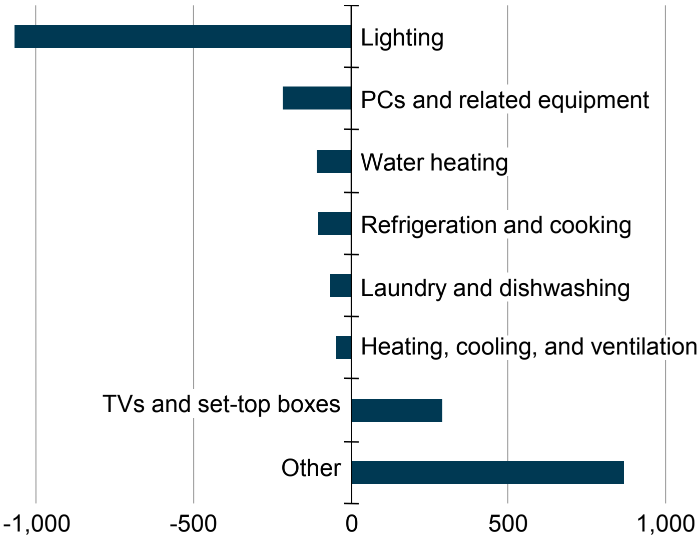
In the AEO2014 Reference case, the intensity of residential energy demand, defined as annual energy use per household, declines by 16% between 2012 and 2040 (Figure MT-10). Energy use for lighting, space heating, and water heating accounts for most of the decline. While household energy intensity decreases, total delivered energy consumption in the residential sector increases by about 5%, with the number of homes growing by 26% over the period. More use of distributed generation, such as from rooftop solar panels, would further reduce delivered energy intensity, but it is not projected to have a large effect, because electricity from distributed generation sources accounts for a small percentage of total electricity use in households over the projection period.

Three additional cases show the effects of different technology assumptions on residential energy intensity. The Best Available Demand Technology case limits purchases of new and replacement equipment by consumers to the most efficient models available at the time of purchase and assumes that the most energy-efficient specifications will be used in new home construction, which influences space heating and cooling demand. The High Demand Technology case assumes higher efficiency, earlier availability, lower cost, and more frequent energy-efficient purchases for some equipment than the Reference case. The 2013 Demand Technology case assumes no future improvement in efficiency for equipment or building shells beyond what is available in 2013.

From 2012 to 2040, household energy intensity declines by 37% in the Best Available Demand Technology case and by 26% in the High Demand Technology case. In the 2013 Demand Technology case, energy intensity is higher than in the Reference case but still declines by 9% from 2012 to 2040 as older, less-efficient appliances are replaced over time by 2013-vintage equipment.

Electricity use per household declines from 2012 to 2040 in the Reference case

Figure MT-11. Change in residential electricity consumption for selected end uses in the Reference case, 2012-40 (kilowatthours per household)



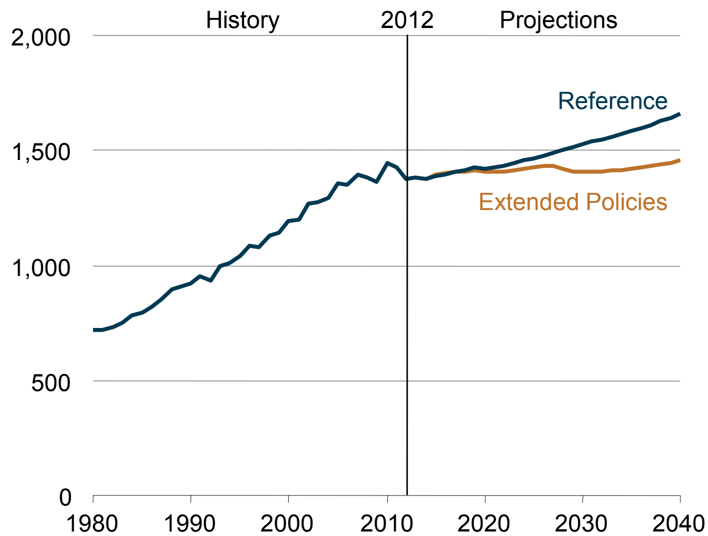
Annual electricity demand for the average household in the Reference case declines by 4%, from 12.1 megawatthours (MWh) in 2012 to 11.6 MWh in 2040. In 2012, the largest uses of electricity at the household level are space cooling, small devices and other minor electric end uses, and lighting. In 2040, electricity consumed for lighting per household is 65% lower, and electricity use for minor electric end uses and for space cooling rises by 33% and 17%, respectively (Figure MT-11). Regulations implementing lighting efficiency standards established by the Energy Independence and Security Act of 2007 (EISA2007) are a major factor in the replacement of incandescent bulbs with more efficient compact fluorescent lighting (CFL) and light-emitting diode (LED) lamps.

Although electricity consumption for most end uses declines on a per-household basis between 2012 and 2040, electricity consumption at the sectoral level increases for most end uses because of growth in the number of households. Most of the growth at the sectoral level comes from increasing market penetration of smaller electric devices, which have little coverage by efficiency standards, and by a growing need for cooling as the U.S. population shifts to warmer climates in the South.

From 2012 to 2040, residential electricity use grows by 21% as the fuel mix in the residential sector moves increasingly toward electricity. Petroleum and other liquids lose fuel share for every end-use service, and particularly for space heating, where both electricity and natural gas gain share. Natural gas loses fuel share in every end-use service except space heating, and it continues to account for more than half of the fuel consumed for space heating, water heating, and cooking through the projection. In 2040, overall natural gas use in the residential sector is 1% lower, and petroleum and other liquids use is 35% lower than in 2012.

Continuing efficiency gains restrain growth in residential electricity use

Figure MT-12. Residential electricity sales in two cases, 1980-2040 (billion kilowatthours)



In the AEO2014 Reference case, electricity is the only fuel for which demand increases in the residential sector from 2012 to 2040, in part as a result of population growth, regional population shifts, and temperature assumptions. Electricity is affected more than other fuels by the increased adoption of new and existing uses. In the Reference case, which includes only existing and announced standards and codes, residential electricity demand grows by 0.7%/year from 2012 to 2040 (Figure MT-12). In the Extended Policies case, which assumes additional rounds of appliance standards and building codes in the future, residential electricity use increases by 0.2%/year from 2012 to 2040. In contrast, residential electricity demand grew by an average of more than 2%/year over the previous 30 years.

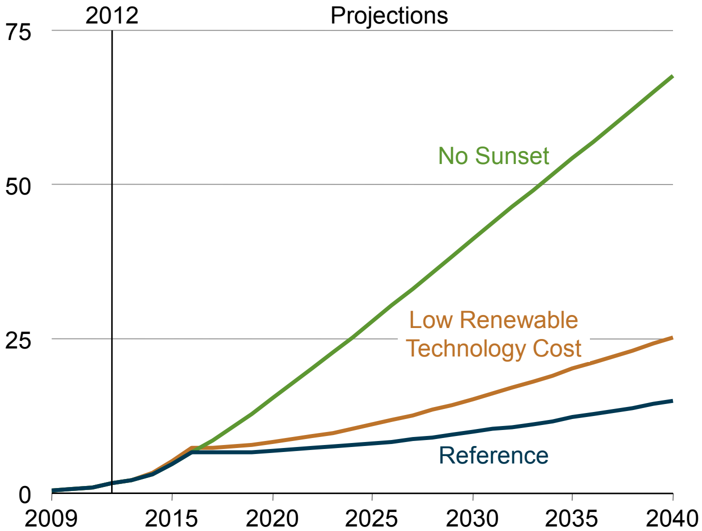
Most of the announced standards in the Reference case are scheduled to take effect in the near term. For instance, the Reference case includes changes in minimum efficiency levels for refrigerators and freezers in 2014 and for central air conditioners, air source heat pumps, and electric water heaters in 2015. The most distant standard assumed in the Reference case is the 2020 standard for general service lighting, which is a part of the second wave of congressionally-mandated standards from EISA2007.

Given the long lifetimes of most major residential equipment (10 to 30 years), it can take years for an appliance standard to affect the majority of installed equipment; but once the standard has been fully incorporated, electricity consumption tends to increase in line with the growth of housing stock (0.8%/year from 2012 to 2040)—as occurs around 2020 in the Reference case but not until 2035 in the Extended Policies case.

Residential energy demand

Extending tax credits supports increased residential use of renewable energy sources

Figure MT-13. Residential distributed generation capacity in three cases, 2009-40 (gigawatts)



Electricity generation capacity from residential solar photovoltaic (PV) and wind technologies roughly doubled from 2010 to 2012. In the AEO2014 Reference case, it doubles again in both 2014 and 2016 before slowing considerably as a result of the planned expiration of the investment tax credit (ITC) after 2016. Without the tax credit available, almost two decades pass before annual additions to residential distributed generation capacity surpass 0.5 gigawatts (GW), as they have in recent years.

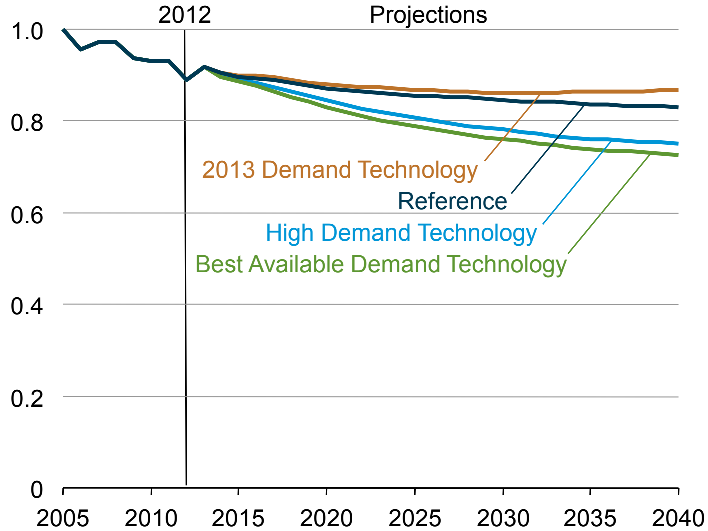
Two alternative cases present more optimistic scenarios for further growth in residential distributed generation, either by extending the tax credits or by lowering installed costs. With the ITC extended beyond its legislated 2016 expiration date in the No Sunset case, residential renewable capacity doubles twice from 2013 to 2019, again from 2019 to 2024, and again from 2024 to 2034. In 2040, more than 67 GW of solar and wind capacity is installed in the residential sector, as compared with less than 2 GW in 2012 (Figure MT-13).

The Low Renewable Technology Cost case includes the tax credit through 2016, as in the Reference case, but assumes lower installed costs than in the Reference case. Even in the Reference case, installed costs for renewable technologies decline from their present values. For example, solar PV installed costs fall from around $5,400 per kilowatt (kW) in 2012 to around $3,270 per kW in 2020 and around $2,900 per kW in 2040.

The Low Renewable Technology Cost case assumes an additional 20% reduction in installed costs after 2013, resulting in increased adoption of both solar PV and wind technologies for electricity generation, especially in locations with the combination of high electricity prices and sufficient renewable resources. By 2040, more than 25 GW of renewable capacity is installed, 10 GW more than in the Reference case.

Commercial sector energy intensity varies with technology improvements

Figure MT-14. Commercial delivered energy intensity in four cases, 2005-40 (index of energy use per square foot, 2005 = 1)



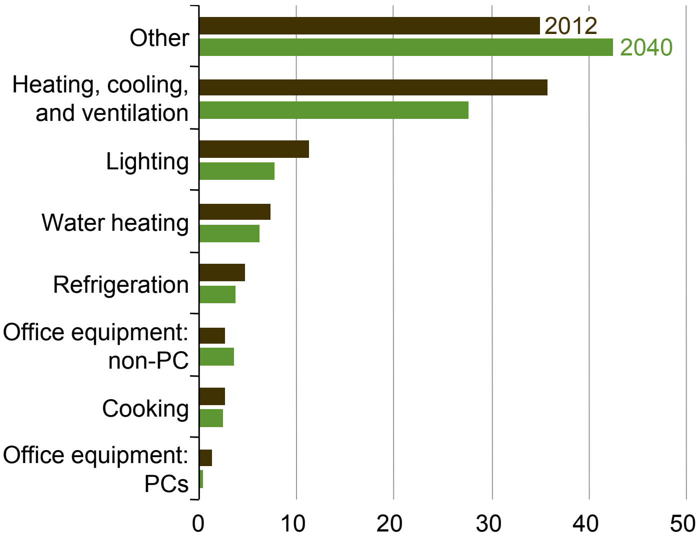
In the AEO2014 Reference case, commercial sector energy intensity, or delivered energy consumption per square foot of commercial floorspace, declines by an average of 0.3%/year from 2012 to 2040 (Figure MT-14). During this period, delivered electricity consumption grows by 0.7%/year despite 1.0% annual growth in commercial floorspace. Natural gas consumption also increases over the period despite increases in building shells and equipment efficiency.

Improvements in major end-use equipment and distributed generation technologies help to slow the growth of delivered energy consumption in the commercial sector. Varying the rate of improvement in the 2013 Demand Technology, High Demand Technology, and Best Available Demand Technology cases shows a range in which equipment and building shell efficiency improvement, or lack thereof, could affect commercial energy consumption.

In the 2013 Demand Technology case, which restricts equipment and shell efficiencies to those available in 2013, energy intensity is reduced by 2.7% from 2012 to 2040, averaging 0.1%/year as equipment is replaced over time and as new buildings are constructed. In the High Demand Technology case, which assumes lower costs and higher efficiencies for commercial equipment and building shells and a 7% real discount rate, commercial energy intensity falls by 0.6%/year, or twice the rate in the Reference case. As a result, energy intensity is 15.8% lower in 2040 than in 2012. The Best Available Demand Technology case allows for even greater shell efficiency improvements than the High Demand Technology case, and also limits future technology choices to only the most efficient models of equipment in each year. As a result, commercial sector energy intensity declines by 0.7%/year on average, to 18.5% below the 2012 level in 2040.

Energy use continues to shift from personal computing equipment to networked computing

Figure MT-15. Energy intensity of selected commercial end uses in the Reference case, 2012 and 2040 (thousand Btu per square foot)



Commercial energy intensity—the ratio of energy consumption to floorspace—decreases from 2012 to 2040 for most electric end uses in the Reference case, while commercial floorspace increases by 1.0% annually (Figure MT-15). Electricity accounted for 54.5% of commercial delivered energy use in 2012.

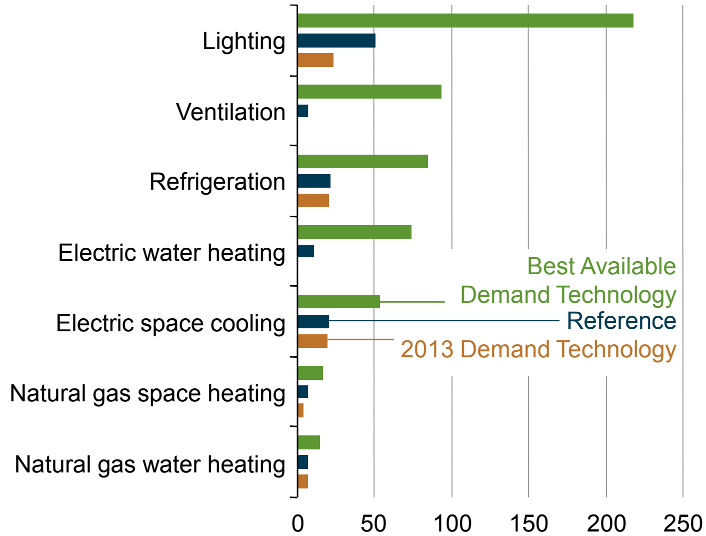
Electricity use for personal computers (PCs), including desktop and laptop computers and monitors, continues to decline. Reductions in processor power use, improvements in display backlighting, and a general shift from desktop to mobile computing devices all cause the energy consumption of PC office equipment to fall by 5.6% annually. With expanding use of web-based services increasing the role of servers in data centers, electricity use by non-PC office equipment grows by 2.0%/year in the Reference case.

Federal efficiency standards moderate energy consumption by major end-use equipment, such as space heating and cooling, water heating, lighting, and refrigeration. The Energy Independence and Security Act of 2007 (EISA2007) mandatory efficacy improvements for lighting continue to foster the adoption of advanced incandescent, fluorescent, and solid-state lighting technologies. As a result, the share of purchased electricity consumption used for lighting declines from 20.7% in 2012 to 14.7% in 2040.

The growing use of energy for miscellaneous electric loads, many of which are not currently subject to federal standards, leads to a 21.4% increase in energy intensity from 2012 to 2040 for other end uses in the Reference case. Miscellaneous electric loads in the commercial sector include medical equipment, video displays, and many other devices. Increases in the use of such devices and equipment can vary greatly by building type and service demand.

Efficiency gains for advanced technologies reduce commercial energy consumption growth

Figure MT-16. Efficiency gains for selected commercial equipment in three cases, 2040 (percent change from 2012 installed stock efficiency)



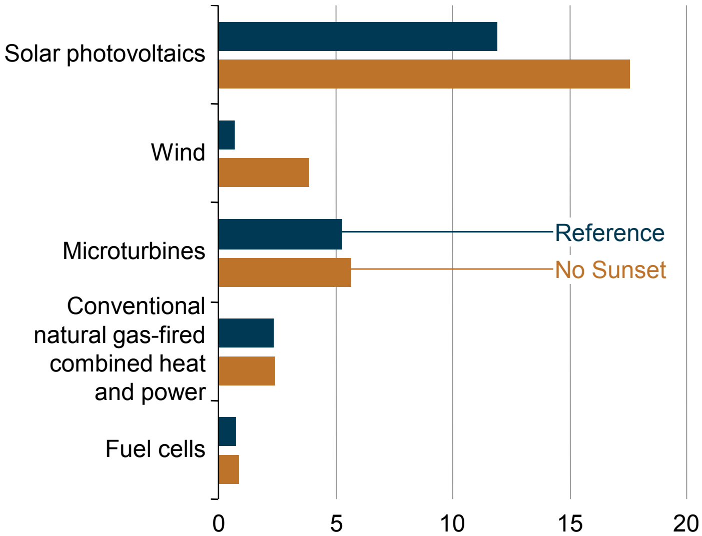
Behind the 0.3% average annual decline in delivered energy intensity in the commercial sector in the AEO2014 Reference case is a shift in the mix of end-use services, from core building services (space heating, space cooling, ventilation, water heating, lighting, cooking, and refrigeration) to other office equipment and electric services. Core end-use energy intensity falls by 0.9%/year from 2012 to 2040, and the intensity of other end uses increases by 0.6%/year on average.

The largest energy efficiency improvements in the Reference case are for lighting, as a result of new standards and the penetration of LED technologies. PC office equipment is a close second to lighting, as a result of the shift toward network computing. Refrigeration, electric space cooling, and electric water heating also show significant efficiency gains (Figure MT-16).

The Best Available Demand Technology case demonstrates significant potential for further improvements—especially for electric equipment in the core end uses. In this case, core end-use intensity declines at more than twice the rate of the Reference case, and core delivered energy use in 2040 is 1.3 quadrillion Btu lower than in the Reference case. Lighting accounts for 35% of the additional delivered energy savings, resulting from both earlier and more widespread penetration of LED technologies than in the Reference case. Beyond lighting, the Best Available Technology case projects significant savings for variable air volume ventilation systems, high-efficiency chiller systems for space cooling, high-efficiency natural gas furnaces, and various advanced refrigeration technologies. Together with lighting, those end uses account for more than 90% of the energy savings relative to the Reference case, with delivered energy consumption in 2040 only 0.6 quadrillion Btu higher than in 2012 and delivered energy intensity declining by 0.7%/year.

Renewable technologies drive more additions to distributed generation capacity

Figure MT-17. Additions to electricity generation capacity in the commercial sector in two cases, 2012-40 (gigawatts)



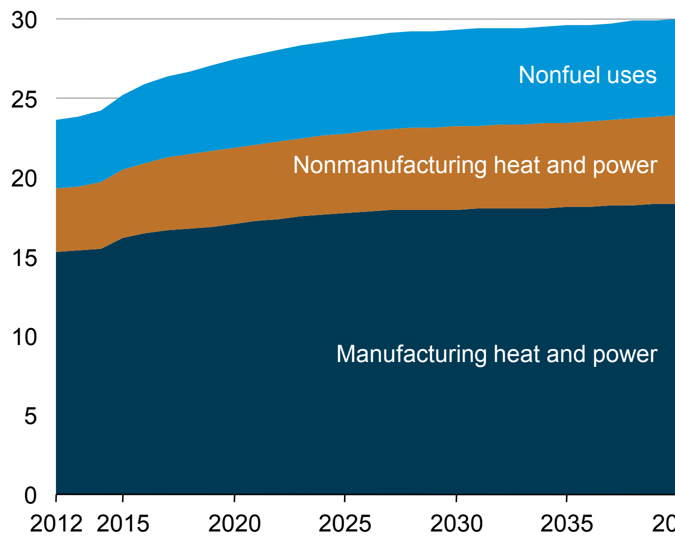
Renewable energy sources, chiefly solar photovoltaic and wind, continue to dominate new commercial distributed generation capacity in the AEO2014 Reference case, accounting for 62.3% of commercial capacity in 2040. Lower prices for photovoltaic inverters and panels, decreasing installation costs, federal investment tax credits, and state and utility rebates all contribute to growth in commercial photovoltaic capacity, which increases by 5.7%/year from 2012 to 2040 in the Reference case. The current 30% federal investment tax credit continues through 2016, after which it reverts to 10%. In the No Sunset case, with investment tax credits for all distributed generation technologies extended through 2040, photovoltaic capacity increases by an average of 7.0%/year.

Small-scale wind capacity grows by 14.2%/year from 2012 to 2040 in the No Sunset case, compared with 7.9%/year in the Reference case (Figure MT-17). As in the case of solar photovoltaic, additional federal and local incentives help to support the growth in commercial wind capacity. Commercial wind capacity accounts for 11.1% of the 35.7 gigawatts (GW) of total distributed generation capacity in 2040 in the No Sunset case, with photovoltaic capacity accounting for 58.1%.

Rising fuel prices offset the effects of the 10% investment tax credit on nonrenewable technologies for distributed generation. In the Reference case, microturbine capacity using natural gas grows by 15.3%/year on average, from 98.3 MW in 2012 to 5.4 GW in 2040, and its growth rate in the No Sunset case is only slightly higher, at 15.7%/year. The microturbine share of total distributed generation capacity in 2040 is 16.2% in the No Sunset case, compared with 20.4% in the Reference case. Fuel cell capacity grows by an average of 12.3%/year in the Reference case and 12.7%/year in the No Sunset case.

Growth in industrial energy consumption is slower than growth in shipments

Figure MT-18. Industrial energy consumption by application in the Reference case, 2012-40 (quadrillion Btu)



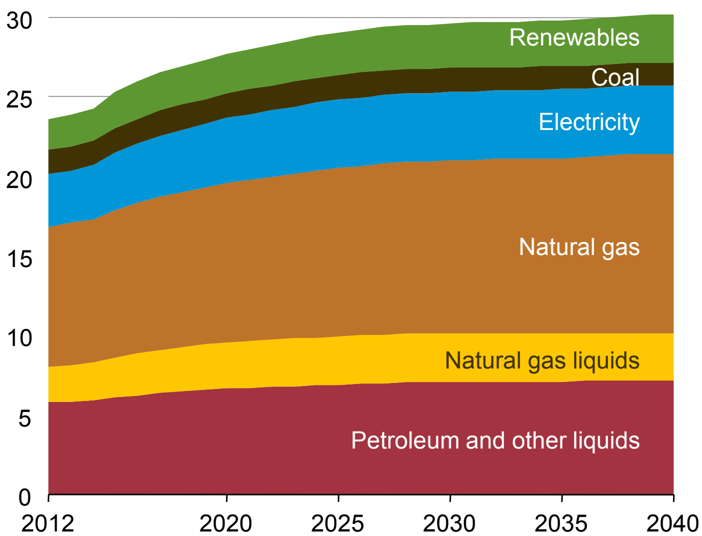
In the AEO2014 Reference case, manufacturing shipments increase by 87% from 2012 to 2040, while delivered energy consumption for heat and power in the manufacturing sector increases by only 19%. The continued decline in energy intensity of manufacturing is explained in part by continued improvement in the efficiency of industrial equipment as energy prices gradually increase, and by a shift in the share of shipments from energy-intensive manufacturing industries to non-energy-intensive industries. With growing foreign competition, shipments and energy use in many trade-exposed energy-intensive industries (bulk chemicals, petroleum refineries, iron and steel, and aluminum) begin declining around 2025. For less energy-intensive manufacturing industries (plastics, computers, machinery, and transportation), shipments continue to grow, capturing a larger share of total U.S. manufacturing output.

In the nonmanufacturing industries (agriculture, mining, and construction), energy intensity declines from 2012 to 2040, as shipments increase by 57% and as total delivered energy consumption increases by 41%. The decline in energy intensity is limited by the mining industry, where energy intensity increases as resource extraction moves into less productive areas.

U.S. manufacturing energy consumption for heat and power grows in the Reference case by an average of 1.1%/year from 2012 to 2025, and then slows to 0.2%/year from 2025 to 2040 (Figure MT-18). Nonmanufacturing energy consumption grows by an average of 1.9%/year from 2012 to 2025, and then slows to 0.6%/year from 2025 to 2040. Nonfuel energy use, principally bulk chemical feedstocks and asphalt, grows robustly at 2.6% annually from 2012 to 2025, largely as a result of rising bulk chemical shipments. After 2025, nonfuel energy use increases 0.1%/year, in parallel with bulk chemical shipments.

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

Figure MT-19. Industrial energy consumption by fuel in the Reference case, 2012-40 (quadrillion Btu)



Total delivered energy consumption in the industrial sector increases by 28% (6.6 quadrillion British thermal units [Btu]) from 2012 to 2040 in the AEO2014 Reference case (Figure MT-19). Much of the growth is in natural gas use, which accounts for 34% of the total increase in energy consumption from 2012 to 2025 and 59% of the increase from 2025 to 2040, as a result of relatively low natural gas prices from steady increases in domestic natural gas production through 2040. The mix of industrial energy sources stays relatively constant, however, reflecting limited remaining capability for switching from other fuels to natural gas in most industries.

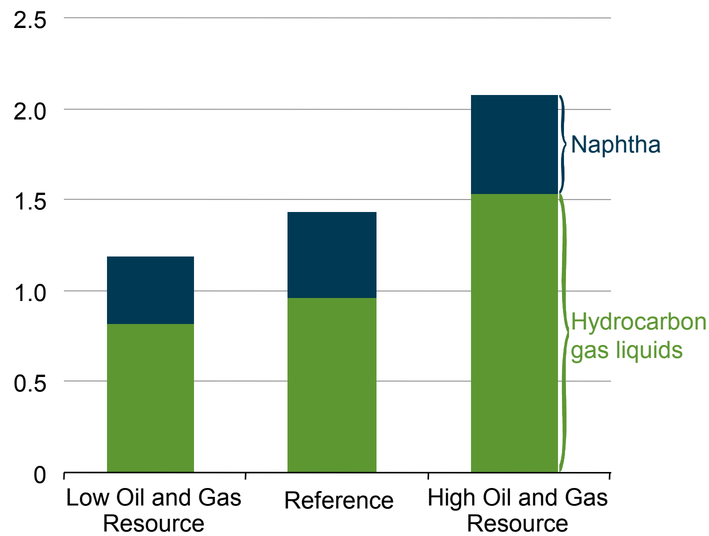
Renewable fuel consumption increases by 53% from 2012 to 2040, although as a percentage of total energy consumption, renewable fuels remain small, at 10% of total energy consumption in 2040. The paper industry remains the predominant user of renewable energy, accounting for roughly 66% of the energy consumed for heat and power in that industry.

Industrial consumption of hydrocarbon gas liquids (HGL) increases by 35% from 2012 to 2025, followed by a 5% decline from 2025 to 2040. HGL are consumed predominantly as feedstocks in the bulk chemicals industry, and smaller amounts (mostly propane) are consumed for process heat in other industries. Coal is the only industrial fuel that shows a consistent decline in consumption, from 6% of the total in 2012 to 5% in 2040.

Low natural gas prices and increased availability of biomass contribute to growth in the use of combined heat and power (CHP). Industrial CHP generation, excluding the refining industry, increases by 88%, from 111.3 billion kilowatthours (kWh) in 2012 to 208.9 billion kWh in 2040.

Bulk chemicals feedstock mix reflects both relative fuel prices and demand for chemicals

Figure MT-20. Change in liquid feedstock consumption in three cases, 2012-40 (quadrillion Btu)



Liquid feedstock consumption in the bulk chemicals industries is divided between heavy feedstock (petroleum-based naphtha and gasoil) and light feedstock (hydrocarbon gas liquids [HGL], primarily ethane and propane), according to their relative prices. Heavy feedstock prices follow the price of oil, and prices for HGL feedstock, a composite of propane and ethane prices, vary relative to both oil and natural gas prices. Ethane prices are also influenced by production of ethane from natural gas plant liquids and by demand for organic and resin chemicals.

Shipments in the bulk chemicals industries grow by 60% from 2012 to 2028 in the AEO2014 Reference case, followed by no growth after 2028. Growth in total liquid feedstock consumption follows a similar pattern.

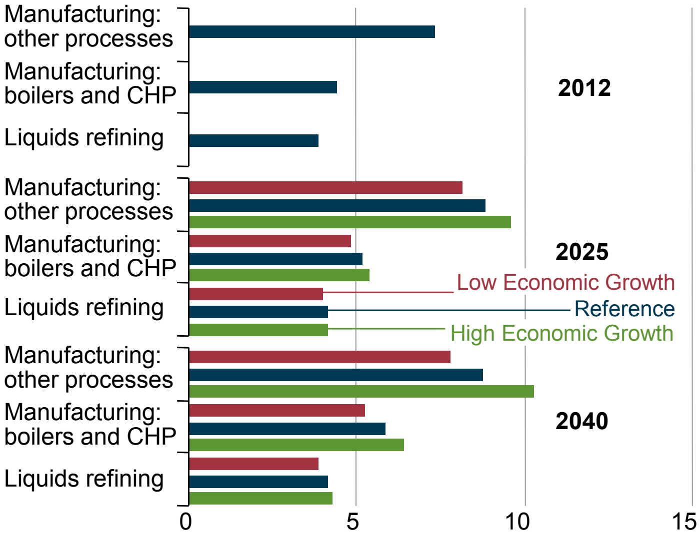
In the AEO2014 projections, the mix of feedstocks used to produce bulk chemicals varies with changes in supply assumptions. In the High Oil and Gas Resource case, natural gas prices in 2040 are 40% lower than in the Reference case, while crude oil prices are 12% lower. As a result, the HGL feedstock price in 2040 is 31% lower than in the Reference case, while the heavy feedstock price is only 18% lower. In the Low Oil and Gas Resource case, the HGL feedstock price in 2040 is 13% higher than in the Reference case, while the heavy feedstock price is only 3% higher.

The greater variation in feedstock prices in the High Oil and Gas Resource case leads to more change in the feedstock mix (Figure MT-20), with the use of light HGL feedstock growing faster than the use of heavy naphtha feedstock. In all the cases, consumption of heavy feedstock continues to grow from 2012 to 2040, because some chemicals, such as butadiene and aromatics, cannot be made in sufficient quantities to meet demand by cracking only HGL feedstocks.

Industrial sector energy demand

For manufacturing applications, heat and power use varies with economic assumptions

Figure MT-21. Heat and power consumption for refining and manufacturing applications in three cases, 2012, 2025, and 2040 (quadrillion Btu)



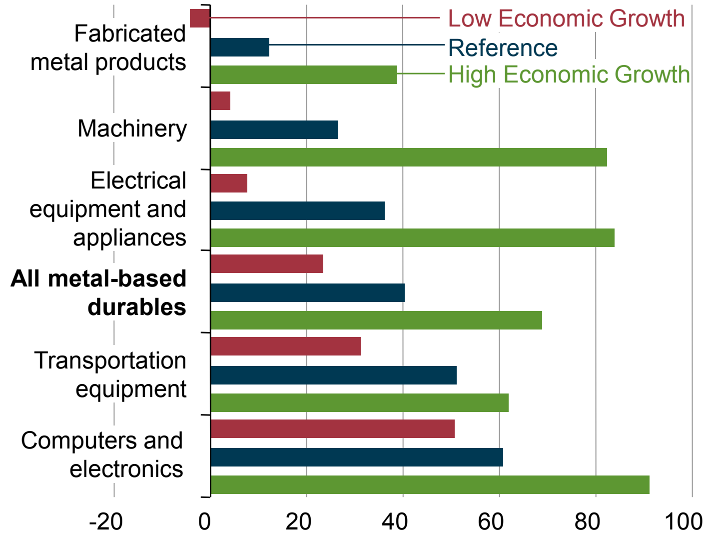
There are three principal uses of energy for heat and power in manufacturing: steam generation for process heat applications, direct-fired heat applications, and the use of electricity to drive machinery. Steam, produced in boilers and by CHP applications, accounted for 4.4 quadrillion Btu of the 14.8 quadrillion Btu of energy consumed for heat and power in the manufacturing sector in 2012. The remaining 10.4 quadrillion Btu of energy consumed for heat and power in manufacturing in 2012, consisting of fuels and purchased electricity, was used in applications such as motors, kilns, direct process heaters, and refining of liquid fuels. Energy for manufacturing can also be used to produce chemical feedstocks.

Demand for heat in the manufacturing sector is particularly sensitive to the rate of economic growth (Figure MT-21). In the Reference case, industrial energy use for boilers and CHP grows by 32% from 2012 to 2040, compared with 45% in the High Economic Growth case and 18% in the Low Economic Growth case.

The energy-intensive manufacturing industries account for a disproportionate amount of the energy used in boiler and CHP applications. The paper industry is the largest industrial user of boiler and CHP, which accounted for 1.6 quadrillion Btu, or roughly 80%, of total heat and power consumption in the paper industry in 2012. The paper industry also recovered 1.2 quadrillion Btu of renewable and waste fuels in 2012, specifically wood, pulping liquor, and municipal solid waste, all of which was consumed in recovery boilers. In addition, roughly half of the energy consumed for heat and power in the bulk chemicals industry in 2012 was used for boiler and CHP applications. Adoption of CHP in energy-intensive industries with stable base-steam demand offers significant potential for energy savings and cost reductions.

Energy consumption in the metal-based durables industries increases rapidly

Figure MT-22. Cumulative growth in energy consumption by metal-based durables industries in three cases, 2012-40 (percent)



Energy consumption in the metal-based durables industries increases at a rate that is more than twice the rate of growth in the energy-intensive industries, driven by higher growth in shipments relative to the energy-intensive industries. Energy consumption in the metal-based durables industries grows from 1.4 quadrillion Btu in 2012 to 2.0 quadrillion Btu in 2040 in the AEO2014 Reference case, compared with 1.7 quadrillion Btu in 2040 in the Low Economic Growth case and 2.4 quadrillion Btu in 2040 in the High Economic Growth case.

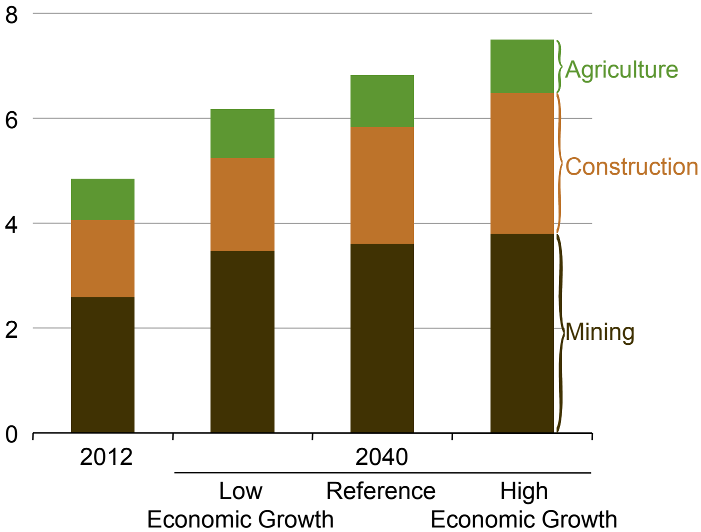
In each of the three cases, the energy intensity of metal-based durables industries declines from 2012 to 2040. Shipments grow more rapidly than energy use, as the industries' energy efficiency improves significantly over the period. Energy intensity in the metal-based durables industries declines by 1.5%/year from 2012 to 2040 in both the Reference and Low Economic Growth cases and by 1.7%/year in the High Economic Growth case.

The mix of energy used in the metal-based durables industries differs significantly from that in the energy-intensive industries. With extensive use of machine drive, the metal-based durables industries use more electricity as a share of total energy consumption. Also, manufacturing in the metal-based durables industries uses energy for facility support activities, such as lighting and climate control.

Growth varies among specific segments of the metal-based durables industries (Figure MT-22). After 2025, shipments and energy use slow significantly in the fabricated metals and machinery segments but only slightly in other segments of the metal-based durables industries. The segment with the fastest growth in shipments and energy use is computers and electronic products.

Nonmanufacturing energy intensity reductions are tempered by the mining industry

Figure MT-23. Delivered energy consumption by nonmanufacturing industries in three cases, 2012 and 2040 (quadrillion Btu)



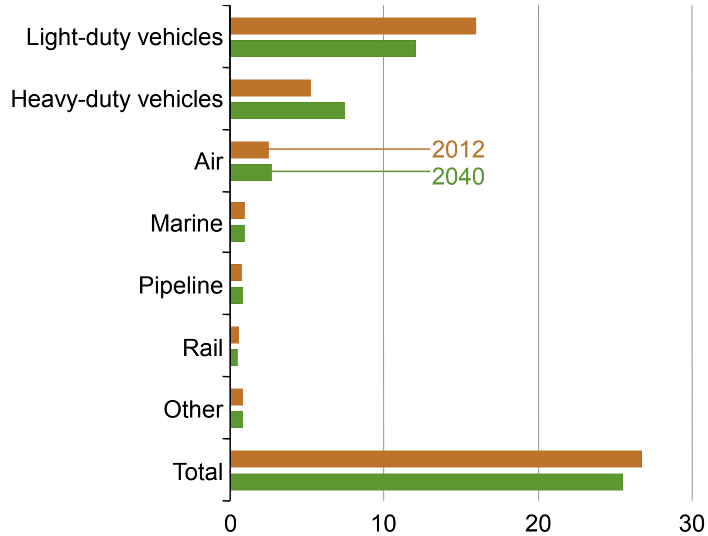
In 2040, nonmanufacturing industries account for $2.6 trillion (2005 dollars) in shipments in the AEO2014 Reference case—a 57% increase from 2012. From 2012 to 2040, total energy consumption in the nonmanufacturing subsector increases by 27% (1.3 quadrillion Btu) in the Low Economic Growth case, 41% (2.0 quadrillion Btu) in the Reference case, and 55% (2.6 quadrillion Btu) in the High Economic Growth case (Figure MT-23).

The nonmanufacturing subsector consists of the construction, agriculture, and mining industries. In the Reference case, it accounts for roughly 23% of total value of shipments and about 23% of total delivered energy consumed in the industrial sector in 2040. The mining industry is the most energy-intensive of the three industries, accounting for 53% of the energy consumed in the nonmanufacturing subsector in 2040 but only 20% of the value of shipments. In contrast, the construction industry accounts for 65% of the shipments in 2040 but only 33% of the energy consumed, and the agriculture sector accounts for 15% of the shipments and 14% of the energy consumed.

Overall, energy intensity declines in the nonmanufacturing subsector by 10% from 2012 to 2040 in the Reference case. Construction and agriculture both show a decline in energy intensity of 17% from 2012 to 2040, whereas the mining industry shows an increase in energy intensity of 26% over the same period. The energy intensity of mining increases as producers move into less-productive areas over time.

Transportation sector energy consumption declines in the Reference case

Figure MT-24. Delivered energy consumption for transportation by mode in the Reference case, 2012 and 2040 (quadrillion Btu)



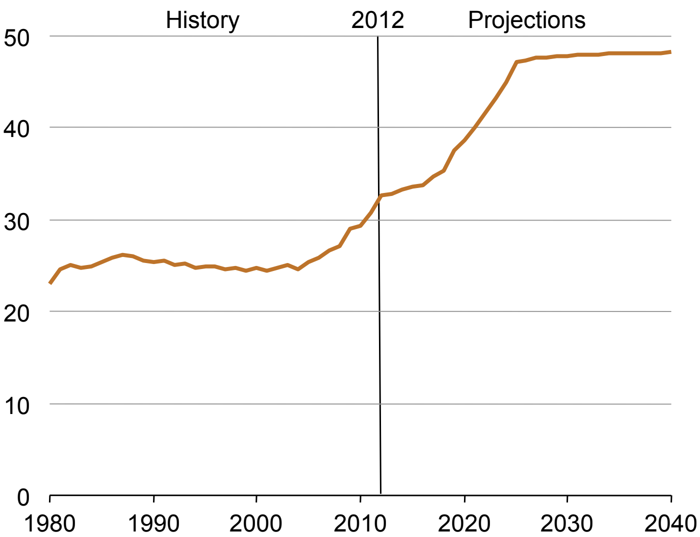
Transportation sector energy consumption declines from 26.7 quadrillion Btu in 2012 to 25.5 quadrillion Btu in 2040 in the AEO2014 Reference case (Figure MT-24), differing markedly from the longer historic trend. Transportation energy consumption grew by an average of 1.3%/year from 1973 to 2007, when it totaled 29.1 quadrillion Btu [*3*]. The decline in transportation energy demand is the result of significantly less energy use by light-duty vehicles (LDVs), along with a small decline in energy use by rail, which together more than offset increased energy use by heavy-duty vehicles (HDVs), aircraft, marine vessels, and pipelines.

LDV energy demand falls sharply, from 16.0 quadrillion Btu in 2012 to 12.1 quadrillion Btu in 2040, as the result of higher fuel economy that more than offsets increases in LDV travel. Even with new standards for HDV fuel efficiency and greenhouse gas emissions starting in 2014, energy use by HDVs (including tractor trailers, buses, vocational vehicles, and heavy-duty pickup trucks and vans) increases the fastest among the transportation modes, from 5.3 quadrillion Btu in 2012 to 7.5 quadrillion Btu in 2040, as a result of increased demand for travel as economic output grows.

Aircraft energy consumption increases modestly, from 2.5 quadrillion Btu in 2012 to 2.7 quadrillion Btu in 2040, with growth in personal air travel mostly offset by gains in aircraft fuel efficiency. Energy consumption by marine vessels grows as increased international trade boosts demand for shipping and rising incomes increase demand for recreational boating. Pipeline energy use is tempered as increasing volumes of natural gas are produced closer to end-use markets, and energy consumption for rail travel declines slightly as the efficiency of rail improves more rapidly than travel demand increases.

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

Figure MT-25. Average fuel economy of new light-duty vehicles in the Reference case, 1980-2040 (miles per gallon)

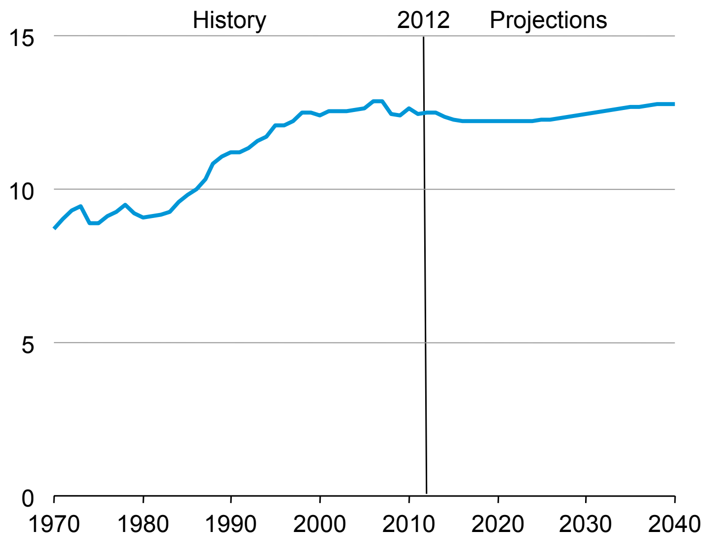


The 1978 introduction of corporate average fuel economy (CAFE) standards for LDVs increased the average fuel economy of these vehicles from 19.9 miles per gallon (mpg) in 1978 to 26.2 mpg in 1987. Despite technology improvements, however, as sales of light trucks increased from 17% of new LDV sales in 1980 to 53% in 2004 [*4*], fuel economy fell below 26 mpg in 1989 and did not rise above that level until 2007. From 2008 through 2012, LDV average fuel economy rose steadily from 27.1 mpg to 32.7 mpg, as a result of more stringent CAFE standards for light-duty trucks starting in model year 2008 and for passenger cars starting in model year 2011; CAFE and greenhouse gas (GHG) emissions standards for passenger cars and light-duty trucks starting in model year 2012; rising fuel prices; and a reduction in the sales share of light trucks.

The National Highway Traffic Safety Administration (NHTSA) and the U.S. Environmental Protection Agency (EPA) have jointly issued new GHG emissions and CAFE standards for model years 2012 through 2025 [*5*, *6*], which are included in AEO2014. As a result, the fuel economy of new LDVs, measured in terms of their compliance values in CAFE testing [*7*], rises from 32.7 mpg in 2012 to 47.2 mpg in 2025 (Figure MT-25). The GHG emissions and CAFE standards are held roughly constant after 2025 in the Reference case, but fuel economy continues to rise, to 48.2 mpg in 2040, as new fuel-saving technologies are adopted. In 2040, passenger car fuel economy averages 55.6 mpg, and light-duty truck fuel economy averages 40.9 mpg.

Miles traveled per licensed driver remains below its historic high through 2040

Figure MT-26. Vehicle miles traveled per licensed driver in the Reference case, 1970-2040 (thousand miles)



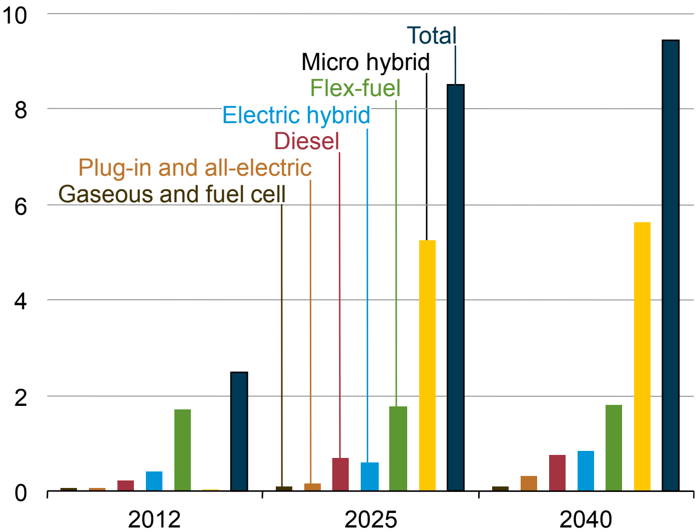
Personal vehicle travel demand, measured as annual vehicle miles traveled (VMT) per licensed driver, declined from its historic high of 12,900 miles in 2007 to about 12,500 miles in 2012. In the AEO2014 Reference case, personal vehicle travel continues declining to 12,200 miles in 2020 before increasing to 12,800 miles in 2040—still below the 2007 level (Figure MT-26). Although motor gasoline prices, personal income, and vehicle fuel efficiency continue to influence personal vehicle travel, the major factors in the decline from 2013 through 2025 are changes in travel patterns by driver age and gender groups and changes in employment rates.

The number of licensed drivers grows by an average of 0.8%/year from 2012 to 2040, but declines in personal vehicle travel demand for some age groups cause an overall decline in VMT per licensed driver. The employment rate of the licensed driver population (the employed, nonfarm population ages 16 and over), which fell by 4 percentage points during the 2007-09 recession, does not rebound to pre-recession levels before 2040, tempering the projected growth in personal travel. Total light-duty VMT increase in the Reference case to 3.4 trillion in 2040—a 29% increase from 2012—as a result of 26% overall growth in the number of licensed drivers, from 213 million in 2012 to 269 million in 2040.

Although vehicle sales also grow through 2040, the number of vehicles per licensed driver drops from 1.12 in 2007 to 1.02 in 2040, limiting the availability of vehicles for travel. Motor gasoline prices fall from 2012 levels and do not exceed that level until 2035, while real personal disposable income per licensed driver increases by 55% through 2040. The changes in travel behavior and demographics more than offset the boost to personal travel provided by income growth and lower motor gasoline prices.

Sales of vehicles using nongasoline technologies grow by nearly 400 percent from 2012 to 2040

Figure MT-27. Sales of light-duty vehicles using nongasoline technologies by type in the Reference case, 2012, 2025, and 2040 (million vehicles sold)



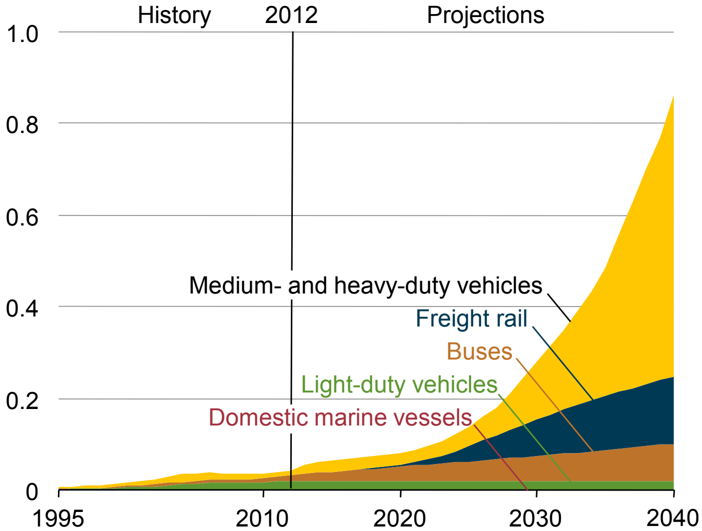
Light-duty vehicles (LDVs) that use diesel, alternative-fuel, hybrid-electric, or all-electric systems play a significant role in meeting more stringent GHG emissions and corporate average fuel economy (CAFE) standards in the AEO2014 Reference case, with sales increasing from 18% of all new LDV sales in 2012 to 55% in 2040. Micro hybrid vehicles, defined here as conventional gasoline vehicles with micro hybrid systems that manage engine operation at idle, represent 33% of new LDV sales in 2040 (Figure MT-27). Flex-fuel vehicles (FFVs), which can use blends of up to 85% ethanol, represent about 11% of all new LDV sales in 2040. Current incentives for manufacturers selling FFVs, which are available in the form of fuel economy credits earned for CAFE compliance, expire at the end of 2019. As a result, the FFV share of LDV sales rises through 2019 and then remains flat through the rest of the projection.

Sales of hybrid electric and all-electric vehicles that use stored electric energy for motive power grow substantially in the Reference case. Gasoline- and diesel-electric hybrid vehicles account for 5% of total LDV sales in 2040. Plug-in hybrid and all-electric vehicles account for 2% of total LDV sales and 3% of total sales of vehicles using diesel, alternative-fuel, hybrid, or all-electric systems.

The diesel vehicle share of total LDV sales remains roughly constant from 2012 to 2040 in the Reference case. Light-duty gaseous and fuel cell vehicles account for less than 1% of new vehicle sales because of limited fueling infrastructure and the high incremental costs of the vehicles.

Natural gas use for transportation fuel grows but still makes up a modest share of total use

Figure MT-28. Natural gas consumption in the transportation sector in the Reference case, 1995-2040 (quadrillion Btu)



The use of compressed natural gas (CNG) and liquefied natural gas (LNG) in LDVs, HDVs, locomotives, buses, and marine vessels grows from 43 trillion Btu in 2012 to 863 trillion Btu in 2040 in the Reference case (Figure MT-28). Still, CNG and LNG account for only 3% of total energy consumption in the transportation sector in 2040, similar to the amount of natural gas consumed in pipeline transport.

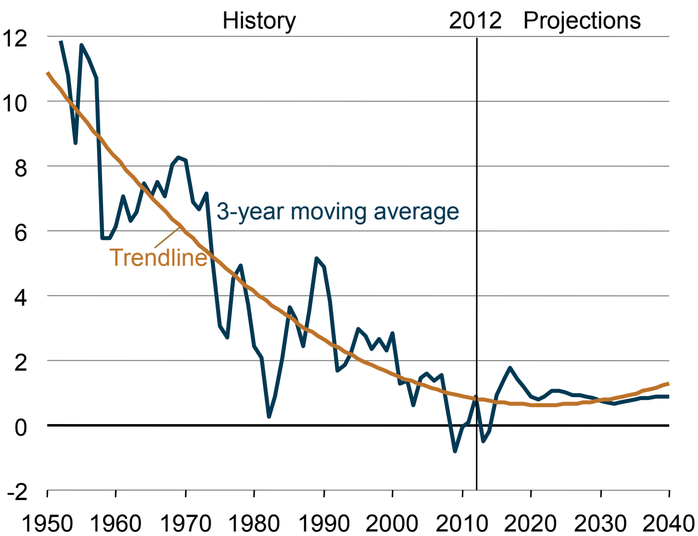
Medium-duty and heavy-duty vehicles—including tractor trailers, vocational vehicles, pickups, and vans with a gross vehicle weight rating (GVWR) of 10,001 pounds or more—become the largest consumers of CNG and LNG, increasing from 11 trillion Btu in 2012 to 613 trillion Btu in 2040 in the Reference case. The increase is spurred by relatively low natural gas prices. Initially, natural gas is consumed primarily by medium-duty trucks using CNG; but the vast majority of growth in natural gas consumption is for heavy-duty trucks (primarily tractor trailers) using LNG—a relatively high-mileage application in which the fuel cost savings of LNG offset the significant incremental capital cost of LNG vehicles.

LNG energy consumption by freight rail locomotives grows to 148 trillion Btu by 2040, when it accounts for 35% of total freight rail energy consumption, with fuel cost savings offsetting the incremental capital costs of LNG locomotives. CNG and LNG energy demand for buses grows from 13 trillion Btu in 2012 to 81 trillion Btu in 2040, primarily because of growth in CNG use for transit buses, which represents 28% of total energy consumption by buses in 2040. Use of CNG by LDVs and LNG by domestic marine vessels remains relatively minor, at 19.1 trillion Btu and 1.5 trillion Btu in 2040, or 2% and 0.2% of each mode's energy consumption, respectively.

Electricity demand

Growth in electricity use slows, but use still increases by 29% from 2012 to 2040

Figure MT-29. U.S. electricity demand growth in the Reference case, 1950-2040 (percent)



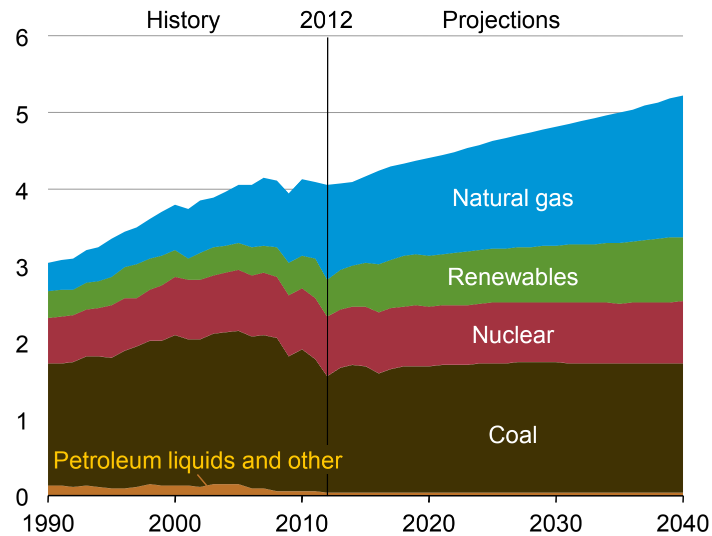
Growth of electricity demand (including retail sales and direct use) has slowed in each decade since the 1950s, from 9.8%/year from 1949 to 1959 to only 0.7%/year since 2000. In the AEO2014 Reference case, electricity demand growth remains relatively low, as rising demand for electric services is offset by efficiency gains from new appliance standards and investments in energy-efficient equipment (Figure MT-29). Total electricity demand grows by 29% (0.9%/year), from 3,826 billion kilowatthours (kWh) in 2012 to 4,954 billion kWh in 2040.

Retail electricity sales grow by 25% (0.8%/year) in the Reference case, from 3,686 billion kWh in 2012 to 4,623 billion kWh in 2040. Population shifts to warmer regions with greater cooling requirements affect both residential and commercial electricity sales. Residential electricity sales grow by 21%, to 1,657 billion kWh in 2040, with cooling needs offset by more efficient appliances and light bulbs. Electricity sales to the commercial sector rise by 27%, to 1,675 billion kWh in 2040, with continuous growth in demand for electrical devices and equipment. Sales to the industrial sector rise by 30%, initially in the primary metals and bulk chemical industries and later in the food, construction, and metal-based durables industries.

Electricity demand varies with different assumptions about economic growth, advances in energy-efficient technologies, and electricity prices. In the High Economic Growth case, electricity demand grows by 41% from 2012 to 2040, compared with 20% in the Low Economic Growth case and only 14% in the Best Available Demand Technology case. In the High Oil and Gas Resource Case, a 2% decline in electricity prices from 2012 to 2040, because of greater natural gas availability, results in demand growth of 35% over the same period. In contrast, in the Reference Case, electricity prices increase by 13% over the projection, while demand increases by 29%.

By 2035, natural gas surpasses coal as the largest source of U.S. electricity generation

Figure MT-30. Electricity generation by fuel in the Reference case, 1990-2040 (trillion kilowatthours)

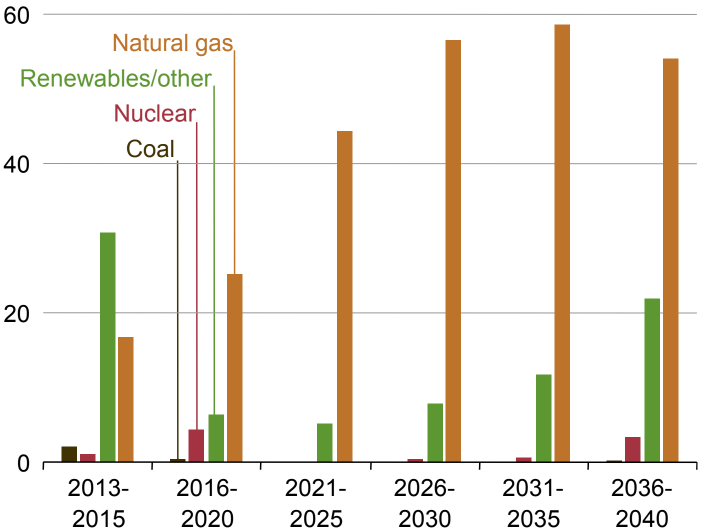


The share of electricity generated from natural gas grows steadily in the AEO2014 Reference case (Figure MT-30). The shift to natural gas occurs primarily as a result of its relatively low cost and coal-fired capacity retirements, although coal maintains the largest share of the generation mix through most of the projection. Changes in fuel mix are primarily a function of natural gas prices, which drive dispatch decisions for both coal and natural gas plants. Although a significant number of coal plants are retired early in the projection, the reduction in coal-fired generation is not proportional to the decline in capacity, because many of the coal plants projected to be retired currently operate at low capacity factors.

After 2020, increasing demand for electricity creates a need for new generating capacity, and natural gas plants account for more than 70% of all new capacity in the projection. As a result, the natural gas share of total electricity generation surpasses the coal share in 2035. Generation from nuclear power plants is relatively constant through 2040, increasing by an average of 0.2%/year, as 10 gigawatts (GW) of new capacity is brought online and 5 GW of older capacity is retired, and the nuclear share of total generation declines while the natural gas and renewable shares increase. Renewable generation grows by an average of 1.9%/year from 2012 through 2040 and makes up an increasing share of the generation mix in the Reference case. The non-hydropower share of total renewable generation increases from 45% in 2012 to 65% in 2040. The generation mix is sensitive to fuel prices and future policies and, therefore, varies significantly across the AEO2014 alternative cases.

Most new capacity uses natural gas and renewables

Figure MT-31. Electricity generation capacity additions by fuel type, including combined heat and power, in the Reference case, 2013-40 (gigawatts)



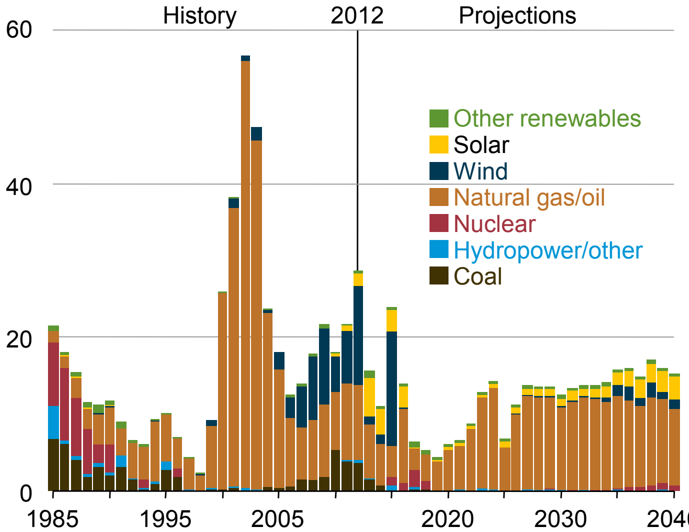
Decisions to add capacity, and the choice of fuel for new capacity, depend on a number of factors [*8*]. With growing electricity demand and the retirement of 97 GW of existing capacity, 351 GW of new generating capacity [*9*] is added in the AEO2014 Reference case from 2013 to 2040 (Figure MT-31).

Natural gas-fired plants account for 73% of capacity additions from 2013 to 2040 in the Reference case, compared with 24% for renewables, 3% for nuclear, and 1% for coal. Escalating construction costs have the largest impact on capital-intensive technologies, which include nuclear, coal, and renewables. However, federal tax incentives, nuclear loan guarantees, state energy programs, and rising prices for fossil fuels can increase the competitiveness of renewable and nuclear generating capacity. Federal and state environmental regulations also affect the use of fossil fuels, particularly coal, as does uncertainty about future limits on GHG emissions and other possible environmental programs (reflected in the Reference case by adding 3 percentage points to the cost of capital for new coal-fired capacity without carbon controls).

Uncertainty about demand growth and fuel prices also affects capacity planning. Capacity additions from 2013 to 2040 range from 263 GW in the Low Economic Growth case to 482 GW in the High Economic Growth case. In the Low Oil and Gas Resource case, with higher natural gas prices, new gas-fired capacity totals 181 GW, or 49% of total additions, from 2013 to 2040. In the High Oil and Gas Resource case, with natural gas prices that are lower than in the Reference case, 323 GW of new natural gas-fired capacity is added from 2013 to 2040, accounting for 83% of total new capacity.

Additions to power plant capacity slow after 2016 but accelerate beyond 2023

Figure MT-32. Additions to electricity generating capacity in the Reference case, 1985-2040 (gigawatts)



Past investments in electricity generation capacity have gone through boom-and-bust cycles, with periods of slow growth followed by rapid growth in response to changing expectations for future electricity demand and fuel prices, as well as changes in the industry, such as restructuring. A construction boom in the early 2000s saw capacity additions averaging 35 GW/year from 2000 to 2005, but the average dropped to 19 GW/year from 2006 to 2012 (Figure MT-32).

In the AEO2014 Reference case, capacity additions from 2013 to 2040 total 351 GW, including new plants in the power sector as well as end-use generators. Additions through 2016 average 16 GW/year, with 52% consisting of renewable plants built to take advantage of federal tax incentives and to meet state RFS. Eligibility rules for the wind production tax credit (PTC) allow new wind capacity coming online before 2016 to qualify, leading to a large increase just at the deadline.

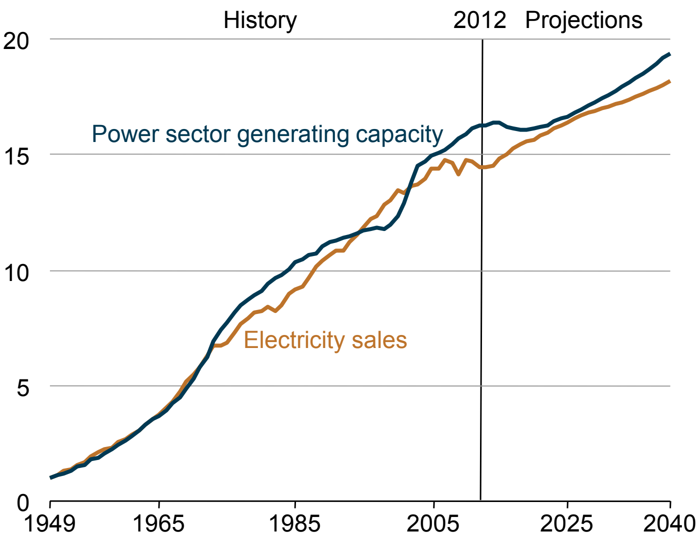
Annual capacity additions drop significantly after 2016 and remain below 9 GW/year until 2023, while existing capacity is adequate to meet relatively slow demand growth in most regions and satisfy renewable requirements under state standards. From 2025 to 2040, annual builds average 14 GW/year, as what was previously excess capacity is again needed. About 79% of the capacity added from 2025 to 2040 is fueled with natural gas, given higher construction costs for other types of capacity and uncertainty about the prospects for future limits on GHG emissions.

Uncertainty about electricity demand growth affects annual capacity additions. In the Low Economic Growth case, annual additions average 10 GW/year from 2025 to 2040; in the High Economic Growth case, they increase to an average of 20 GW/year over the same period.

Electricity sales

Growth in power generating capacity parallels rising sales of electricity

Figure MT-33. Electricity sales and power sector generating capacity in the Reference case, 1949-2040 (indices, 1949 = 1.0)



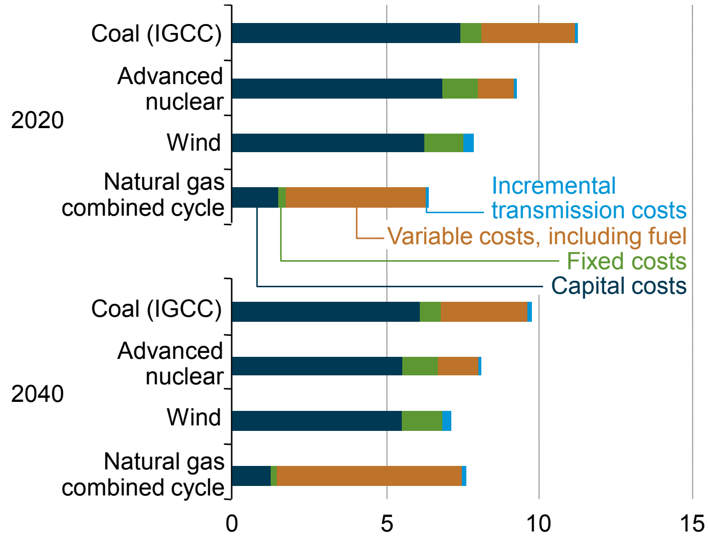
In the long term, growth in generating capacity parallels growth in electricity demand. However, unexpected shifts in demand or changes that affect capacity investment decisions can cause imbalances that may take years to work out. Capacity growth has outpaced demand since the 2007-09 economic recession that resulted in flat or declining demand. Low natural gas prices and tax incentives for renewable technologies have contributed to increases in those capacity types, even while most regions had sufficient capacity to serve load with an adequate reserve margin.

Figure MT-33 shows indexes summarizing relative changes in total power sector generating capacity and electricity sales. During the 1950s and 1960s, capacity and demand indexes tracked closely; but energy crises in the 1970s and 1980s slowed demand growth, with capacity additions outpacing demand for more than 10 years, as planned units continued to come online. Demand and capacity were aligned again in the mid-1990s, but in the late 1990s uncertainty about industry deregulation led to a downturn in capacity expansion, and another period of imbalance followed, with demand growth exceeding capacity growth.

In 2000, a boom in construction of new natural gas-fired plants brought capacity back into balance with demand, but capacity continued to grow, creating excess. Construction of new wind capacity also grew after 2000. Excess capacity remains in the early years of the AEO2014 Reference case, until retirements eventually bring capacity growth and demand growth back into balance after 2023. In the later years, total capacity grows at a rate slightly higher than demand growth, due in part to an increase in 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 MT-34. Average levelized electricity costs for new power plants, excluding subsidies, in the Reference case, 2020 and 2040 (2012 cents per kilowatthour)



Technology choices for new generating capacity are based largely on capital, operating, and transmission costs [*10*]. Coal, nuclear, and wind plants are capital-intensive (Figure MT-34), 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 capital cost recovery periods, which vary with technology. Fuel costs vary with operating efficiency, fuel price, and transportation costs.

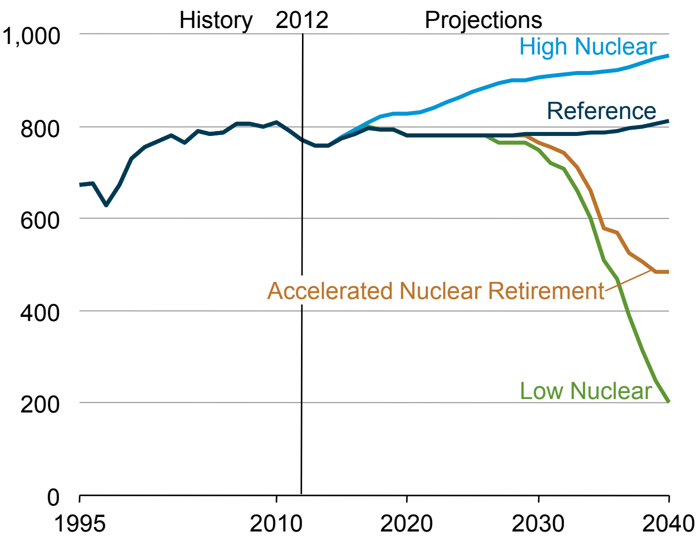
Capital costs can decline over time as developers gain technology experience, with the largest rate of decline observed for new technologies. In the AEO2014 Reference case, the capital costs of new technologies are adjusted upward initially to compensate for the optimism inherent in early estimates of project costs, then they 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.

In addition to considerations of levelized costs [*11*], some technologies and fuels receive subsidies, such as production or investment tax credits. Also, new plants must satisfy local and federal emissions standards and be compatible with the utility's load profile to maximize revenue.

Regulatory uncertainty also affects capacity planning. Laws and regulations may require new coal plants to include carbon control and sequestration equipment, resulting in higher material, labor, and operating costs. Because nuclear and renewable power plants (including wind plants) do not emit greenhouse gases, their costs are not directly affected by these specific sources of regulatory uncertainty.

Nuclear electricity generation varies with license renewals, uprates, and operating costs

Figure MT-35. Nuclear electricity generation in four cases, 1995-2040 (billion kilowatthours)



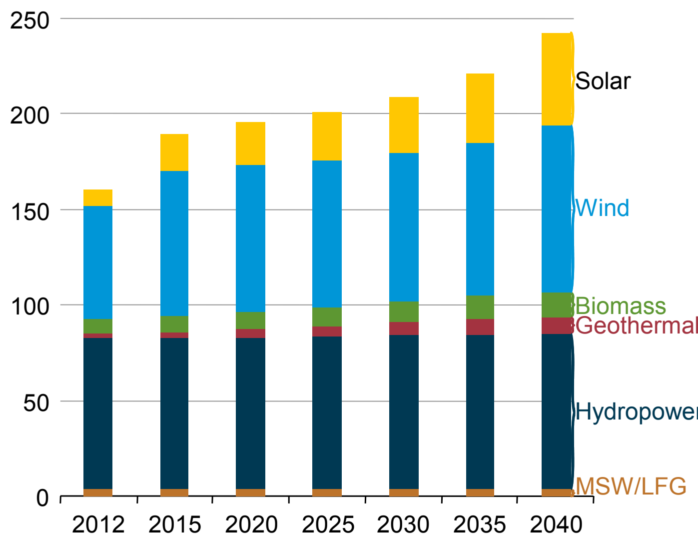
Projections of nuclear capacity and generation are influenced by assumptions about the potential for capacity uprates, new licensing requirements, future operating costs, and outside influences such as natural gas prices and incentives for other generating technologies. In the Reference case, nuclear capacity and generation remain relatively flat, with early retirements offset by new additions (Figure MT-35).

As discussed in AEO2014 Issues in focus, the Accelerated Nuclear Retirement case assumes no new nuclear builds beyond those currently under construction; that all existing units are retired by 60 years of age; and that nonfuel operating costs at existing nuclear plants increase by 3% annually, similar to recent rates. In this case, 42 gigawatts (GW) of nuclear capacity is retired, mostly from 2030 to 2040. The Low Nuclear case combines those assumptions with the High Oil and Gas Resource case and the No Sunset case. Lower natural gas prices make existing and new natural gas units more economical, and together with tax credits for newly added renewable capacity, they lower electricity market prices. With rising operating costs for nuclear plants and lower electricity prices, 77 GW of nuclear capacity is retired before 60 years of life. The retired nuclear capacity is replaced primarily by natural gas capacity, leading to a 6% increase in CO_2 emissions in the electric power sector in 2040.

The High Nuclear case assumes more uprates of existing units, adding 6.0 GW of capacity, and the addition of 12.6 GW of planned capacity through 2027. As a result, total nuclear generation in 2040 is 17% higher than in the Reference case, reducing the need for additional natural gas-fired generation.

Solar photovoltaics and wind dominate renewable capacity growth

Figure MT-36. Renewable electricity generating capacity by energy source, including end-use capacity in the Reference case, 2012-40 (gigawatts)



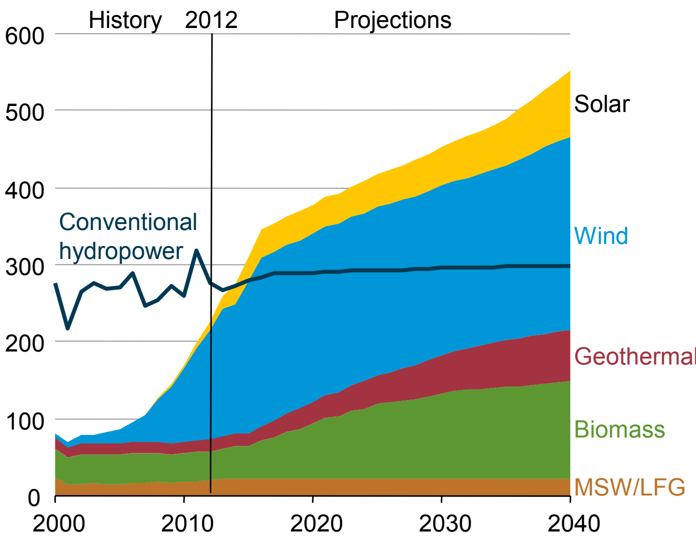
Total renewable generating capacity grows by 52% from 2012 to 2040 in the AEO2014 Reference case. Nonhydropower renewable capacity, particularly wind and solar, nearly doubles (Figure MT-36) and accounts for almost all of the growth in renewable capacity.

Solar power leads the growth in renewable capacity, increasing from less than 8 GW in 2012 to more than 48 GW in 2040. Wind capacity increases from less than 60 GW in 2012 to 87 GW in 2040, the second-largest amount of new renewable capacity. Although geothermal capacity more than triples and biomass capacity nearly doubles in the projection, combined they account for less than 15% of renewable capacity additions. Wind is the top source of nonhydropower renewable capacity in the projection, surpassing the hydropower share in 2036.

Renewable capacity growth is supported by a variety of federal and state policies, particularly state renewable portfolio standards (RPS) and federal tax credits. However, the impact of those policies is limited later in the projection period, because individual state renewable targets stop increasing by 2025, and projects must generally be online by 2016 to qualify for currently available federal tax credits. In addition, growth in electricity demand is modest and natural gas prices are relatively low after 2025. Renewable capacity grows by an average of 0.7%/year from 2020 to 2030, compared with 3.8%/year from 2010 to 2020. However, as natural gas prices rise over the projection period, renewable capacity becomes an increasingly cost-competitive option in some regions, and the total grows by an average of 1.5%/year overall from 2030 to 2040.

Total generation from wind, solar, and other renewables surpasses hydropower

Figure MT-37. Renewable electricity generation by type, all sectors, in the Reference case, 2000-40 (billion kilowatthours)



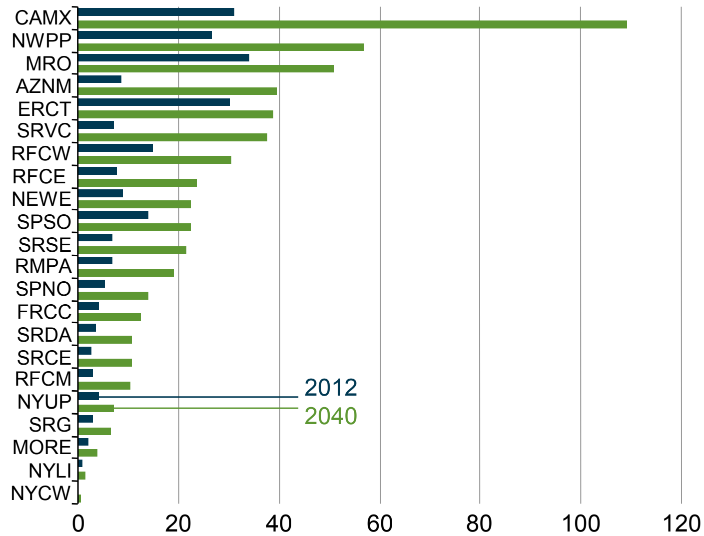
Total renewable electricity generation grows by 1.9%/year on average in the Reference case, from 502 billion kWh in 2012 to 851 billion kWh in 2040. Nonhydropower renewables, averaging 3.2%/year growth, account for nearly all of the growth, with their total surpassing hydropower (the previous leader of renewable generation) in 2014 and accounting for about two-thirds of all renewable generation in 2040 (Figure MT-37).

Solar energy is the fastest-growing source of renewable generation, increasing by 7.5%/year from 2012 to 2040, almost exclusively as a result of increased photovoltaic capacity in both the electric power (central-station) and end-use (customer-sited) sectors. Wind generation grows by an average of 2.0%/year but provides the largest absolute increase in renewable generation. From 2012 to 2016, wind power developers take advantage of the existing federal PTC, which requires plants to be under construction by the end of 2013 to qualify.

Geothermal power is the second-fastest-growing source of renewable electricity generation in the Reference case, increasing from less than 16 billion kWh in 2012 to 67 billion in 2040—a 5.4% average annual growth rate. Biomass generation also grows significantly, increasing by an average of 4.4%/year from 2012 to 2040, primarily as a result of increased use of co-firing technology in the electric power sector in the near- to mid-term. Co-firing is encouraged by state-level policies and increasing regional cost-competitiveness with coal. In the long run, the growth of biomass generation is supported by increased capacity at dedicated biomass plants in the electric power sector, as well as combined heat and power plants in the industrial sector.

California leads renewable electricity generation growth

Figure MT-38. Regional nonhydropower renewable electricity, including end-use generation, in the Reference case, 2012 and 2040 (billion kilowatthours)



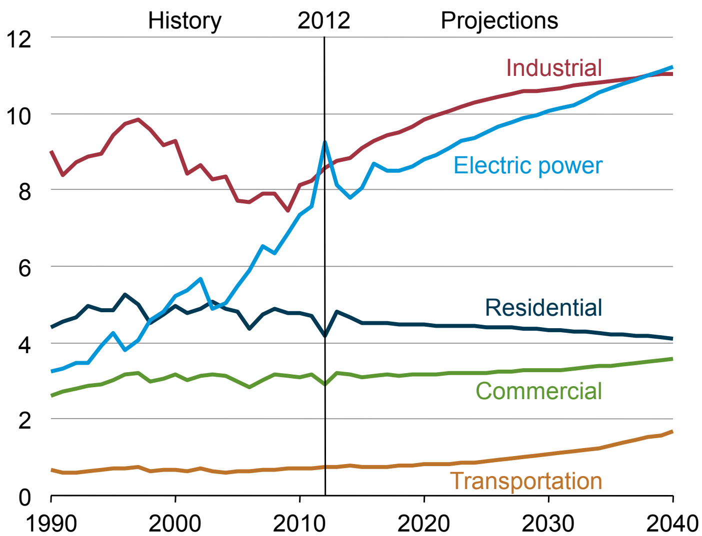
In the AEO2014 Reference case, nonhydropower renewable generation increases from 2012 to 2040 in all modeled electricity regions (for a map of the regions and definition of acronyms, see Appendix F). Its growth is faster in some regions than in others, and the penetration in the generation mix and resulting increases in generation vary substantially among regions (Figure MT-38).

Regional growth in nonhydropower renewable generation is mainly driven by three factors: state RPS, availability of renewable energy resources, and cost competiveness with fossil fuel technologies. Factors such as electricity demand growth, non-RPS policies (such as net metering), and electricity prices also affect the rate of growth, which tends to be strongest in regions where a combination of factors is in place.

The WECC California (CAMX) region accounts for both the highest absolute level of nonhydropower renewable generation in 2040 and the largest growth from 2012 to 2040, which is supported by an aggressive RPS, availability of solar, wind, and geothermal resources, and relatively high electricity prices. The AZNM (Arizona, New Mexico, and Nevada) and SRVC (Virginia, North Carolina, and South Carolina) regions show the next-highest increases in nonhydropower renewable generation from 2012 to 2040. In the AZNM region, growth is supported by mandatory RPS standards, above-average electricity demand growth, and the availability of solar and wind resources. Although Virginia and South Carolina do not have mandatory policies in place, the SRVC region has robust biomass and solar resources and relatively high fossil fuel prices.

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

Figure MT-39. Natural gas consumption by sector in the Reference case, 1990-2040 (trillion cubic feet)



U.S. total natural gas consumption grows from 25.6 trillion cubic feet (Tcf) in 2012 to 31.6 Tcf in 2040 in the AEO2014 Reference case. Natural gas use increases in all of the end-use sectors except residential (Figure MT-39). Natural gas use for residential space heating declines as a result of population shifts to warmer regions of the country and improvements in appliance efficiency.

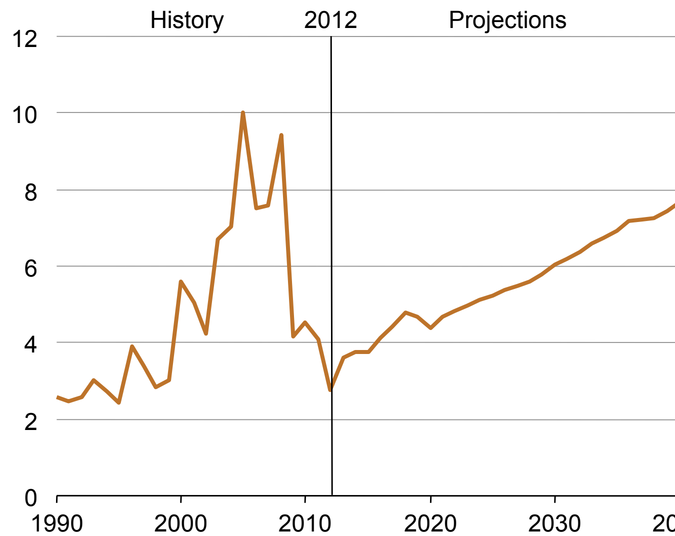
Consumption of natural gas for electric power generation grows by about 2 Tcf and makes up about 33% of the increase in total natural gas consumption by 2040. Relatively low natural gas prices make natural gas an attractive fuel for serving increased load. Natural gas is also the fuel most often used to replace older coal-fired generation as it is retired.

From 2012 to 2040, natural gas consumption in the industrial sector increases by 2.5 Tcf, an average of 0.9%/year, representing about 26% of the total increase in natural gas consumption. As industrial output grows, the energy-intensive industries take advantage of relatively low natural gas prices, particularly through 2028. After 2028, industrial sector consumption of natural gas continues to grow but at a somewhat slower rate, in response to rising prices.

Although transportation use currently accounts for only a small portion of total U.S. natural gas consumption, natural gas use by heavy-duty vehicles (HDVs), trains, and ships shows the largest percentage growth of any fuel in the projection. Consumption in the transportation sector, excluding natural gas use at compressor stations, grows from about 40 billion cubic feet (Bcf) in 2012 to 850 Bcf in 2040.

Natural gas prices rise with an expected increase in production costs

Figure MT-40. Annual average Henry Hub spot natural gas prices in the Reference case, 1990-2040 (2012 dollars per million Btu)



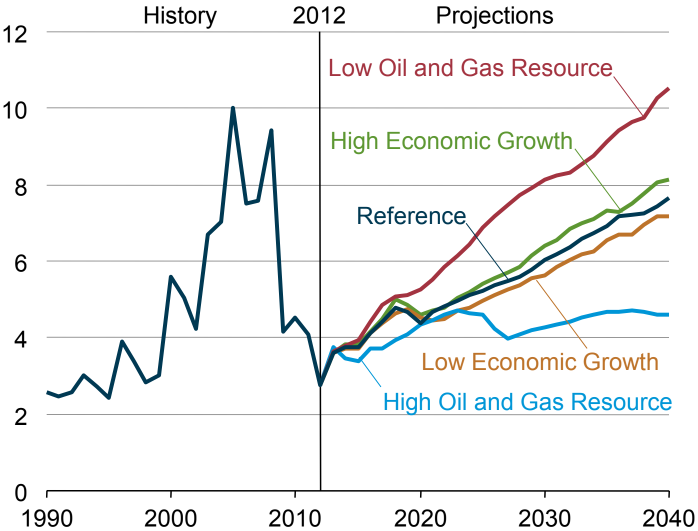
Average annual U.S. natural gas prices have remained relatively low over the past several years as a result of the availability of abundant domestic resources and the application of improved production technologies. To provide the supplies necessary to meet growth in natural gas consumption and a rise in exports in the AEO2014 Reference case, producers move into areas where the recovery of natural gas is more difficult and expensive, which leads to an increase in Henry Hub spot prices over the projection period. Henry Hub spot prices for natural gas increase by an average of 3.7%/year in the Reference case, from $2.75/million Btu (MMBtu) in 2012 to $7.65/MMBtu (2012 dollars) in 2040 (Figure MT-40).

Growth in demand for natural gas, largely from the electric power and industrial sectors and for liquefied natural gas (LNG) exports, results in upward pressure on prices, particularly in the 2015-18 period. Delivered prices to residential, commercial, industrial, and electric power consumers generally rise with Henry Hub prices in the projection, but the lower 48 average spot price increases at a slightly slower rate than the Henry Hub spot price, because regional production growth in areas that do not serve the Henry Hub is somewhat faster than growth in areas that supply the Henry Hub. In particular, dry gas production in the Marcellus shale play, which predominantly serves the Northeastern and Mid-Atlantic regions, grows from 1.9 Tcf in 2012 to 5.0 Tcf in 2022 in the Reference case, before declining to 4.6 Tcf in 2040. Total onshore production in the Northeast region grows on average by 3.2%/year, from 3.3 Tcf in 2012 to 8.1 Tcf in 2040, while combined onshore and offshore production in the Gulf region grows by 2.1%/year, from 7.3 Tcf in 2012 to 13.0 Tcf in 2040.

Natural gas prices

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

Figure MT-41. Annual average Henry Hub spot prices for natural gas in five cases, 1990-2040 (2012 dollars per million Btu)



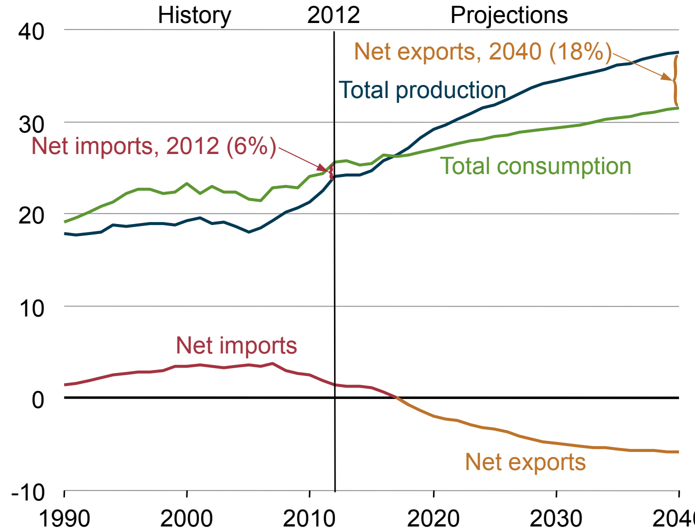
The projection of natural gas prices depends on many factors, including macroeconomic growth rates and expected rates of resource recovery from natural gas wells. Higher rates of economic growth lead to increased consumption of natural gas, primarily in response to their effects on housing starts, commercial floorspace, and industrial output. In the High Economic Growth case, higher levels of consumption result in more rapid increases both in depletion of natural gas resources and in the cost of developing new production, pushing natural gas prices higher. The converse is true in the Low Economic Growth case (Figure MT-41). In the High and Low Economic Growth cases, the price rises by 4.0%/year and 3.5%/year, respectively, compared with 3.7%/year in the Reference case.

The rate of resource recovery from oil and natural gas wells has a direct impact on the cost per unit of production and, in turn, prices. The High Oil and Gas Resource case assumes 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 than in the Reference case. The Low Oil and Gas Resource case assumes lower estimated ultimate recovery of natural gas from each shale well or tight well than in the Reference case. In the Low and High Oil and Gas Resource cases, Henry Hub spot natural gas prices increase by 4.9%/year and 1.8%/year, respectively. (An article in the Issues in focus section, "U.S. tight oil production: Alternative supply projections and an overview of EIA's analysis of well-level data aggregated to the county level," provides more information on the alternative resource cases.)

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 increases in natural gas exports and demand, which place some upward pressure on natural gas prices.

With production growing faster than use, the U.S. becomes a net exporter of natural gas

Figure MT-42. Total natural gas production, consumption, and imports in the Reference case, 1990-2040 (trillion cubic feet)



In the AEO2014 Reference case, natural gas production grows by an average rate of 1.6%/year from 2012 to 2040, more than double the 0.8% annual growth rate of total U.S. consumption over the period. The growth in production meets increasing demand and exports (liquefied natural gas [LNG] and pipeline exports), while also making up for a drop in natural gas imports. The United States becomes a net exporter of natural gas before 2020.

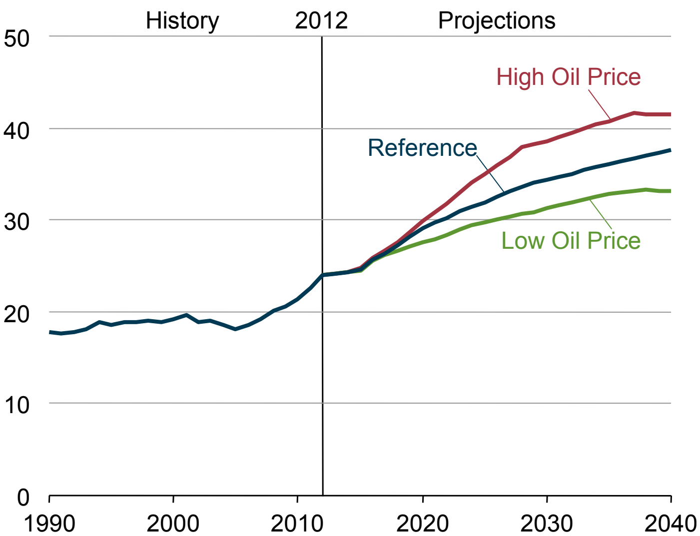
The development of shale gas resources spurs growth in natural gas production, with producers seeing higher prices as a result of growing demand, especially from both the industrial and electricity generation sectors. Growing LNG exports also support higher natural gas prices.

The United States transitions from being a net importer of 1.5 Tcf of natural gas in 2012 to a net exporter of 5.8 Tcf in 2040, with 88% of the rise in net exports (6.5 Tcf) occurring by 2030, followed by slower growth through 2040 (Figure MT-42).

Net LNG exports, primarily to Asia, increase by 3.5 Tcf from 2012 to 2030, then remain flat through 2040. Prospects for future LNG exports are uncertain, depending on many factors that are difficult to anticipate. The increase in net LNG exports to Asia through 2030 accounts for 55% of the rise in total net natural gas exports, with the remainder coming from decreased net pipeline imports from Canada and increased net pipeline exports to Mexico. Net pipeline imports from Canada drop from 2.0 Tcf in 2012 to 0.4 Tcf in 2030, mainly as a result of lower imports to the western United States. Imports from Canada increase to 0.7 Tcf in 2040, with higher imports into the northeastern United States. In contrast, net pipeline exports to Mexico grow steadily, from 0.6 Tcf in 2012 to 3.1 Tcf in 2040.

U.S. natural gas production, use, and exports all are affected by oil prices

Figure MT-43. U.S. natural gas production in three cases, 1990-2040 (trillion cubic feet per year)



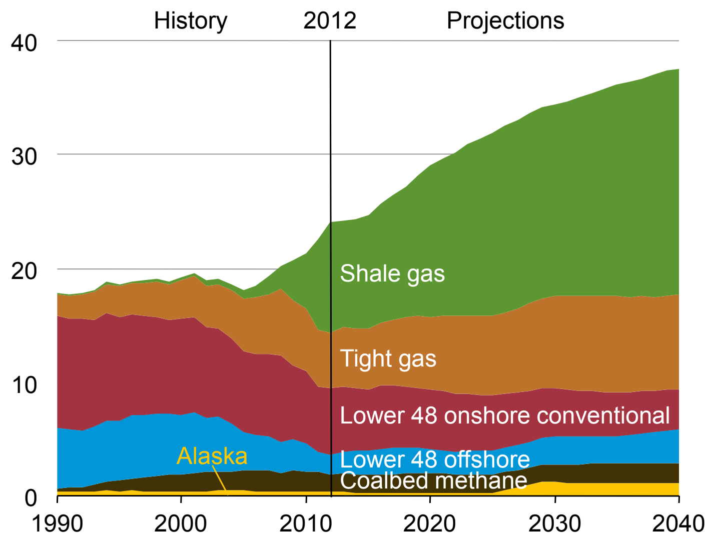
U.S. natural gas production is affected by crude oil prices primarily through changes in natural gas consumption and exports. Across the oil price cases, the largest changes in consumption are seen for natural gas consumed in transportation and natural gas exported as LNG.

The profitability of natural gas as a transportation fuel or as LNG for export depends primarily on the price differential between crude oil and natural gas. For example, in the Low Oil Price case, the average difference between oil prices and natural gas prices from 2012 through 2040 is about $7.70 per million Btu (MMBtu). With that low price differential, virtually no natural gas is consumed in the transportation sector, and little LNG is exported. In the High Oil Price case, in contrast, the average price difference is about $21.90/MMBtu, which provides substantial incentive for direct use of natural gas in transportation and for conversion to LNG for export.

Across the oil price cases, total natural gas production varies by 8.3 Tcf in 2040 (Figure MT-43), with changes in LNG exports accounting for 6.3 Tcf and changes in direct consumption for transportation accounting for 2.2 Tcf. The increase in LNG exports and transportation consumption is offset to some extent by lower natural gas consumption in other sectors, with spot prices for natural gas from 2012 to 2040 averaging about $0.70/MMBtu higher in the High Oil Price case than in the Low Oil Price case.

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

Figure MT-44. U.S. natural gas production by source in the Reference case, 1990-2040 (trillion cubic feet)



The 56% increase in total natural gas production from 2012 to 2040 in the AEO2014 Reference Case results from increased development of shale gas, tight gas, and offshore natural gas resources (Figure MT-44). Shale gas production is the largest contributor, growing by more than 10 Tcf, from 9.7 Tcf in 2012 to 19.8 Tcf in 2040. The shale gas share of total U.S. natural gas production increases from 40% in 2012 to 53% in 2040. Tight gas production and offshore gas production increase by 73% and 78%, respectively, from 2012 to 2040, but their shares of total production remain relatively constant.

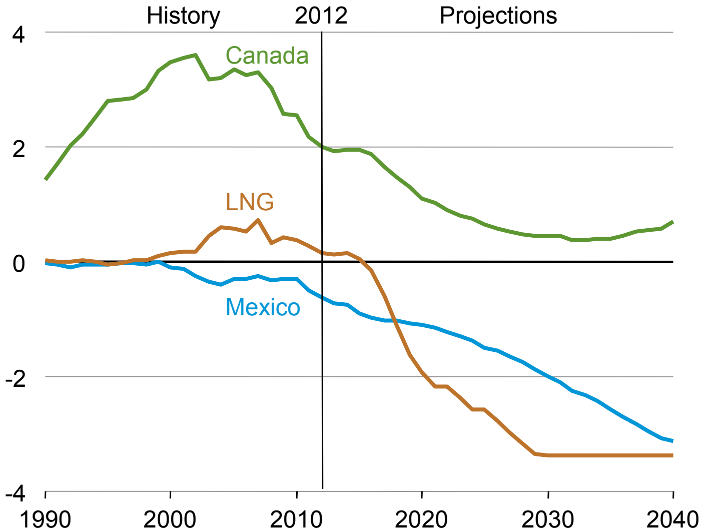
From 2017 to 2022, U.S. offshore natural gas production declines by 0.3 Tcf, as offshore exploration and development activities are directed primarily toward oil resources in the Gulf of Mexico. Offshore natural gas production increases after 2022, growing to 2.9 Tcf in 2040, as natural gas prices rise.

Alaska's natural gas production also increases during the projection period, because of Alaska LNG exports to overseas customers, beginning in 2026 and increasing to 0.8 Tcf (2.2 Bcf/d) in 2029. Alaska's LNG exports level off at 0.8 Tcf per year over the last decade of the projec-tion. Alaska's total natural gas production in 2040 is 1.2 Tcf.

Although U.S. natural gas production rises throughout the projection, the mix of sources changes over time. Onshore nonassociated production (from sources other than tight gas, shale gas, and coalbed methane) declines from 3.9 Tcf in 2012 to 1.6 Tcf in 2040, and in 2040 it accounts for only about 4% of total domestic production, down from 16% in 2012.

U.S. exports to North American and overseas gas markets increase as gas production rises

Figure MT-45. U.S. net imports of natural gas by source in the Reference case, 1990-2040 (trillion cubic feet)



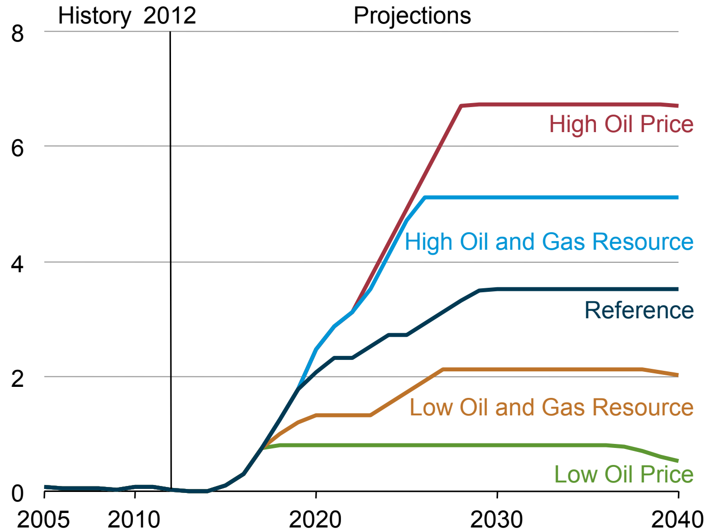
With relatively low natural gas prices in the AEO2014 Reference case, the United States becomes a net exporter of natural gas in 2018, with net exports growing to 5.8 Tcf in 2040. Most of the projected growth in exports consists of LNG exported to overseas markets. From 2012 to 2040, U.S. net exports of LNG increase by 3.5 Tcf (Figure MT-45), including 0.8 Tcf of LNG originating in south-central Alaska, with the remaining volumes originating from export terminals located along the Atlantic and Gulf coasts. In general, future U.S. LNG exports 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 U.S. and international gas markets, and the pace of natural gas supply growth outside the United States.

The next-largest growth market for U.S. natural gas exports is pipeline exports to Mexico, which increase from 0.6 Tcf in 2012 to 3.1 Tcf in 2040. The increase in exports to Mexico reflects a growing gap between Mexico's natural gas consumption and production. However, Mexico's recently enacted legislation to restructure its oil and gas industry could reduce the need for U.S. natural gas exports to Mexico in the future.

Net natural gas imports from Canada decline through 2033, when they reach a low point of about 0.4 Tcf. After 2033, higher natural gas prices in the lower 48 improve the economics of Canadian natural gas exports to the U.S. West Coast. In 2040, net U.S. imports of natural gas from Canada total about 0.7 Tcf.

LNG export growth depends on price and productivity assumptions

Figure MT-46. U.S. exports of liquefied natural gas in five cases, 2005-40 (trillion cubic feet)



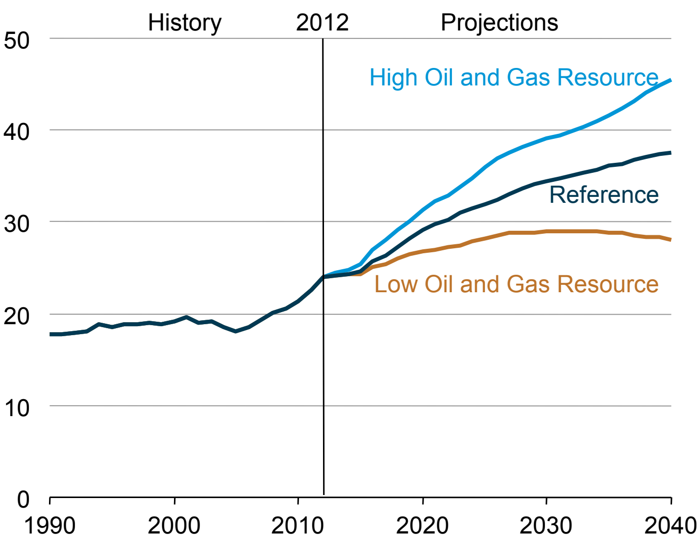
In the AEO2014 Reference case, growing natural gas production from shale gas and tight oil formations supports an increase in U.S. exports of LNG and pipeline gas. Net exports of LNG increase by 3.5 Tcf from 2012 to 2040, representing 48% of the total increase in U.S. natural gas net exports over the period. The United States becomes a net LNG exporter in 2016, with gross exports reaching their peak level of 3.5 Tcf in 2030.

The United States is a net LNG exporter in all of the AEO2014 oil price and resource cases; however, LNG export levels vary significantly by case. In the High Oil Price case, where both global LNG demand and LNG prices are higher than in the Reference case, LNG exports increase to 6.7 Tcf in 2028 and remain at that level through 2040 (Figure MT-46). Conversely, in the Low Oil Price case, gross LNG exports increase to only 0.8 Tcf in 2018, where they remain through most of the projection period. The LNG export projections in AEO2014 are based on a generalized economic evaluation and do not reflect a specific evaluation or knowledge of decisions on pending LNG export applications.

In the High Oil and Gas Resource case, large production increases put downward pressure on U.S. natural gas prices, and as a result LNG exports climb to 5.1 Tcf after 2025. The Low Oil and Gas Resource case assumes lower natural gas production and higher domestic gas prices. Gross LNG exports in the Low Oil and Gas Resource case reach 2.1 Tcf by 2027.

U.S. natural gas production rates depend on resource availability and production costs

Figure MT-47. U.S. natural gas production in three cases, 1990-2040 (trillion cubic feet per year)



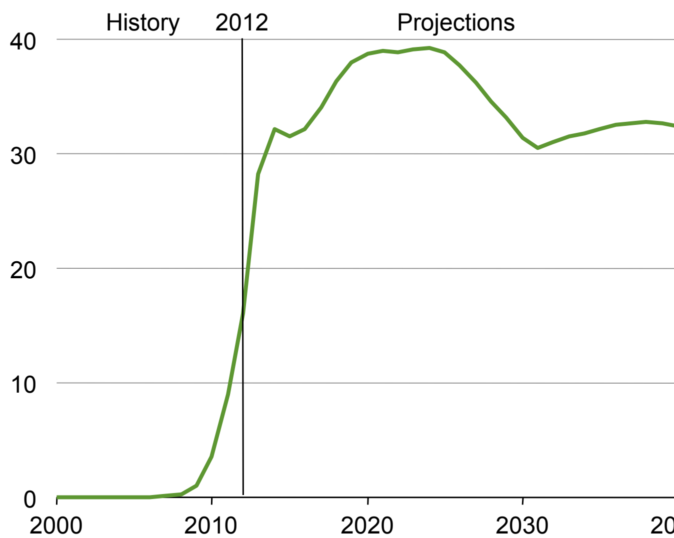
Prospects for production from tight oil and shale gas resources are uncertain, both because large portions of the formations have little or no production history, and because future technology could increase well productivity while reducing costs. The Low Oil and Gas Resource and High Oil and Gas Resource cases illustrate the potential impacts of changes in the Reference case assumptions regarding technology advances and the resource size and quality.

The High Oil and Gas Resource case assumes (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 (EUR) per well and closer well spacing; (2) tight oil development in Alaska; (3) higher estimates of offshore resources in Alaska and the lower 48 states; and (4) higher rates of long-term technology improvement. In the High Resource case, higher well productivity reduces development and production costs per unit, resulting in more and earlier resource development than in the Reference case. With the greater abundance of less-expensive shale gas resources, cumulative shale gas production from 2012 through 2040 totals 540 Tcf, as compared with 442 Tcf in the Reference case. In the Reference case and the High Resource case, total natural gas production in 2040 grows to 37.5 Tcf and 45.5 Tcf per year, respectively.

In the Low Oil and Gas Resource case, which assumes lower tight oil, tight gas, and shale gas resources than in the Reference case, total natural gas production plateaus at just under 29 Tcf per year from 2027 through 2036, then declines to 28.1 Tcf in 2040 (Figure MT-47). Shale gas production peaks in 2030 at 13.1 Tcf and declines to 11.6 Tcf in 2040. From 2012 to 2040, cumulative shale gas production totals 341 Tcf in the Low Oil and Gas Resource case.

Marcellus shale gas production growth changes U.S. natural gas transportation patterns

Figure MT-48. Marcellus shale production share of total U.S. natural gas consumption east of the Mississippi River in the Reference case, 2000-40 (percent)



Historically, natural gas produced in Texas, Louisiana, Oklahoma, and the offshore Gulf of Mexico has been transported to markets east of the Mississippi River. In addition, significant volumes of natural gas have been transported from Canada and the Rocky Mountains to serve the same markets. However, the advent of large-scale natural gas production in the Marcellus shale formation, located in Appalachia, will alter natural gas transportation patterns east of the Mississippi River.

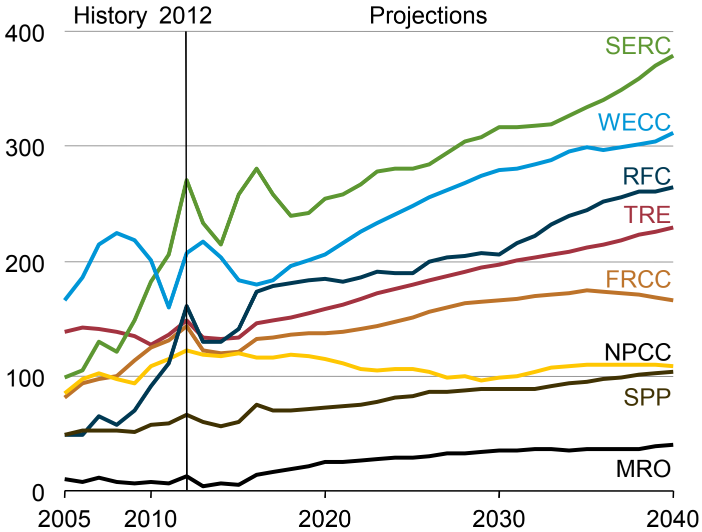
In the AEO2014 Reference Case, natural gas production from the Marcellus shale grows from 1.9 Tcf in 2012 to a peak production volume of about 5.0 Tcf per year from 2022 through 2025. Marcellus shale gas production could provide up to 39% of the natural gas needed to meet demand in markets east of the Mississippi River during that period—up from 16% in 2012. Although Marcellus gas production declines after 2024 in the Reference case, it still provides enough natural gas to meet at least 31% of the region's total demand for natural gas through 2040 (Figure MT-48).

Marcellus natural gas exceeds 100% of the demand projected for the New England and Mid-Atlantic Census Divisions from 2016 through 2040 in the Reference case, requiring transportation of some Marcellus gas to other markets. During the expected peak production period for the Marcellus shale, from 2022 through 2025, its total production exceeds natural gas consumption in the New England and Middle Atlantic regions by more than 1.0 Tcf over the period.

Natural gas consumption

Natural gas-fired generation grows strongly in the electric power sector

Figure MT-49. Natural gas-fired generation in the electric power sector by NERC region in the Reference case, 2005-40 (billion kilowatthours)



Consumption of natural gas by the U.S. electric power sector grows by an average of 0.7%/year from 2012 to 2040 in the AEO2014 Reference case. That growth is equivalent to 42% of the total increase in electricity generation over the period. While the coal-fired share of total generation in the electric power sector declines from 39% in 2012 to 34% in 2040, the natural gas share rises from 29% to 33%.

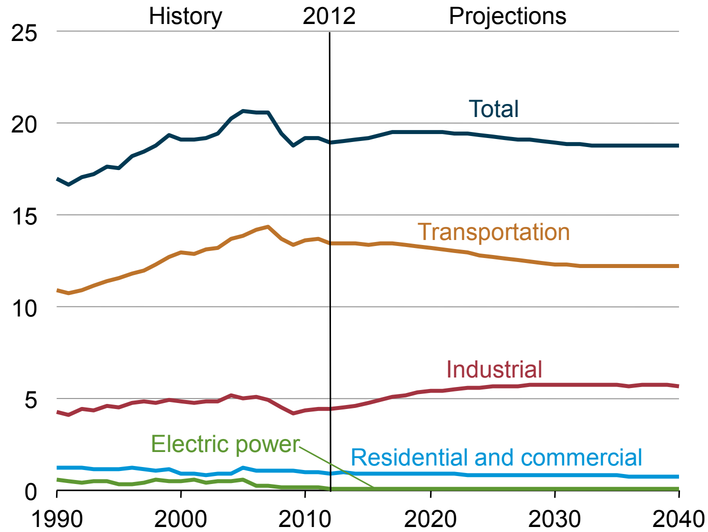
The increase in natural gas-fired generation is generally more pronounced in regions where coal-fired power plants are retired, including the SERC Reliability Corporation (SERC) and ReliabilityFirst Corporation (RFC) regions (Figure MT-49). The retirement of coal-fired capacity in the SERC region from 2012 to 2040, at 12.9 GW, is the country's second largest, and its increase in natural gas-fired generation over the same period, at 109 million MWh, is the largest. The largest decrease in coal-fired capacity (21.7 GW) is in the RFC region, which also has the third-largest increase in natural gas-fired generation, at 103 million MWh.

Two other regions with large increases in natural gas-fired generation in the Reference case are the Western Electricity Coordinating Council (WECC) and the Texas Reliability Entity (TRE). Those two regions do not have large retirements of coal-fired generation capacity, but they do have significant overall growth in electricity demand, most of which is met with natural gas-fired generation. WECC has the country's second-largest increase in natural gas-fired generation from 2012 to 2040 (105 million MWh), and TRE has the fourth-largest increase (81 million MWh).

In the RFC and TRE regions, natural gas-fired generation meets the vast majority of growth in electricity demand through 2040. Despite retirements of coal units, coal generation still meets a significant portion of demand in the SERC region. In the WECC region, renewables meet a significant portion of demand growth.

Led by transportation, petroleum and other liquids consumption declines

Figure MT-50. Consumption of petroleum and other liquids by sector in the Reference case, 1990-2040 (million barrels per day)



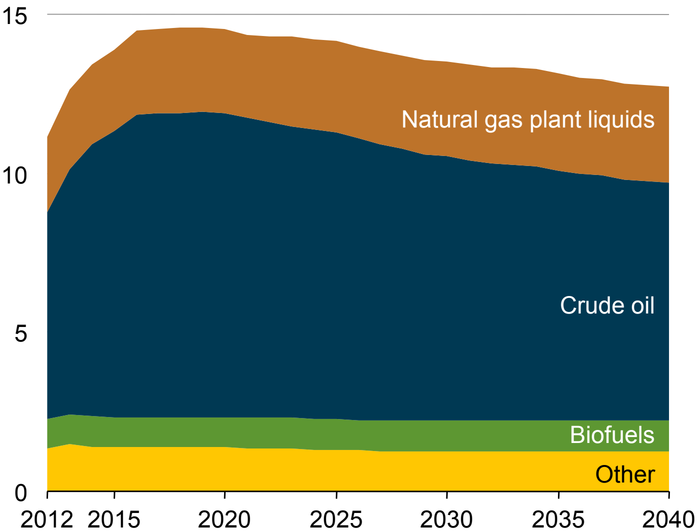
Consumption of petroleum and other liquids remains relatively flat in volumetric terms in the AEO2014 Reference case (Figure MT-50). While the transportation sector accounts for the largest share of total consumption throughout the projection, its share falls from 72% in 2013 to 65% in 2040, as a result of improvements in vehicle efficiency following the incorporation of corporate average fuel economy (CAFE) standards for both light-duty vehicles (LDVs) and heavy-duty vehicles (HDVs). In the industrial sector, consumption in the chemicals industry increases by 1.3 million barrels per day (MMbbl/d) from 2012 to 2040, largely reflecting higher volumes of hydrocarbon gas liquids as the sector benefits from increased U.S. production of natural gas. Consumption in all other industry segments decreases between 2012 and 2040.

Motor gasoline, ultra-low-sulfur diesel fuel, and jet fuel are the primary transportation fuels, all of which can include biofuels and may be supplemented by natural gas. Total motor gasoline consumption increases from 2012 to 2015 before dropping by approximately 2.1 MMbbl/d from 2015 to 2040 in the Reference case, while total diesel fuel consumption increases from 3.4 MMbbl/d in 2012 to 4.3 MMbbl/d in 2040, primarily for use in HDVs.

Both ethanol blending into gasoline and E85 consumption are essentially flat throughout the projection period, as a result of declining gasoline consumption and limited penetration of FFVs. The rapid rise of U.S. crude oil production, combined with the decline in motor gasoline demand and a modest increase in diesel fuel demand, reduces market opportunities for CTL and GTL technologies.

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

Figure MT-51. U.S. production of petroleum and other liquids by source in the Reference case, 2012-40 (million barrels per day)



In the AEO2014 Reference case, petroleum and other liquids supply grows through 2019 as a result of increases in production of tight oil (including condensates) and natural gas plant liquids (NGPL) (Figure MT-51). Total liquids production grows from 11.1 MMbbl/d in 2012 to a peak of 14.6 MMbbl/d in 2019, then drops to 12.7 MMbbl/d in 2040—still above 2012 levels—as tight oil production declines.

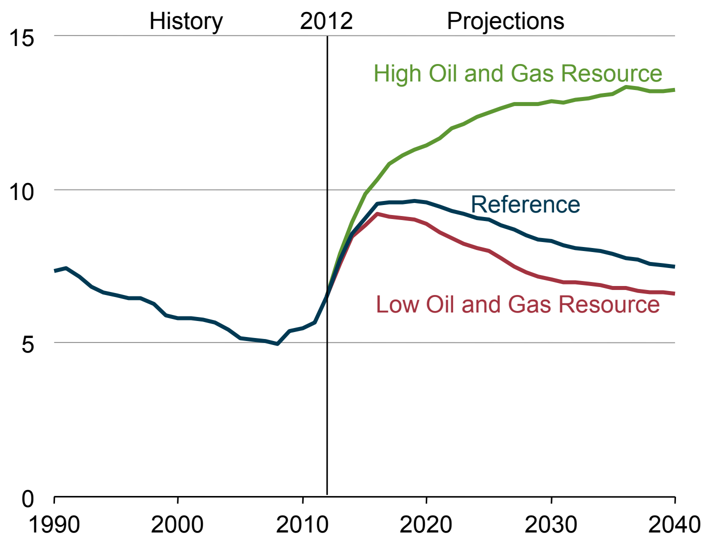
Production of hydrocarbon gas liquids (HGL) [*12*] increases throughout the projection. HGL is a new term introduced in the analysis to account for NGPL produced from natural gas processing plants and fractionators, and the liquefied refinery gases from crude oil in refineries. NGPL production increases from 2.4 MMbbl/d in 2012 to about 3.0 MMbbl/d in 2030, then remains level after 2030, as growth in natural gas production slows.

Domestic ethanol production remains relatively flat, as consumption of motor gasoline decreases and the penetration of ethanol is slowed by the limited availability of flex-fuel vehicles and retrofitted filling stations. Biodiesel production is also constant throughout the projection on the assumption that the U.S. Environmental Protection Agency (EPA) will indefinitely continue the current requirement of 1.28 billion gallons per year under the RFS.

Other biomass-to-liquids production, excluding ethanol and biodiesel, increases by 32,200 bbl/d from 2012 to 2040. However, neither gas-to-liquids (GTL) nor coal-to-liquids (CTL) contributes to domestic liquids production in the Reference case because of the risks associated with their high capital costs, long construction leadtimes, and the possibility that liquids from CTL facilities will not remain price-competitive with crude oil over the lifetimes of the facilities.

U.S. crude oil production rates depend on resource availability and production costs

Figure MT-52. Total U.S. crude oil production in three cases, 1990-2040 (million barrels per day)



Projections of U.S. tight oil production are uncertain, because large portions of the known formations have little or no production history, and because technology improvements could increase well productivity while reducing drilling, completion, and production costs. The High and Low Oil and Gas Resource cases illustrate the potential impacts of changes in the Reference case assumptions regarding technology advances and the resource size and quality.

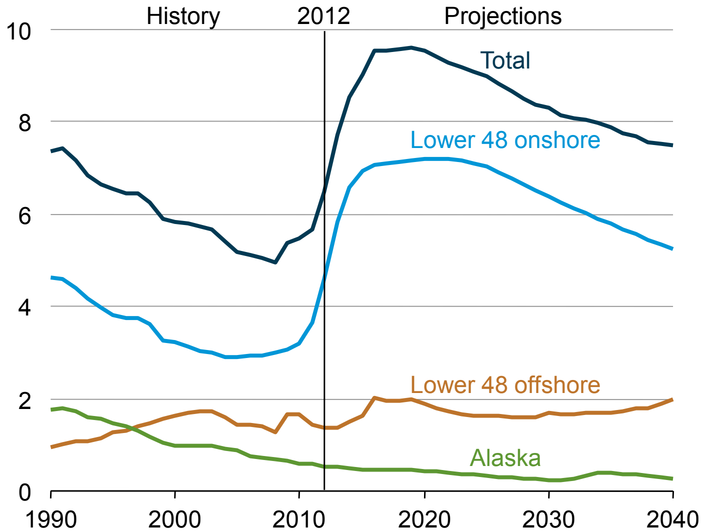
The High Oil and Gas Resource case assumes more onshore lower 48 tight resources than in the Reference case, as a result of higher EUR per well and closer well spacing; tight oil development in Alaska; more offshore resources in Alaska and the lower 48 states; and more rapid technology improvements over the long term.

In the High Oil and Gas Resource case, higher well productivity reduces development and production costs per unit, resulting in more and earlier development of oil and gas resources than in the Reference case (Figure MT-52). U.S. crude oil production in the High Oil and Gas Resource case reaches 13.3 MMbbl/d in 2036, compared with an earlier and lower projected high point of 9.6 MMbbl/d in 2019 in the Reference case. Cumulative production in the High Oil and Gas Resource case is about 125 billion barrels—compared to about 90 billion barrels in the Reference case—from 2012 to 2040.

In the Low Oil and Gas Resource case, which assumes lower estimates of tight resources than in the Reference case, crude oil production plateaus at an earlier and lower projected high of 9.2 MMbbl/d in 2016 before declining. With production of tight oil continuing to decline through 2040 in the Low Oil and Gas Resource case, cumulative crude oil production from 2012 to 2040 is 10% lower than in the Reference case, at about 81 billion barrels.

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

Figure MT-53. Domestic crude oil production by source in the Reference case, 1990-2040 (million barrels per day)



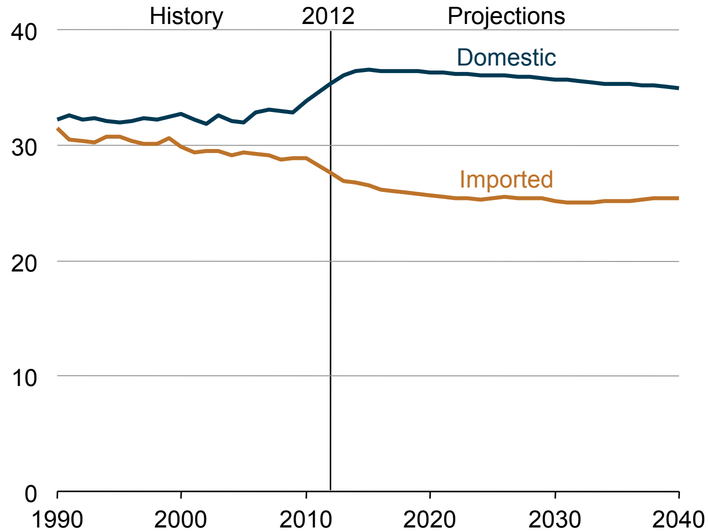
U.S. crude oil production grows from 2012 through 2019 in the Reference case, before peaking at more than 9.6 million barrels per day (MMbbl/d)—about 3.1 MMbbl/d above the 2012 total and close to the historical high of 9.6 MMbbl/d in 1970 (Figure MT-53). The growth in lower 48 onshore crude oil production is primarily a result of continued development of tight oil resources in the Bakken, Eagle Ford, and Permian Basin formations. Tight oil production increases to a peak of 4.8 MMbbl/d from 2018 through 2021 and then declines to about 3.2 MMbbl/d in 2040 (0.9 MMbbl/d higher than the 2012 total) as high-productivity areas, or sweet spots, are depleted. There is considerable uncertainty about the expected peak level of tight oil production, because ongoing exploration, appraisal, and development programs expand operator 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 after 2017—when oil prices rise, and as output from the more profitable tight oil deposits begins declining and affordable anthropogenic sources of carbon dioxide (CO_2) become available—to 0.7 MMbbl/d in 2040. The rate of the increase is slower over the last five years, when production is limited by reservoir quality and CO_2 availability. From 2013 through 2040, cumulative crude oil production from CO_2-EOR projects totals 5.2 billion barrels.

Lower 48 offshore oil production varies between 1.4 MMbbl/d and 2.0 MMbbl/d over the projection period. Toward the end of the period, 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 from the Alaska North Slope partially offsets the decline in production from onshore North Slope fields.

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

Figure MT-54. Average API gravity of U.S. domestic and imported crude oil supplies in the Reference case, 1990-2040 (degrees API)



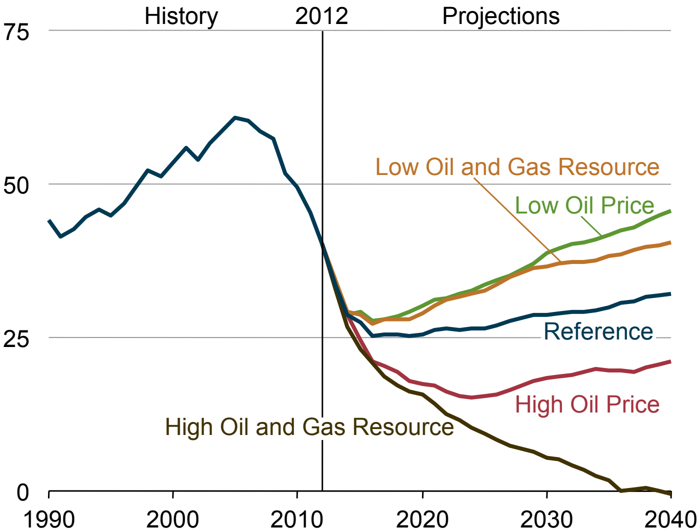
API gravity is a measure of the specific gravity, or relative density, of a liquid, as defined by the American Petroleum Institute. It is expressed in degrees, where a higher number indicates a lower density. Refineries generally process a mix of crude oils with a range of API gravities to optimize refinery operations. Over the past 15 years, the API gravity of crude oil processed in U.S. refineries has averaged between 30 and 32 degrees. As U.S. refiners run more domestic light crude oil produced from tight formations, they need less imported light crude to maintain an optimal API gravity. With increasing U.S. production of light crude oil in the AEO2014 Reference case, the average API gravity of crude oil imports declines from 27.6 degrees in 2012 to 25.6 degrees in 2040 (Figure MT-54).

With total crude oil imports declining in the Reference case, imports of light crude oil are reduced, resulting in a heavier slate of imported crude oil. The growing share of heavier crude oil imports continues through 2025 before stabilizing. The increase in demand for diesel fuel in the Reference case, from 3.4 MMbbl/d in 2012 to 4.3 MMbbl/d in 2040, combined with a steady increase in exports of distillate fuel oil from 1.0 MMbbl/d to 1.1 MMbbl/d over the same period, increases the value of heavier crudes in U.S. refineries.

The large increase in domestic production of light crude oil and the increase in imports of heavier crude oils have prompted significant investments in the midstream infrastructure for crude oil, including pipelines that will bring higher quantities of light sweet and heavy sour crudes to petroleum refineries along the U.S. Gulf Coast. In addition, significant investments have been made to move crude oil by rail to refineries on the East Coast, West Coast, and Gulf Coast.

Increasing U.S. oil supply reduces net imports of petroleum and other liquid fuels

Figure MT-55. Net import share of U.S. petroleum and other liquid fuels consumption in five cases, 1990-2040 (percent)



The net crude oil and product imports share of U.S. petroleum and other liquid fuels consumption grew from the mid-1980s to 2005 but has fallen steadily since 2005 (Figure MT-55). Because each barrel of U.S. crude oil production displaces a barrel of imported crude oil, the outlook for net petroleum and other liquid fuel imports in the High and Low Oil Price and High and Low Oil and Gas Resource cases depends on U.S. oil production.

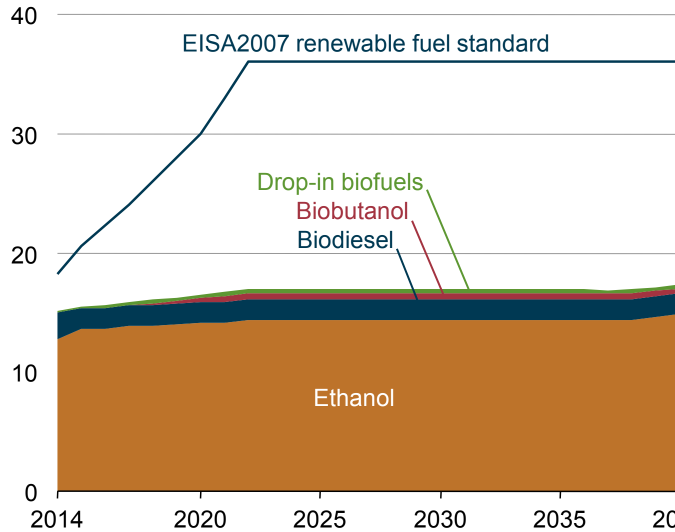
The net import share of U.S. petroleum and other liquid fuels consumption declines from 2012 through 2023 in the AEO2014 Reference case, largely because of projected growth in tight oil production. The net import share declines to 25% in 2019, coinciding with a peak in U.S. oil production of 9.6 MMbbl/d, then increases to 32% in 2040 after domestic oil production declines.

Higher oil prices encourage more rapid and extensive oil resource development. In the High Oil Price case, the share of domestic consumption accounted for by imports of petroleum and liquid fuels drops to 15% in 2023, then grows to 21% in 2040. The opposite occurs in the Low Oil Price case, with the petroleum and other liquids imports share of domestic consumption rising after 2016, to 46% in 2040.

In the High Oil and Gas Resource case, improvements in oil production technology beyond those in the Reference case, along with 1% annual growth in estimated ultimate recovery (EUR), lead to higher U.S. crude oil production. In 2036, U.S. crude production peaks at 13.3 MMbbl/d, and net U.S. imports of crude oil and petroleum products fall to virtually zero, where they remain through 2040. The Low Oil and Gas Resource case uses the same production technology assumptions as the Reference case but assumes a 50% lower EUR. As in the Low Price case, net imports begin to rise in 2016 and increase to 40% of U.S. consumption in 2040.

U.S. consumption of biofuels grows but does not approach EISA2007 applicable volumes

Figure MT-56. EISA2007 Renewable Fuels Standard credits earned by fuel type in the Reference case, 2012-40 (billion credits)



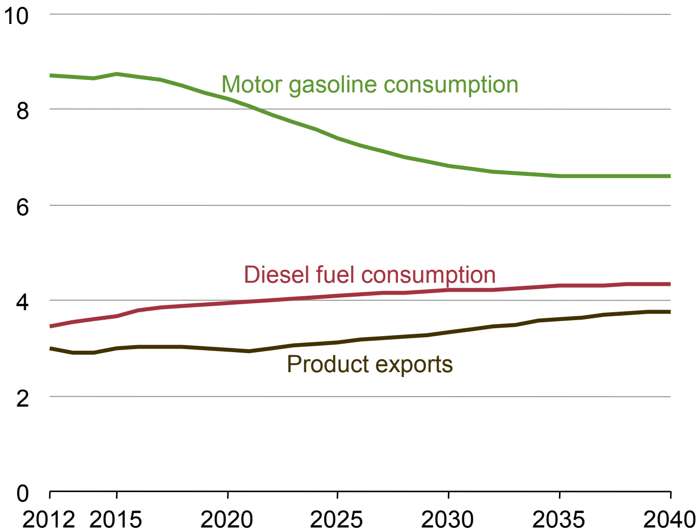
Consumption of biofuels grows in the AEO2014 Reference case but falls well short of the Energy Independence and Security Act of 2007 (EISA2007) RFS target [*13*] of 36 billion ethanol gallon equivalents in 2022 (Figure MT-56), largely because of a decline in gasoline consumption as a result of newly enacted corporate average fuel economy (CAFE) standards and updated expectations for sales of vehicles capable of using E85. Demand for motor gasoline ethanol blends (E10 and E15) falls from 8.7 MMbbl/d in 2012 to 7.9 MMbbl/d in 2022, while total biofuels consumption rises from 14 billion gallons to 16 billion ethanol gallons equivalent over the same period.

The current and projected vehicle fleets are not equipped to use ethanol's increased octane content relative to gasoline. As a result, the retail price of E85 must be less than 79% of the motor gasoline price for E85 to gain significant market share. In the Reference case, with the lowest ratio of E85 to gasoline prices at 77% in 2022, market penetration of E85 is modest, and the RFS program does not provide sufficient incentives to promote significant new ethanol production capacity.

In the Reference case, as gasoline demand continues to drop and E85 consumption levels off, total ethanol consumption grows to about 14 billion gallons in 2022 and remains there until late in the projection. Consumption of biodiesel falls in the near term, as production of drop-in biofuels grows. Domestic consumption of drop-in biofuels grows from 135 million ethanol gallons equivalent in 2014 to 316 million ethanol gallons equivalent in 2019. Biobutanol consumption rises after 2019, to about 516 million gallons in 2040.

A variety of factors leads to a shift in consumption from motor gasoline to diesel fuel

Figure MT-57. Motor gasoline consumption, diesel fuel consumption, and petroleum product exports in the Reference case, 2012-40 (million barrels per day)



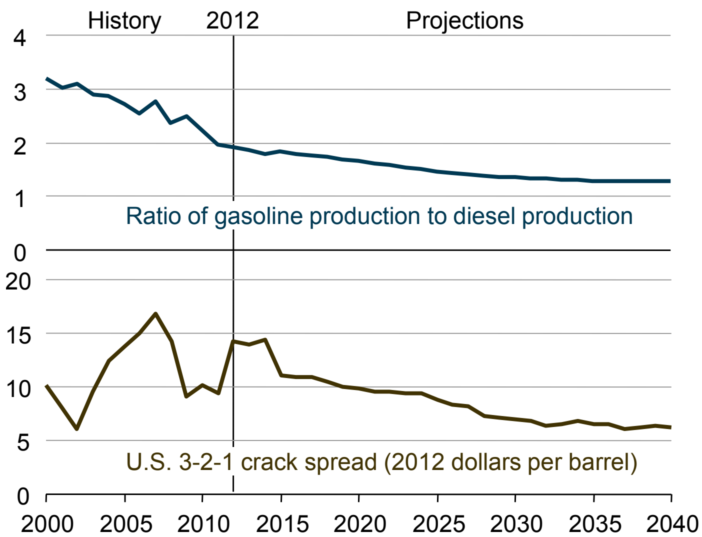
Based on the NHTSA and EPA GHG and CAFE standards, EIA projects that new light-duty vehicles (LDVs) will average approximately 47 mpg in 2025. These efficiency standards contribute to a decline in consumption of motor gasoline, while increases in vehicle miles traveled (VMT) and renewable fuel standards (RFS) lead to an increase in consumption of diesel fuel and ethanol in the Reference case. As a result of rising fuel economy standards, motor gasoline consumption by LDVs falls over the projection period while total VMT increase.

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, with consumption of diesel fuel increasing by approximately 0.9 MMbbl/d from 2012 to 2040, while finished motor gasoline consumption falls by 2.1 MMbbl/d (Figure MT-57). New refinery projects are expected to focus on shifting production from gasoline to distillate fuels to meet the growing demand for diesel.

As a result of refinery economics and slower growth in domestic demand, no new petroleum refinery crude unit capacity is built in the Reference case, except for plants already under construction in 2012. Further, the refining system has at least 2 MMbbl/d of excess crude oil capacity beginning in 2015. In addition to meeting domestic demand, refineries continue to export finished products to international markets throughout the projection. Beginning in 2016, gross exports of total finished petroleum products increase to 3.0 MMbbl/d for the first time, and in 2040 exceed 3.7 MMbbl/d (Figure MT-57). The United States became a net exporter of finished petroleum products in 2011, and in the Reference case, it remains a net exporter through 2040.

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

Figure MT-58. U.S. refinery gasoline-to-diesel production ratio and crack spread in the Reference case, 2000-40



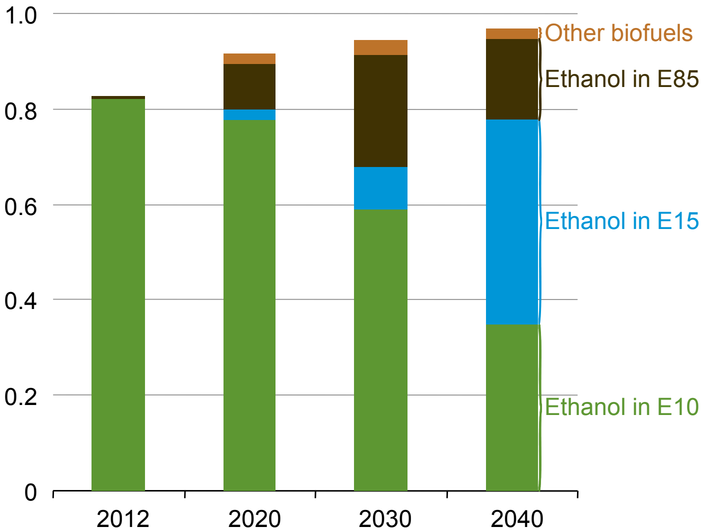
The transition to lower gasoline and higher diesel production has a significant effect on petroleum refinery operations in the AEO2014 Reference case, with the ratio of gasoline to diesel production declining from 1.8 in 2012 to below 1.3 in 2040 (Figure MT-58). In response to the drop in gasoline demand, refinery utilization of fluid catalytic cracking (FCC) units falls from 67% in 2012 to about 55% in 2040. In contrast, with diesel production increasing, installed distillate and gas oil hydrocracking capacity grows from about 2.2 MMbbl/d in 2012 to 2.9 MMbbl/d in 2040, indicating a shift from FCC feeds to hydrocrackers 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 finished products—typically, gasoline and distillate fuel. The 3-2-1 crack spread estimates the profitability of processing three barrels of crude oil to produce two barrels of gasoline and one barrel of distillate. In the Reference case, the 3-2-1 crack spread (based on Brent crude oil prices) declines from $14/barrel in 2012 to about $6/barrel in 2040 (2012 dollars). In the current environment, the gross margin would vary with the differential between Brent and Gulf Coast light crude oil prices.

To relate the gross margin to refinery profitability, operating costs for specific refineries also must be deducted. As product demands shift, petroleum refineries may alter the ratio of gasoline to diesel production. A 5-3-2 crack spread estimates the profitability of processing five barrels of crude oil into three barrels of gasoline and two barrels of distillate, more consistent with the 1.3 gasoline-to-diesel production ratio after 2035.

Consumption of biofuels blended into motor gasoline increases in response to RFS targets

Figure MT-59. Consumption of biofuels in motor gasoline blends in the Reference case, 2012-40 (million barrels per day)



In the AEO2014 Reference case, consumption of E15 motor gasoline (15% ethanol, 85% gasoline) and E85 motor gasoline (average 74% ethanol, 26% gasoline) increases at the expense of E10 motor gasoline (10% ethanol, 90% gasoline) (Figure MT-59). The shift depends on the level of RFS targets, infrastructure issues, the relative costs of E15 and biobutanol blends compared to E10 and E85, and the general market acceptability of manufacturers' automobile warranties.

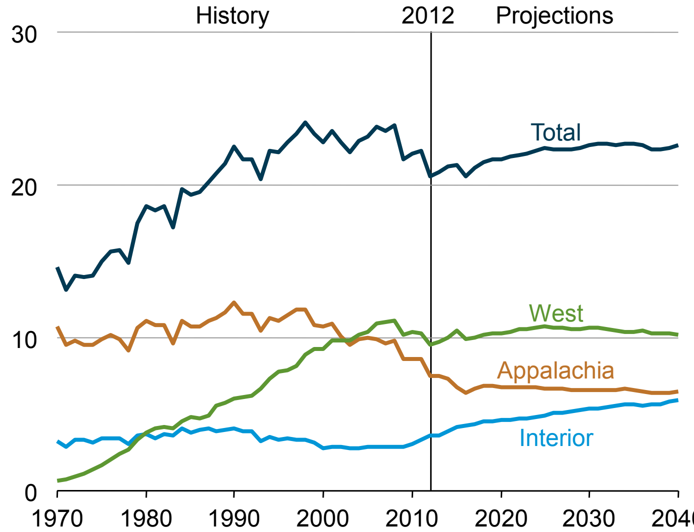
In response to RFS renewable fuel targets and market conditions, consumption of E15 increases in the Reference case, both in absolute terms and relative to E10 consumption. The growth of E15 consumption also displaces potential consumption of biobutanol blends, such as Bu16 (16% biobutanol, 84% gasoline).

Starting in about 2020, E15 slowly penetrates the motor gasoline market, as blend wall issues are assumed to be resolved over time [*14*]. In 2040, E15 makes up approximately 40% of the total motor gasoline market. Consumption of biobutanol-blended gasoline remains low, as it competes with E15 for market share. Although E85 is used in the motor gasoline market throughout the projection, its share of the market declines after 2032, when most cars are capable of using E15.

The increase in consumption of E15 in the Reference case is based on the assumption that consumers, refiners, and vehicle manufacturers will prefer E15 over E85 and biobutanol blends, and that infrastructure constraints will be resolved gradually over time. In addition to the biofuels blended into motor gasoline shown in Figure MT-59, the RFS also promotes consumption of other biofuels—such as biodiesel, renewable diesel, and renewable gasoline—that are not blended in fixed percentages with petroleum-based motor gasoline.

Coal production growth limited by competitive fuel prices and little new coal-fired capacity

Figure MT-60. Coal production by region in the Reference case, 1970-2040 (quadrillion Btu)



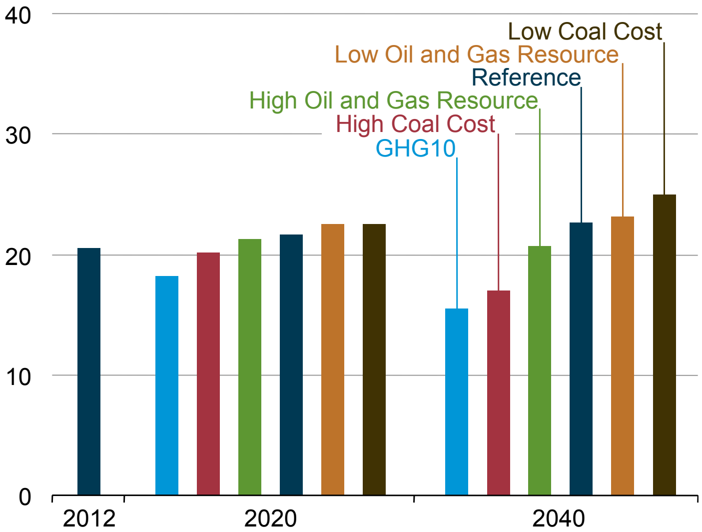
Coal production in 2012 was more than 7% below the 2011 total (Figure MT-60), mostly as a result of gas-on-coal competition. In the AEO2014 Reference case, coal production recovers briefly as natural gas prices rise before dropping to 2012 levels in 2016, as the need for electricity generators to comply with Mercury and Air Toxic Standards (MATS) leads to a wave of coal-fired capacity retirements. From 2016 to 2030, coal production increases gradually as growing electricity demand and rising natural gas prices spur the use of coal for power generation. After 2030, when existing coal units reach maximum utilization rates and virtually no new capacity is built, coal production stabilizes. Coal exports, which totaled 3.2 quadrillion Btu in 2012, remain at that level through 2020 and then increase to 3.8 quadrillion Btu in 2040. Overall, U.S. coal production grows by an average of 0.3%/year in the Reference case, from 20.6 quadrillion Btu in 2012 to 22.6 quadrillion Btu in 2040.

On a regional basis, strong production growth in the Interior region contrasts with generally stagnant production in Appalachia and the West. Interior coal production reaches new highs as scrubbers installed at existing coal-fired generating units allow them to burn the region's higher-sulfur coals with lower delivered costs. Western production grew steadily for decades but fell by 14% from 2008 to 2012 as a result of the recession and competition from natural gas. Western production increases slightly in the Reference case, tempered by slow growth in coal use for electricity generation and by competition from coal producers in the Interior region. Appalachian coal production declines by 14% from 2012 to 2016, as coal produced from the extensively mined, higher-cost reserves of Central Appalachia is supplanted by lower-cost coal from other regions.

Coal production

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

Figure MT-61. U.S. total coal production in six cases, 2012, 2020, and 2040 (quadrillion Btu)

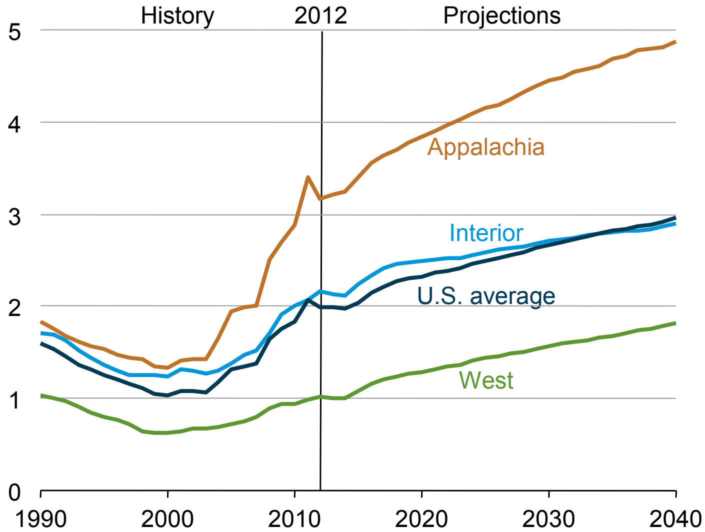


U.S. coal production varies across the AEO2014 cases, reflecting different assumptions about coal production and transportation costs, natural gas prices, and actions to limit greenhouse gas (GHG) emissions (Figure MT-61). In general, assumptions that reduce the competitiveness of coal versus natural gas lead to lower coal production. For example, relative to the Reference case, coal production is lower in both the High Coal Cost case (higher costs for coal mining and transportation) and the High Oil and Gas Resource case (lower costs for natural gas production). Similarly, actions to cut GHG emissions would also reduce the competeveness of coal because of its high carbon content. 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 MT-61, the GHG10 case shows the largest decline in U.S. coal production, with an economy-wide CO_2 emissions price that rises to $34 per metric ton of CO_2 (2012 dollars) in 2040, leading to 32% lower coal production in 2040 compared with the Reference case. Production in the High Coal Cost and Low Coal Cost cases is 7% lower and 4% higher, respectively, than in the Reference case in 2020, evolving to 25% lower and 11% higher in 2040 as the gap between coal and natural gas prices widens. In addition to the GHG10 case, two more GHG scenarios were developed for AEO2014 (not shown in Figure MT-61)—the GHG25 case, with an economywide CO_2 allowance fee that increases to $85 per metric ton in 2040; and the GHG10 and Low Gas Prices case, with lower natural gas prices than in the Reference case. In the GHG25 case and the GHG10 and Low Gas Prices case, total coal production in 2040 is 73% and 53% lower, respectively, than in the Reference case.

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

Figure MT-62. Average annual minemouth coal prices by region in the Reference case, 1990-2040 (2012 dollars per million Btu)



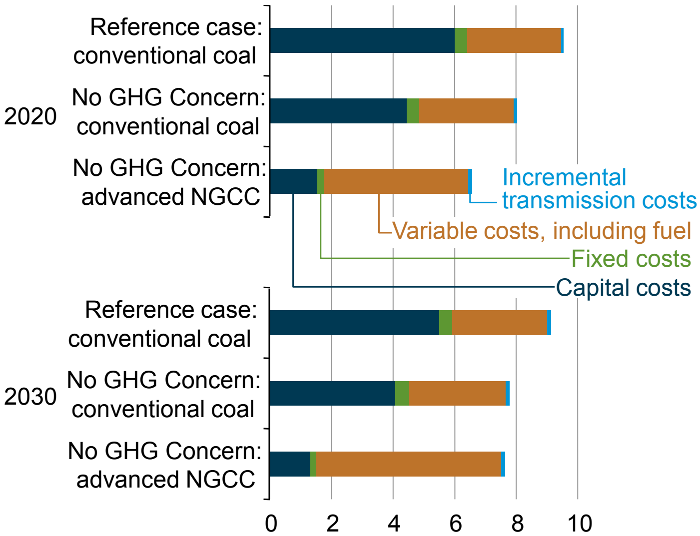
In the AEO2014 Reference case, the average real minemouth price for U.S. coal increases by 1.4%/year, from $1.98/MMBtu in 2012 to $2.96/MMBtu in 2040, continuing the upward trend that began in 2000 (Figure MT-62). A key factor underlying the higher coal prices is an expected decline in coal mining productivity in most areas, but at slower rates than those seen between 2000 and 2011. The minemouth price fell slightly in 2012, primarily as a result of a 19% decline in the price of coking coal [*15*]. Steam coal prices also declined in 2012, but by less than 1%. In the High and Low Coal Cost cases developed for AEO2014, different assumptions about mining productivity lead to minemouth coal prices in 2040 that are 87% higher and 45% lower, respectively, than in the Reference case.

In the Appalachia region, the average minemouth coal price increases by 1.6%/year from 2012 to 2040, because of a decline in mine productivity. The higher price outlook in the region also reflects a larger share of total production for higher-value coking coal, resulting from a decline in shipments of steam coal to domestic markets. Recent increases in the average price of Appalachia coal, from $1.33/MMBtu in 2000 to $3.16/MMBtu in 2012, have reduced the ability of Appalachia coal to compete with coal from other regions.

In the Western region, the coal price grows by 2.1%/year from 2012 to 2040. An increase in stripping ratios at mines in Wyoming's Powder River Basin, which contributed to a 32% decrease in the basin's coal mining productivity from 2000 to 2012, continues to push mining costs higher. In the Interior region, with a more optimistic outlook for mine productivity, minemouth prices rise by 1.0%/year from 2012 to 2040. Increased output from large, highly productive longwall mines in the region supports expected improvements in productivity.

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

Figure MT-63. Average levelized electricity costs for new coal and natural gas plants in two cases, 2020 and 2030 (2012 cents per kilowatthour)

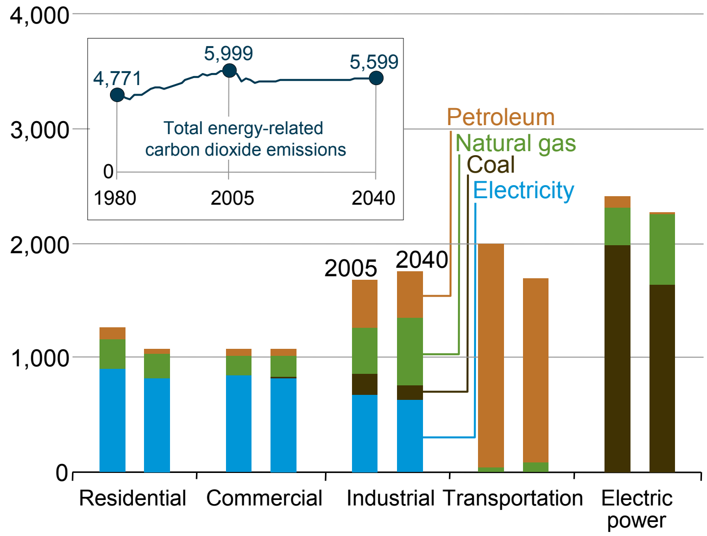


The cost of capital for investments in GHG-intensive technologies, such as new coal-fired and coal-to-liquids (CTL) plants without carbon capture and storage (CCS), is increased by 3 percentage points in the AEO2014 Reference case. This increase addresses the higher risk associated with those investments, given the potential for future restrictions on GHG emissions. The higher cost of capital is also applied to capital projects at existing coal-fired power plants (excluding CCS), such as retrofits to control emissions of mercury, acid gases, and particulates for compliance with MATS. The 3 percentage point adjustment is roughly equivalent in levelized cost terms to an emissions fee of $15/metric ton of CO_2 when investing in a new coal plant without CCS, and it increases the capital cost component for a new coal unit by approximately 1.5 cents/kWh. The No GHG Concern case assumes that the costs of capital for GHG-intensive technologies do not reflect the risk premium described above.

In the No GHG Concern case, estimated levelized costs for new coal- and natural gas-fired capacity begin to converge in the mid- to late-2020s (Figure MT-63) [*16*], leading to new coal-fired capacity builds in a number of regions. In comparison, virtually no new unplanned coal-fired capacity is added in the Reference case until nearly 2040. In the No GHG Concern case, 13 GW of new coal-fired capacity is added (including plants currently under construction), compared with fewer than 3 GW in the Reference case. As a consequence, additions of natural gas, nuclear, and renewable generating capacity all are slightly lower in the No GHG Concern case than in the Reference case, and total energy-related CO_2 emissions in 2040 are 54 million metric tons (1%) higher than in the Reference case. In the No GHG Concern case, the cost estimates for new coal-fired plants by region in 2030 range from 9% below to 11% above the national average—not including New England, where the cost estimate is 23% above the national average [*17*].

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

Figure MT-64. U.S. energy-related carbon dioxide emissions by sector and fuel in the Reference case, 2005 and 2040 (million metric tons)



Energy-related CO_2 emissions in the AEO2014 Reference case decline by 0.2%/year on average from 2005 to 2040, as compared with an average increase of 0.9%/year from 1980 to 2005. Reasons for the decline include lower economic growth, increasing 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 when combusted. Energy-related CO_2 emissions in 2020 are 8.7% below their 2005 level in the Reference case, and in 2040 they total 5,599 million metric tons (MMmt) and 400 MMmt (6.7%) below their 2005 level (Figure MT-64).

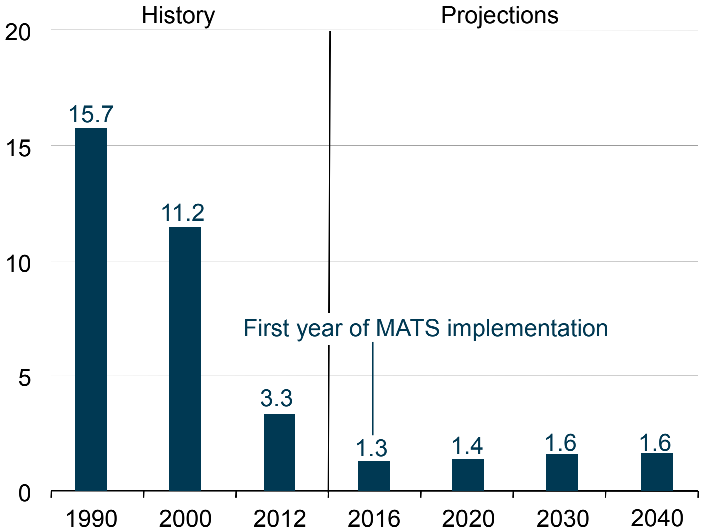
In the Reference case, petroleum remains the largest source of U.S. energy-related CO_2 emissions. However, its share of the total falls to 38% in 2040 from 44% in 2005. In 2040, CO_2 emissions from petroleum use, mainly in the transportation sector, are 509 MMmt below the 2005 level.

Emissions from coal, the second-largest source of energy-related CO_2 emissions, are 402 MMmt below the 2005 level in 2040 in the Reference case, and their share of total energy-related CO_2 emissions declines from 36% in 2005 to 32% in 2040. The natural gas share of energy-related CO_2 emissions increases from 20% in 2005 to 30% 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 AEO2014.

Emissions from energy use

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

Figure MT-65. Sulfur dioxide emissions from electricity generation in selected years in the Reference case, 1990-2040 (million short tons)



In the AEO2014 Reference case, sulfur dioxide (SO_2) emissions from the electric power sector increase slightly in the early years of the projection but fall rapidly in 2016, when the Mercury and Air Toxics Standards (MATS) [*18*] are fully implemented.

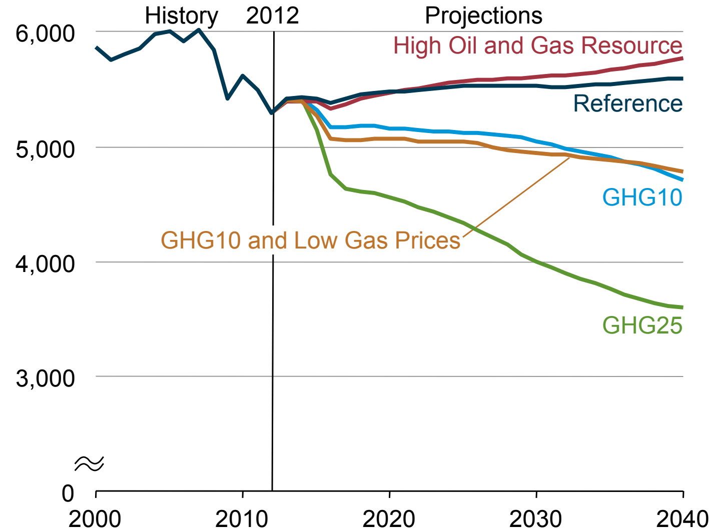
The Reference case assumes that all coal-fired power plants operating in the United States will be equipped with either flue gas desulfurization units (scrubbers) or dry sorbent injection (DSI) systems by 2016 to comply with the specific requirements of MATS. The emissions controls have the ancillary benefit of removing significant amounts of SO_2. For example, scrubbers remove more than 90% of SO_2 emissions from flue gas. DSI systems, when combined with fabric filters, remove approximately 70% of SO_2 emissions.

At the end of 2012, 64% of electric power sector coal-fired generating capacity in the United States already had either scrubbers or DSI systems installed. The Reference case assumes that by 2016, every operating coal plant in the United States larger than 25 megawatts has some type of control equipment, including approximately 31 GW of coal-fired capacity retrofitted with scrubbers and another 45 GW retrofitted with DSI systems.

After a 61% decrease from 2012 to 2016 (Figure MT-65), annual SO_2 emissions increase by 0.9%/year from 2016 to 2040, as total electricity generation from coal-fired power plants increases by 0.3%/year, and scrubbers and DSI equipment remove most (but not all) SO_2 from flue gas. As a result of MATS compliance, SO_2 emissions are reduced to a level below the cap specified in the Clean Air Interstate Rule (CAIR).

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

Figure MT-66. Energy-related carbon dioxide emissions in five cases, 2000-40 (million metric tons)



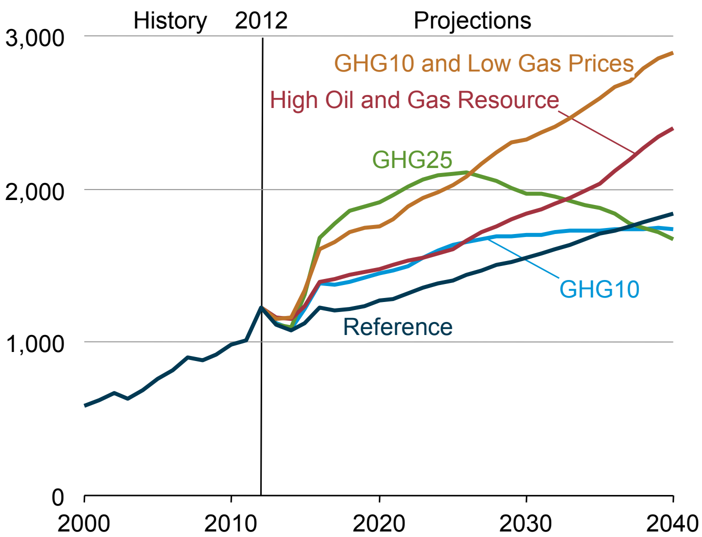
Although the AEO2014 Reference case assumes that current laws and regulations remain in effect through 2040, the potential impacts of future policies that would place an implicit or explicit value on CO_2 emissions are examined in two cases, starting at $10 (GHG10) and $25 (GHG25) per metric ton CO_2 in 2015 and rising by 5% per year thereafter. 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, the $10 fee case was run both with the Reference case and combined with the High Oil and Gas Resource case (GHG10 and Low Gas Prices) (Figure MT-66).

Emissions fees or other policies that place an explicit or implicit value on CO_2 emissions 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 15% and 28% lower in 2025 in the GHG10 and GHG25 cases using Reference case resources, respectively, and 22% and 40% lower in 2040. When combined with High Oil and Gas Resource assumptions, the CO_2 fees in the GHG10 case 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 the GHG10 and Low Gas Prices case. 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. Shortly after 2020, 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 fees first favor, then discourage, natural gas-fired generation

Figure MT-67. Natural gas-fired electricity generation in five cases, 2000-40 (billion kilowatthours)



The role of natural gas in the CO_2 fee cases varies widely over time and also varies over the range of assumptions about natural gas resources. When CO_2 fees are assumed to be introduced in 2015 in both the GHG10 and GHG25 cases, natural gas-fired generation increases sharply during the first few years, and it continues to increase modestly over the next several years (Figure MT-67). Subsequently, the increases no longer occur, as more new nuclear and renewable plants are added. In the GHG10 case, natural gas-fired generation levels off around 2030. In the GHG25 case, the role of natural gas begins to decline after 2025.

After accounting for about 50% of all U.S. electricity generation for many years, coal's share has declined in recent years as a result of growing competition from efficient natural gas-fired plants with access to relatively low-cost natural gas. In the Reference case, the share of generation fueled by coal falls from 37% in 2012 to 32% in 2040. Coal's share falls even further in the GHG cases, to a range between 10% and 28% in 2025 and between 1% and 19% in 2040.

As the fee for CO_2 emissions increases over time, power companies reduce their use of coal and increase their use of natural gas, renewables, and nuclear. The nuclear and renewable shares of total generation increase in most of the GHG cases, particularly in the later years of the projections. In the Reference case, nuclear generation accounts for 17% of the total in 2025 and 16% in 2040. In the GHG cases, the nuclear share varies from 17% to 21% in 2025 and from 17% to 37% in 2040. In the Reference case, the renewable share of total generation increases from 15% in 2025 to 16% in 2040. The renewable share is generally higher in the GHG cases—between 17% and 20% in 2025 and between 18% and 27% in 2040.

Endnotes for Market trends

Links current as of April 2014

1. 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.
2. Value of shipments includes both final and intermediate products.
3. S.C. Davis, S.W. Diegel, and R.G. Boundy, *Transportation Energy Databook: Edition 32,* ORNL-6989 (Oak Ridge, TN: July 2013), Chapter 2, Table 2.1, "U.S. Consumption of Total Energy by End-Use Sector, 1973-2012."
4. S.C. Davis, S.W. Diegel, and R.G. Boundy, *Transportation Energy Databook: Edition 32,* ORNL-6989 (Oak Ridge, TN: July 2013), Chapter 4, Table 4.6, "New Retail Sales of Trucks 10,000 Pounds GVWR and Less in the United States, 1970-2012."
5. U.S. Environmental Protection Agency and National High way 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.
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; 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.
7. LDV fuel economy includes alternative-fuel vehicles and banked credits towards compliance.
8. Factors that influence decisionmaking on capacity additions include electricity demand growth, the need to replace inefficient plants, the costs and operating efficiencies of different power generation options, fuel prices, state RPS programs, and the availability of federal tax credits for some technologies.
9. Unless otherwise noted, the term capacity in the discussion of electricity generation indicates utility, nonutility, and CHP capacity.
10. Costs are for the electric power sector only.
11. 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 2014," http://www.eia.gov/forecasts/aeo/electricity_generation.cfm.
12. HGL is a new term that accounts for similar fuels produced from both natural gas and petroleum through different processes. A description of the term HGL and how related terms are applied can be found at http://www.eia.gov/ngl/.
13. 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.
14. U.S. Energy Information Administration, *This Week in Petroleum* (November 23, 2011), http://www.eia.gov/oog/info/twip/twiparch/2011/111123/twipprint.html.
15. Minemouth coal price estimates for coking coal (or premium metallurgical) and steam coal in 2012 dollars/short ton are provided in the AEO2014 Reference case "Supplemental Tables for Regional Detail," Table 140. These prices are converted to units of 2012 dollars/million Btu by using the production and price data from AEO2014 Supplemental Data Tables 139 and 140, the heat content data for total coal production from Supplemental Data Table 146, and an estimated heat content of 26.3 million Btu/short ton for U.S. coking coal production. For regional detail, see the AEO2014 Reference case "Supplemental Tables for Regional Detail," http://www.eia.gov/forecasts/aeo/tables_ref.cfm.
16. For detailed discussion of levelized costs, see U.S. Energy Information Administration, "Levelized Cost and Levelized Avoided Cost of New Generation Resources in the Annual Energy Outlook 2014," http://www.eia.gov/forecasts/aeo/electricity_generation.cfm.
17. The levelized cost estimates shown in Figure MT-63 represent national averages.
18. U.S. Environmental Protection Agency, "Mercury and Air Toxics Standards," http://www.epa.gov/mats.

Figure and table sources

Links current as of April 2014

Figure MT-1. Average annual growth rates of real GDP, labor force, and productivity in three cases, 2012-40: Projections: AEO2014 National Energy Modeling System, runs REF2014.D102413A, LOWMACRO.D112913A, and HIGHMACRO.D112913A.

Figure MT-2. Average annual growth rates for real output and its major components in three cases, 2012-40: History: Bureau of Economic Analysis. **Projections:** AEO2014 National Energy Modeling System, runs REF2014.D102413A, LOWMACRO.D112913A, and HIGHMACRO.D112913A.

Figure MT-3. Annual growth rates of shipments for the industrial sector and its components in three cases, 2012-40: Projections: AEO2014 National Energy Modeling System, runs REF2014.D102413A, LOWMACRO.D112913A, and HIGHMACRO.D112913A.

Figure MT-4. North Sea 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:** AEO2014 National Energy Modeling System, runs REF2014.D102413A, LOWPRICE.D120613A, and HIGHPRICE.D120613A.

Figure MT-5. World petroleum and other liquids consumption by region in three cases, 2012 and 2040: Projections: AEO2014 National Energy Modeling System, runs REF2014.D102413A LOWPRICE.D120613A, and HIGHPRICE.D120613A.

Figure MT-6. World production of nonpetroleum liquids by type, 2012 and 2040: Projections: AEO2014 National Energy Modeling System, run REF2014.D102413A.

Figure MT-7. Energy use per capita and per dollar of gross domestic product in the Reference case, 1980-2040: History: U.S. Energy Information Administration, *Monthly Energy Review,* September 2013, DOE/EIA-0035(2013/09). **Projections:** AEO2014 National Energy Modeling System, run REF2014.D102413A.

Figure MT-8. Primary energy use by end-use sector in selected years in the Reference case, 2012-40: History: U.S. Energy Information Administration, *Monthly Energy Review,* September 2013, DOE/EIA-0035(2013/09). **Projections:** AEO2014 National Energy Modeling System, run REF2014.D102413A.

Figure MT-9. Primary energy use by fuel in the Reference case, 1980-2040: History: U.S. Energy Information Administration, *Monthly Energy Review,* September 2013, DOE/EIA-0035(2013/09). **Projections:** AEO2014 National Energy Modeling System, run REF2014.D102413A.

Figure MT-10. Residential delivered energy intensity in four cases, 2009-40: History: U.S. Energy Information Administration, *Monthly Energy Review,* September 2013, DOE/EIA-0035(2013/09). **Projections:** AEO2014 National Energy Modeling System, runs REF2014.D102413A, FROZTECH.D121813A, HIGHTECH.D121813A, and BESTTECH.D121813A.

Figure MT-11. Change in residential electricity consumption for selected end uses in the Reference case, 2012-40: Projections: AEO2014 National Energy Modeling System, run REF2014.D102413A.

Figure MT-12. Residential electricity sales in two cases, 1980-2040: History: U.S. Energy Information Administration, *Monthly Energy Review,* September 2013, DOE/EIA-0035(2013/09). **Projections:** AEO2014 National Energy Modeling System, run REF2014.D102413A and EXTENDED.D022814A.

Figure MT-13. Residential distributed generation in three cases, 2012-40: Projections: AEO2014 National Energy Modeling System, run REF2014.D102413A, NOSUNSET.D121713A, and LCR_2014.D120613A.

Figure MT-14. Commercial delivered energy intensity in four cases, 2005-40: History: U.S. Energy Information Administration, *Monthly Energy Review,* September 2013, DOE/EIA-0035(2013/09). **Projections:** AEO2014 National Energy Modeling System, runs REF2014.D102413A, FROZTECH.D121813A, HIGHTECH.D121813A, and BESTTECH.D121813A.

Figure MT-15. Energy intensity of selected commercial end uses in the Reference case, 2012 and 2040: Projections: AEO2014 National Energy Modeling System, run REF2014.D102413A.

Figure MT-16. Efficiency gains for selected commercial equipment in three cases, 2040: Projections: AEO2014 National Energy Modeling System, runs REF2014.D102413A, FROZTECH.D121813A, and BESTTECH.D121813A.

Figure MT-17. Additions to electricity generation capacity in the commercial sector in two cases, 2012-40: Projections: AEO2014 National Energy Modeling System, runs REF2014.D102413A and NOSUNSET.D121713A.

Figure MT-18. Industrial delivered energy consumption by application in the Reference case, 2012-40: Projections: AEO2014 National Energy Modeling System, run REF2014.D102413A.

Figure MT-19. Industrial energy consumption by fuel in the Reference case, 2012-40: Projections: AEO2014 National Energy Modeling System, run REF2014.D102413A.

Figure MT-20. Change in liquid feedstock consumption in three cases, 2012-40: Projections: AEO2014 National Energy Modeling System, runs REF2014.D102413A, LOWRESOURCE.D112913A, and HIGHRESOURCE.D112913B.

Figure MT-21. Heat and power consumption for refining and manufacturing applications in three cases, 2012, 2025, and 2040: Projections: AEO2014 National Energy Modeling System, runs REF2014.D102413A, LOWMACRO.D112913A, and HIGHMACRO.D112913A.

Figure MT-22. Cumulative growth in energy consumption by metal-based durables industries, 2012-40: Projections: AEO2014 National Energy Modeling System, runs REF2014.D102413A, LOWMACRO.D112913A, and HIGHMACRO.D112913A.

Figure MT-23. Delivered energy consumption by nonmanufacturing industries in three cases, 2012 and 2040: Projections: AEO2014 National Energy Modeling System, run REF2014.D102413A, LOWMACRO.D112913A, and HIGHMACRO.D112913A.

Figure MT-24. Delivered energy consumption for transportation by mode in the Reference case, 2012 and 2040: Projections: AEO2014 National Energy Modeling System, run REF2014.D102413A.

Figure MT-25. Average fuel economy of new light-duty vehicles in the Reference case, 1980-2040: History: U.S. Department of Transportation, National Highway Traffic Safety Administration, *Summary of Fuel Economy Performance,* April 2013. www.nhtsa.gov/staticfiles/rulemaking/pdf/cafe/April_2013_Summary_Report.pdf. **Projections:** AEO2014 National Energy Modeling System, run REF2014.D102413A.

Figure MT-26. Vehicle miles traveled per licensed driver in the Reference case, 1970-2040: History: U.S. Department of Transportation, Federal Highway Administration, *Highway Statistics 2011* (Washington, DC: 2013), http://www.fhwa.dot.gov/policyinformation/statistics/2011/. **Projections:** AEO2014 National Energy Modeling System, run REF2014.D102413A.

Figure MT-27. Sales of light-duty vehicles using non-gasoline technologies by type in the Reference case, 2012, 2025, and 2040: Projections: AEO2014 National Energy Modeling System, run REF2014.D102413A.

Figure MT-28. Natural gas consumption in the transportation sector in the Reference case, 1995-2040: AEO2014 National Energy Modeling System, run REF2014.D102413A.

Figure MT-29. U.S. electricity demand growth in the Reference case, 1950-2040: History: U.S. Energy Information Administration, *Monthly Energy Review,* September 2013, DOE/EIA-0035(2013/09). **Projections:** AEO2014 National Energy Modeling System, run REF2014.D102413A.

Figure MT-30. Electricity generation by fuel in the Reference case, 1990-2040: Projections: AEO2014 National Energy Modeling System, run REF2014.D102413A.

Figure MT-31. Electricity generation capacity additions by fuel type, including combined heat and power, in the Reference case, 2013-40: Projections: AEO2014 National Energy Modeling System, run REF2014.D102413A.

Figure MT-32. Additions to electricity generating capacity in the Reference case, 1985-2040: History: Energy Information Administration, Form EIA-860, "Annual Electric Generator Report." **Projections:** AEO2014 National Energy Modeling System, run REF2014.D102413A.

Figure MT-33. Electricity sales and power sector generating capacity in the Reference case, 1949-2040: History: U.S. Energy Information Administration, *Monthly Energy Review,* September 2013, DOE/EIA-0035(2013/09). **Projections:** AEO2014 National Energy Modeling System, run REF2014.D102413A.

Figure MT-34. Levelized electricity costs for new power plants, excluding subsidies, 2020 and 2040: Projections: AEO2014 National Energy Modeling System, run REF2014.D102413A.

Figure MT-35. Nuclear electricity generation in four cases, 1995-2040: History: U.S. Energy Information Administration, *Monthly Energy Review,* September 2013, DOE/EIA-0035(2013/09). **Projections:** AEO2014 National Energy Modeling System, runs REF2014.D102413A, ALTLOWNUC14.D012314C, HINUC14.D120313A, and LOWNUC14.D012314B.

Figure MT-36. Renewable electricity generation capacity by energy source, including end-use capacity, 2012-40: Projections: AEO2014 National Energy Modeling System, run REF2014.D102413A.

Figure MT-37. Renewable electricity generation by type, all sectors, in the Reference case, 2000-40: History: U.S. Energy Information Administration, *Monthly Energy Review,* September 2013, DOE/EIA-0035(2013/09). **Projections:** AEO2014 National Energy Modeling System, run REF2014.D102413A.

Figure MT-38. Regional nonhydropower renewable electricity, including end-use generation, in the Reference case, 2012 and 2040: Projections: AEO2014 National Energy Modeling System, run REF2014.D102413A.

Figure MT-39. Natural gas consumption by sector in the Reference case, 1990-2040: History: U.S. Energy Information Administration, *Monthly Energy Review,* September 2013, DOE/EIA-0035(2013/09). **Projections:** AEO2014 National Energy Modeling System, run REF2014.D102413A.

Figure MT-40. Annual average Henry Hub spot natural gas prices in the Reference case, 1990-2040: History: U.S. Energy Information Administration, *Natural Gas Annual 2012,* DOE/EIA-0131(2012) (Washington, DC, December 2013). **Projections:** AEO2014 National Energy Modeling System, run REF2014.D102413A.

Figure MT-41. Annual average Henry Hub spot prices for natural gas in five cases, 1990-2040: History: U.S. Energy Information Administration, *Natural Gas Annual 2012,* DOE/EIA-0131(2012) (Washington, DC, December 2013). **Projections:** AEO2014 National Energy Modeling System, runs REF2014.D102413A, LOWMACRO.D112913A, HIGHMACRO.D112913A, LOWRESOURCE.D112913A, and HIGHRESOURCE.D112913B.

Figure MT-42. Total U.S. natural gas production, consumption, and imports in the Reference case, 1990-2040: History: U.S. Energy Information Administration, *Natural Gas Annual 2012,* DOE/EIA-0131(2012) (Washington, DC, December 2013). **Projections:** AEO2014 National Energy Modeling System, run REF2014.D102413A.

Figure MT-43. Total U.S. natural gas production in three oil price cases, 1990-2040: History: U.S. Energy Information Administration, *Natural Gas Annual 2012,* DOE/EIA-0131(2012) (Washington, DC, December 2013). **Projections:** AEO2014 National Energy Modeling System, runs REF2014.D102413A, LOWPRICE.D120613A, and HIGHPRICE.D120613A.

Figure MT-44. Natural gas production by source in the Reference case, 1990-2040: History: U.S. Energy Information Administration, *Natural Gas Annual 2012,* DOE/EIA-0131(2012) (Washington, DC, December 2013). **Projections:** AEO2014 National Energy Modeling System, run REF2014.D102413A.

Figure MT-45. U.S. net imports of natural gas by source in the Reference case, 1990-2040: History: U.S. Energy Information Administration, *Natural Gas Annual 2011,* DOE/EIA-0131(2011) (Washington, DC, January 2013). **Projections:** AEO2014 National Energy Modeling System, run REF2014.D102413A.

Figure MT-46. U.S. exports of liquefied natural gas in five cases, 2005-40: History: U.S. Energy Information Administration, *Monthly Energy Review,* September 2013, DOE/EIA-0035(2013/09). **Projections:** AEO2014 National Energy Modeling System, runs REF2014.D102413A, LOWRESOURCE.D112913A, HIGHRESOURCE.D112913B, LOWPRICE.D120613A, and HIGHPRICE.D120613A.

Figure MT-47. U.S. natural gas production in three cases, 1990-2040: History: U.S. Energy Information Administration, *Monthly Energy Review,* September 2013, DOE/EIA-0035(2013/09). **Projections:** AEO2014 National Energy Modeling System, runs REF2014.D102413A, LOWRESOURCE.D112913A, and HIGHRESOURCE.D112913B.

Figure MT-48. Marcellus shale production share of total U.S. natural gas consumption east of the Mississippi River in the Reference case, 2000-40: History: U.S. Energy Information Administration, *Monthly Energy Review,* September 2013, DOE/EIA-0035(2013/09). **Projections:** AEO2014 National Energy Modeling System, run REF2014.D102413A.

Figure MT-49. Natural gas-fired electricity generation by NERC region in the Reference case, 2005-40: History: U.S. Energy Information Administration, *Monthly Energy Review,* September 2013, DOE/EIA-0035(2013/09). **Projections:** AEO2014 National Energy Modeling System, run REF2014.D102413A.

Figure MT-50. Consumption of petroleum and other liquids by sector in the Reference case, 1990-2040: History: U.S. Energy Information Administration, *Monthly Energy Review,* September 2013, DOE/EIA-0035(2013/09). **Projections:** AEO2014 National Energy Modeling System, run REF2014.D102413A.

Figure MT-51. U.S. production of petroleum and other liquids by source in the Reference case, 2012-40: Projections: AEO2014 National Energy Modeling System, run REF2014.D102413A.

Figure MT-52. Total U.S. crude oil production in three cases, 1990-2040: History: U.S. Energy Information Administration, *Monthly Energy Review,* September 2013, DOE/EIA-0035(2013/09). **Projections:** AEO2014 National Energy Modeling System, runs REF2014.D102413A, LOWRESOURCE.D112913A, and HIGHRESOURCE.D112913B.

Figure MT-53. Domestic crude oil production by source in the Reference case, 1990-2040: History: U.S. Energy Information Administration, *Monthly Energy Review,* September 2013, DOE/EIA-0035(2013/09). **Projections:** AEO2014 National Energy Modeling System, run REF2014.D102413A.

Figure MT-54. Average API gravity of U.S. domestic and imported crude oil supplies in the Reference case, 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:** AEO2014 National Energy Modeling System, run REF2014.D102413A.

Figure MT-55. Net import share of U.S. petroleum and other liquids consumption in five cases, 1990-2040: History: U.S. Energy Information Administration, *Monthly Energy Review,* September 2013, DOE/EIA-0035(2013/09). **Projections:** AEO2014 National Energy Modeling System, runs REF2014.D102413A, LOWRESOURCE.D112913A, HIGHRESOURCE.D112913B, LOWPRICE.D120613A, and HIGHPRICE.D120613A.

Figure MT-56. EISA2007 Renewable Fuels Standard credits earned by fuel type in the Reference case, 2012-40: Projections: AEO2014 National Energy Modeling System, run REF2014.D102413A.

Figure MT-57. Motor gasoline consumption, diesel fuel consumption, and petroleum product exports in the Reference case, 2012-40: History: U.S. Energy Information Administration, *Monthly Energy Review,* September 2013, DOE/EIA-0035(2013/09). **Projections:** AEO2014 National Energy Modeling System, run REF2014.D102413A.

Figure MT-58. U.S. refinery gasoline-to-diesel production ratio and crack spread in the Reference case, 2000-40: History: Crack spread calculated from national average New York Harbor (NYH) RBOB prices and ULSD spot prices (2006-12) and No. 2 heating oil spot prices (2000-05), http://www.eia.gov/dnav/pet/pet_pri_spt_s1_d.htm. **2000-12:** Gasoline and diesel refinery production calculated from finished gasoline, motor gasoline blend components (net), and distillate fuel oil (15ppm and 15-500 ppm), http://www.eia.gov/dnav/pet/pet_pnp_refp2_dc_nus_mbblpd_a.htm and http://www.eia.gov/dnav/pet/pet_pnp_intp2_dc_nus_mbblpd_a.htm. **Projections:** AEO2014 National Energy Modeling System, run REF2014.D102413A.

Figure MT-59. Consumption of biofuels in motor gasoline blends in the Reference case, 2012-40: History: U.S. Energy Information Administration, *Monthly Energy Review,* September 2013, DOE/EIA-0035(2013/09). **Projections:** AEO2014 National Energy Modeling System, run REF2014.D102413A.

Figure MT-60. Coal production by region in the Reference case, 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). **2001-2012:** U.S. Energy Information Administration, *Annual Coal Report 2012,* DOE/EIA-0584(2012) (Washington, DC, December 2013), and previous issues. **History (conversion to quadrillion Btu): 1970-2012:** 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 *Monthly Energy Review.* **Sources:** U.S. Energy Information Administration, *Monthly Energy Review,* September 2013, DOE/EIA-0035(2013/09), 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, "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:** AEO2014 National Energy Modeling System, run REF2014.D102413A. Note: For 1989-2040, coal production includes waste coal.

Figure MT-61. U.S. total coal production in six cases, 2012, 2020, and 2040: Projections: AEO2014 National Energy Modeling System, runs REF2014.D102413A, LCCST14.D120413A, HCCST14.D120413A, LOWRESOURCE.D112913A, HIGHRESOURCE.D112913B, and CO2FEE10.D011614A. Note: Coal production includes waste coal.

Figure MT-62. Average annual minemouth coal prices by region in the Reference case, 1990-2040: History (dollars per short ton): 1990-2000: U.S. Energy Information Administration, *Coal Industry Annual,* DOE/EIA-0584 (various years). **2001-2012:** U.S. Energy Information Administration, *Annual Coal Report 2012,* DOE/EIA-0584(2012) (Washington, DC, December 2013), and previous issues. **History (conversion to dollars per million Btu): 1970-2012:** 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 *Monthly Energy Review.* **Sources:** U.S. Energy Information Administration, *Monthly Energy Review,* DOE/EIA-0035(2013/09) (Washington, DC, September 2013), 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, "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:** AEO2014 National Energy Modeling System, run REF2014.D102413A. Note: Includes reported prices for both open-market and captive mines.

Figure MT-63.Average levelized electricity costs for new coal and natural gas plants in two cases, 2020 and 2030: Projections: AEO2014 National Energy Modeling System, runs REF2014.D102413A and NOGHGCONCERN.D120413A. Note: Costs for conventional coal reflect estimates for a supercritical pulverized coal plant that includes all advanced control technologies except for CCS. NGCC represents natural gas combined-cycle.

Figure MT-64. U.S. energy-related carbon dioxide emissions by sector and fuel in the Reference case, 2005 and 2040: History: U.S. Energy Information Administration, Monthly Energy Review, September 2013, DOE/EIA-0035(2013/09). **Projections:** AEO2014 National Energy Modeling System, run REF2014.D102413A.

Figure MT-65. Sulfur dioxide emissions from electricity generation in the Reference case, 1990-2040: History: U.S. Environmental Protection Agency, Clean Air Markets Database, http://ampd.epa.gov/ampd/. **Projections:** AEO2014 National Energy Modeling System, run REF2014.D102413A.

Figure MT-66. Energy-related carbon dioxide emissions in five cases, 2000-40: History: U.S. Energy Information Administration, *Monthly Energy Review,* September 2013, DOE/EIA-0035(2013/09). **Projections:** AEO2014 National Energy Modeling System, runs REF2014.D102413A, HIGHRESOURCE.D112913B, CO2FEE10.D011614A, CO2FEE25.D011614A, and CO2FEE10HR.D011614A.

Figure MT-67. Natural gas-fired electricity generation in five cases, 2000-40: History: U.S. Energy Information Administration, *Monthly Energy Review,* September 2013, DOE/EIA-0035(2013/09). **Projections:** AEO2014 National Energy Modeling System, runs REF2014.D102413A, HIGHRESOURCE.D112913B, CO2FEE10.D011614A, CO2FEE25.D011614A, and CO2FEE10HR.D011614A.

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.

IHS Global Insight (IHSGI) is the only organization available to the U.S. Energy Information Administration (EIA) that produces an energy projection with detail and a time horizon that are comparable to those in the *Annual Energy Outlook 2014* (AEO2014). 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 AEO2014 Reference case.

CP1. Economic growth

The range of projected economic growth in the outlooks included in the comparison tends to be wider over the first three 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 2012 to 2015 ranges from 2.4% to 3.0% (Table CP1); while the 13-year annual average growth, from 2012 to 2025, ranges from 2.5% to 2.8%.

From 2012 to 2015, real GDP grows at a 2.6% average annual rate in the AEO2014 Reference case, lower than projected by the Office of Management and Budget (OMB), the Social Security Administration (SSA) (in *The 2013 Annual Report of the Board of Trustees of the Federal Old-Age and Survivors Insurance and Federal Disability Insurance Trust Funds*), and Oxford Economic Group (OEG), but higher than that projected by Interindustry Forecasting Project at the University of Maryland (INFORUM). The AEO2014 projection of GDP growth is similar to the average annual rate of 2.6% over the same period projected by IHSGI and the Congressional Budget Office (CBO) and by the International Energy Agency (IEA) in its November 2013 *World Energy Outlook* Current Policies Scenario.

The average annual GDP growth of 2.5% in the AEO2014 Reference case from 2012 to 2025 is in the low range of the outlooks, with IHSGI and ExxonMobil projecting similar growth, while OMB and INFORUM project slightly higher mid-term growth, at 2.6%/year. SSA and OEG project annual average growth of 2.7% from 2012 to 2025. IEA projects the highest midterm growth, at 2.8%/year from 2012 to 2025. The CBO projects the lowest annual GDP growth, averaging 2.4% from 2012 to 2025.

There are few public or private projections of GDP growth for the United States that extend to 2040. The AEO2014 Reference case projects 2.4% average annual GDP growth from 2012 to 2040, consistent with trends in labor force and productivity growth. SSA, IEA, ExxonMobil, and INFORUM also project GDP growth averaging 2.4%/year from 2012 to 2040, while IHSGI and OEG project higher rates of 2.5% and 2.6%/year, respectively, from 2012 to 2040.

CP2. Oil prices

In the AEO2014 Reference case, oil prices are represented by spot prices for North Sea Brent crude. Prices decline in the Reference case from $112/barrel in 2012 to about $109/barrel in 2025 and then rise slowly to $130/barrel in 2035 and $141/barrel in 2040 (Table CP2). In AEO2014, the North Sea Brent crude oil price is tracked as the main benchmark for world oil prices, because it reflects the marginal price paid by refineries for imported light, sweet crude oil (used to produce petroleum products for consumers) better than does the West Texas Intermediate (WTI) crude oil price. The WTI price continued to trade at a discount relative to other world oil prices in 2013. The discount narrowed through the end of the summer, as a result of new U.S. oil transportation infrastructure out of the market center for WTI prices in Cushing, Oklahoma, and refineries running at record levels. In 2012, the WTI and North Sea Brent prices differed by $18/barrel. In the AEO2014 Reference case, the gap closes to $2/barrel in 2020 and

Table CP1. Comparisons of average annual economic growth projections, 2012-40

	Average annual percentage growth rates			
Projection	2012-2015	2012-2025	2025-2040	2012-2040
AEO2014 (Reference case)	2.6	2.5	2.4	2.4
AEO2013 (Reference case)	2.6	2.6	2.4	2.5
IHSGI (May 2013)	2.6	2.5	2.4	2.5
OMB (January 2014)[a]	2.7	2.6	--	--
CBO (February 2014)[a]	2.6	2.5	--	--
INFORUM (November 2013)	2.4	2.6	2.3	2.4
Social Security Administration (August 2013)	3.0	2.7	2.2	2.4
IEA (2013)[b]	2.6	2.8	--	2.4
ExxonMobil	--	2.5	2.2	2.4
OEG (January 2013)	2.7	2.7	2.5	2.6

-- = not reported or not applicable.
[a]OMB and CBO projections end in 2024, and growth rates cited are for 2012-24. AEO projections end in 2040.
[b]IEA publishes U.S. growth rates for certain intervals: 2011-15 growth is 2.6%, 2011-20 growth is 2.8%, and 2011-35 growth is 2.4%.

remains at that level throughout the projection period, following resolution of most of the transportation system constraints in the United States. In each of the other outlooks in the comparison, oil spot prices are based on either North Sea Brent or WTI prices, with the exception of IEA spot prices, which are based on the international average of crude oil import prices within the member countries of the Organization for Economic Cooperation and Development (OECD).

The range of oil price projections for both the near term and the long term reflects market volatility caused by persistent political instability in major producing countries in the developing world, as well as different assumptions about the future of the world economy. However, with the exception of Strategic Energy & Economic Research (SEER), the projections show oil prices rising over the entire projection period. The projections for 2025 range from $60/barrel to $117/barrel for WTI and from $64/barrel to $127/barrel for North Sea Brent. The projections for 2040 range from $52/barrel to $164/barrel for WTI and from $54/barrel to $171/barrel for North Sea Brent. The wide range underscores the uncertainty inherent in the projections. Again, with the exception of SEER, the spread of the projections is encompassed in the AEO2014 Low and High Oil Price cases, which range from $70/barrel to $159/barrel for Brent in 2025 and from $75/barrel to $204/barrel in 2040.

CP3. Total energy consumption

Four projections by other organizations—INFORUM, IHSGI, ExxonMobil, and IEA—include energy consumption by sector. To allow comparison with the IHSGI projection, the AEO2014 Reference case was adjusted to remove coal-to-liquids (CTL) heat and power, natural gas-to-liquids heat and power, biofuels heat and coproducts, and natural gas feedstock use. To allow comparison with the ExxonMobil projection, electricity consumption in each sector was removed from the AEO2014 Reference case. To allow comparison with the IEA projections, the AEO2014 Reference case projections for the residential and commercial sectors were combined to produce a buildings sector projection (Table CP3). The IEA projections have a base year of 2011 and extend only through 2035. ExxonMobil provided base year data for 2010.

Both IEA and ExxonMobil account for electricity generation with renewable energy at the electricity conversion rate of 3,412 Btu per kilowatthour rather than at a displaced fossil fuel heat rate used in the AEO and other projections, which lowers their estimates of total energy consumption. ExxonMobil also includes a cost for carbon dioxide (CO_2) emissions, 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-2013) is used for comparison in this analysis, because it corresponds better with the assumptions in the AEO2014 Reference case. In all years shown, ExxonMobil and IEA show lower total energy consumption in comparison with the AEO2014 Reference case. Total energy consumption is higher in all years of the IHSGI projection than in the AEO2014 Reference case but starts from a lower level.

The INFORUM projection of total energy consumption in 2040 is similar to the AEO2014 Reference case projection, but the INFORUM projection for the transportation sector is 1.5 quadrillion Btu higher than the AEO2014 projection, and the buildings sector is 0.6 quadrillion Btu higher. Those higher levels of energy consumption are offset by a 2.5 quadrillion Btu lower level of industrial sector consumption in the INFORUM projection. For the transportation sector, the INFORUM projection features strong growth in diesel fuel demand from 2011 to 2020 (more than 1.2 quadrillion Btu above the 2011 level). However, from 2020 to 2040, growth is less than one-half (0.6 quadrillion Btu) that in the earlier period. The INFORUM projection for motor gasoline is lower than the AEO2014 projection in 2020 but does not decline as quickly afterward. The INFORUM projection for the industrial sector is lower than the AEO2014 projection despite higher industrial output, implying greater efficiency improvement.

Table CP2. Comparisons of oil price projections, 2025, 2035, and 2040 (2012 dollars per barrel)

			Projections					
	2012		2025		2035		2040	
	WTI	Brent	WTI	Brent	WTI	Brent	WTI	Brent
AEO2014 (Reference case)	94.12	111.65	106.99	108.99	127.77	129.77	139.46	141.46
AEO2014 (Low Oil Price case)	94.12	111.65	68.40	70.40	71.40	73.40	72.90	74.90
AEO2014 (High Oil Price case)	94.12	111.65	156.62	158.62	185.92	187.92	202.24	204.24
AEO2013 (Reference case)	94.12	110.43	117.41	119.45	145.96	147.99	163.54	165.57
SEER	94.15	111.63	60.00	64.00	54.00	56.00	52.00	54.00
ArrowHead Economics	94.12	111.65	101.94	108.34	119.61	124.00	131.34	135.42
Energy Ventures Associates (EVA)	94.12	--	85.64	--	106.01	--	--	--
INFORUM	--	111.65	--	123.86	--	154.26	--	171.16
Energy Security Analysis (ESAI)	--	111.50	--	99.10	--	125.30	--	131.30
IEA (Current Policies Scenario)[a]	94.12	111.65	--	127.00	--	145.00	--	--

-- = not reported.
[a]IEA mixed crude oil import prices are based on OECD member country reporting.

IHSGI projects significantly higher electricity consumption for all sectors than the AEO2014 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 4.9 quadrillion Btu more energy in 2040 than in the AEO2014 Reference case. The greater use of electricity in the IHSGI projection, including 152 trillion Btu used in the transportation sector (more than double the amount in AEO2014), also results in higher electricity prices than in the AEO2014 Reference case.

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 AEO2014 Reference case. Energy consumption in the transportation sector declines from 2010 levels in the ExxonMobil projection, based on expected policy changes, efficiency improvements, and the penetration of new technologies.

Table CP3. Comparisons of energy consumption projections by sector, 2025, 2035, and 2040 (quadrillion Btu)

Sector	*AEO2014* Reference	INFORUM	IHSGI	ExxonMobil	IEA
	2012 (except where noted)[a]				
Residential	10.4	10.6	10.0	11.0[b]	--
Residential excluding electricity	5.7	5.9	5.4	5.0[b]	--
Commercial	8.3	8.3	8.2	8.0[b]	--
Commercial excluding electricity	3.8	3.8	3.7	4.0[b]	--
Buildings Sector	18.7	18.9	18.3	--	19.0[c]
Industrial	23.6	23.9	--	24.0[b]	23.5[c]
Industrial excluding electricity	20.3	20.5	--	20.0[b]	--
Losses[d]	0.5	--	--	--	--
Natural gas feedstocks	0.9	--	--	--	--
Industrial removing losses and feedstocks	22.2	--	21.8	--	--
Transportation	26.7	26.7	25.9	27.0[b]	23.4[c]
Electric Power	38.5	38.2	39.4	37.0[b]	36.3[c]
Less: electricity demand[e]	12.6	12.6	12.6	--	14.9[c]
Electric power losses	26.0	--	--	--	--
Total primary energy	**95.0**	**95.1**	**--**	**94.0[b]**	**86.9[c]**
Excluding losses[d] and feedstocks	**93.6**	**--**	**92.7**	**--**	**--**
	2025				
Residential	10.8	11.2	11.6	10.0	--
Residential excluding electricity	5.8	6.0	5.8	5.0	--
Commercial	9.1	9.2	9.4	9.0	--
Commercial excluding electricity	4.1	4.3	4.0	4.0	--
Buildings sector	19.9	20.4	21.0	--	--
Industrial	29.0	26.8	--	26.0	--
Industrial excluding electricity	24.8	22.8	--	21.0	--
Losses[d]	0.8	--	--	--	--
Natural gas feedstocks	1.1	--	--	--	--
Industrial removing losses and feedstocks	27.2	--	24.9	--	--
Transportation	25.6	26.7	27.6	26.0	--
Electric power	42.2	42.2	47.1	37.0	--
Less: electricity demand[e]	14.3	14.2	15.7	--	--
Electric power losses	27.9	--	--	--	--
Total primary energy	**102.5**	**101.9**	**--**	**93.0**	**--**
Excluding losses[d] and feedstocks	**100.6**	**--**	**105.0**	**--**	**--**

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

(continued on next page)

Total energy consumption in the IEA projection is higher in 2035 than in 2011 because of a 3.7 quadrillion Btu increase in buildings sector energy consumption, including a 3.1 quadrillion Btu increase in electricity consumption. IEA projects little change in energy use in the industrial sector from 2020 to 2035. Energy consumption in the transportation sector is projected to increase by 0.3 quadrillion Btu through 2020, decline by 0.3 quadrillion Btu from 2020 through 2030, and increase by 0.4 quadrillion Btu from 2030 to 2035. The increases from 2011 through 2020 and from 2030 through 2035 reflect growing biofuel use for transportation. The

Table CP3. Comparisons of energy consumption by sector projections, 2025, 2035, and 2040 (quadrillion Btu) (continued)

Sector	*AEO2014* Reference	INFORUM	IHSGI	ExxonMobil	IEA
			2035		
Residential	10.9	11.5	12.2	10.0	--
Residential excluding electricity	5.5	5.7	5.7	5.0	--
Commercial	9.7	9.8	10.1	9.0	--
Commercial excluding electricity	4.3	4.4	4.0	3.0	--
Buildings sector	20.6	21.3	22.3	--	22.7
Industrial	29.8	26.9	--	26.0	25.5
Industrial excluding electricity	25.5	23.1	--	20.0	--
Losses[d]	0.8	--	--	--	--
Natural gas feedstocks	1.0	--	--	--	--
Industrial removing losses and feedstocks	28.0	--	25.5	--	--
Transportation	25.1	26.4	27.6	25.0	23.7
Electric power	43.9	44.0	49.6	36.0	42.3
Less: electricity demand[e]	15.2	15.1	17.3	--	18.6
Electric power losses	28.7	--	--	--	--
Total primary energy	**104.3**	**103.5**	**--**	**90.0**	**95.3**
Excluding losses[d] and feedstocks	**102.5**	**--**	**107.8**	**--**	**--**
			2040		
Residential	10.9	11.7	12.6	10.0	--
Residential excluding electricity	5.3	5.6	5.7	5.0	--
Commercial	10.2	10.1	10.3	9.0	--
Commercial excluding electricity	4.5	4.4	4.1	3.0	--
Buildings sector	21.2	21.8	22.9	--	--
Industrial	30.2	27.7	--	25.0	--
Industrial excluding electricity	25.9	23.9	--	20.0	
Losses[d]	0.8	--	--	--	--
Natural gas feedstocks	1.0	--	--	--	--
Industrial removing losses and feedstocks	28.4	--	26.1	--	--
Transportation	25.5	27.0	27.8	24.0	--
Electric power	45.2	45.1	50.1	36.0	--
Less: electricity demand[e]	15.8	15.6	17.9	--	--
Electric power losses	29.4	--	--	--	--
Total primary energy	**106.3**	**106.0**	**--**	**88.0**	**--**
Excluding losses[d] and feedstocks	**104.5**	**--**	**108.9**	**--**	**--**

-- = not reported.

[a]Base year varies by projection or data for 2012 may differ based on coverage.

[b]ExxonMobil data are for 2010.

[c]IEA data are for 2011.

[d]Losses in CTL and biofuel production.

[e]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.

decline from 2020 through 2030 reflects a drop in petroleum use. The IEA projection for total energy consumption in 2035 is higher than the ExxonMobil projection but considerably lower than projected in the AEO2014 Reference case for both 2030 and 2035.

CP4. Electricity

Table CP4 compares summary results for electricity from the AEO2014 Reference case with projections from EVA, IHSGI, INFORUM, and ICF International, Incorporated (ICF). The AEO2014 Reference case, EVA, and INFORUM project modest growth in total electricity sales over the coming decades. The AEO2014 Reference case projects 4,178 billion kilowatthours (kWh) of total electricity sales in 2025. By comparison, IHSGI projects 4,600 billion kWh of total electricity sales in 2025, which is 10% higher than the AEO2014 Reference case projection, and higher than the EVA and INFORUM projections. The IHSGI projection for total electricity sales is also the highest among the projections in 2035 and 2040. Similarly, IHSGI's individual sector level sales projections are the highest among the projections in 2025, 2035 and 2040.

Table CP4. Comparisons of electricity projections, 2025, 2035, and 2040 (billion kilowatthours, except where noted)

Sector	2012	*AEO2014* Reference	EVA	IHSGI	INFORUM	ICF
				2025		
Average end-use price (2012 cents per kilowatthour)[a]	9.8	10.1	--	11.3	12.3	--
Residential	11.9	12.3	--	13.6	15.0	--
Commercial	10.1	10.4	--	11.7	12.7	--
Industrial	6.7	7.2	--	7.6	8.4	--
Total generation plus net imports	**4,102**	**4,658**	**4,324**	**5,108**	**--**	**4,772**
Coal	1,512	1,689	1,753	1,454	--	1,684
Petroleum	23	19	--	23	--	15
Natural gas[b]	1,239	1,419	1,150	1,848	--	1,505
Nuclear	769	779	846	875	--	811
Hydroelectric/other[c]	511	717	575	842	--	756
Solar	11	42	26	--	--	43
Wind	142	219	217	364	--	268
Net imports	47	35	--	66	--	--
Electricity sales[d]	3,686	4,178	4,067	4,600	4,141	--
Residential	1,375	1,467	1,428	1,703	1,508	--
Commercial/other[e]	1,331	1,459	1,420	1,621	1,460	--
Industrial	981	1,253	1,220	1,277	1,174	--
Capacity, including CHP (gigawatts)[f]	1,066	1,110	1,109	1,225	--	1,123
Coal	310	262	254	263	--	245
Oil and natural gas	471	527	539	567	--	541
Nuclear	102	98	104	110	--	103
Hydroelectric/other[g]	182	223	211	285	--	234
Solar	8	25	19	--	--	27
Wind	59	76	80	124	--	94
Cumulative capacity retirements from 2011 (gigawatts)[h]	--	87	--	98	--	104
Coal	--	51	--	51	--	66
Oil and natural gas	--	31	--	45	--	30
Nuclear	--	5	--	2	--	8
Hydroelectric/other[g]	--	1	--	--	--	1

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

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The AEO2014 Reference case, IHSGI, and INFORUM provide projections for average electricity prices by sector for 2025, 2035, and 2040. On average, the lowest electricity price projections are in the AEO2014 Reference case, and the highest are in the INFORUM projection. The lowest prices by sector in 2025 are in the AEO2014 Reference case (12.3 cents/kWh for the residential sector, 10.4 cents/kWh for the commercial/other sector, and 7.2 cents/kWh for the industrial sector). The highest average electricity prices by sector in 2025 are in the INFORUM projection (15.0 cents/kWh for the residential sector, 12.7 cents/kWh for the commercial sector, and 8.4 cents/kWh for the industrial sector). The AEO2014 Reference case, IHSGI, and INFORUM reflect similar relative price patterns for 2035 and 2040.

The AEO2014 Reference case projects total U.S. generation plus imports of 4,658 billion kWh for 2025. By comparison, IHSGI projects 5,108 billion kWh of total U.S. generation plus imports for 2025, which is the highest among the projections reported. IHSGI's projections for total U.S. electricity generation plus imports continue to be the highest among the projections considered for 2035 and 2040.

Table CP4. Comparisons of electricity projections, 2025, 2035, and 2040 (billion kilowatthours, except where noted) (continued)

Sector	2012	*AEO2014* Reference	EVA	IHSGI	INFORUM	ICF
		2035				
Average end-use price (2012 cents per kilowatthour)[a]	9.8	10.7	--	11.9	16.1	--
Residential	11.9	12.9	--	14.4	19.3	--
Commercial	10.1	10.9	--	12.3	16.4	--
Industrial	6.7	7.8	--	8.0	10.9	--
Total generation plus net imports	**4,102**	**5,034**	**4,765**	**5,606**	**--**	**5,242**
Coal	1,512	1,679	1,661	1,203	--	1,609
Petroleum	23	19	--	22	--	4
Natural gas[b]	1,239	1,726	1,828	2,362	--	2,122
Nuclear	769	786	665	898	--	593
Hydroelectric/other[c]	511	793	611	1,066	--	913
Solar	11	61	34	--	--	49
Wind	142	227	241	513	--	397
Net imports	47	31	--	55	--	--
Electricity sales[d]	3,686	4,454	4,510	5,057	4,398	--
Residential	1,375	1,585	1,605	1,910	1,685	--
Commercial/other[e]	1,331	1,604	1,624	1,801	1,596	--
Industrial	981	1,265	1,281	1,347	1,117	--
Capacity, including CHP (gigawatts)[f]	1,066	1,237	1,215	1,385	--	1,266
Coal	310	262	231	227	--	244
Oil and natural gas	471	633	674	685	--	660
Nuclear	102	99	84	114	--	77
Hydroelectric/other[g]	182	243	227	360	--	286
Solar	8	36	25	--	--	32
Wind	59	80	89	169	--	138
Cumulative capacity retirements from 2011 (gigawatts)[h]	--	96	--	172	--	129
Coal	--	51	--	92	--	69
Oil and natural gas	--	40	--	70	--	30
Nuclear	--	5	--	11	--	29
Hydroelectric/other[g]	--	1	--	--	--	1

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

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In the AEO2014 Reference case, generation from coal-fired plants is projected to exceed generation from natural-gas fired plants by 270 billion kWh in 2025. By comparison, in the IHSGI projection for 2025, total natural gas-fired generation is projected to exceed coal-fired generation by 394 billion kWh. IHSGI has previously projected that the total generation from natural gas-fired plants would exceed that for coal-fired plants in 2024 as a result of the assumed implementation of a carbon tax. In the AEO2014

Table CP4. Comparisons of electricity projections, 2025, 2035, and 2040 (billion kilowatthours, except where noted) (continued)

Sector	2012	*AEO2014* Reference	EVA	IHSGI	INFORUM	ICF
		2040				
Average end-use price (2012 cents per kilowatthour)[a]	9.8	11.1	--	12.1	19.1	--
Residential	11.9	13.3	--	14.5	22.8	--
Commercial	10.1	11.3	--	12.4	19.3	--
Industrial	6.7	8.2	--	8.1	12.8	--
Total generation plus net imports	**4,102**	**5,254**	**5,020**	**5,825**	**--**	**5,478**
Coal	1,512	1,675	1,477	944	--	1,483
Petroleum	23	19	--	20	--	4
Natural gas[b]	1,239	1,857	2,303	2,743	--	2,497
Nuclear	769	811	611	898	--	473
Hydroelectric/other[c]	511	857	628	1,165	--	1,021
Solar	11	86	35	--	--	50
Wind	142	250	254	573	--	491
Net imports	47	35	--	55	--	--
Electricity sales[d]	3,686	4,623	4,757	5,256	4,539	--
Residential	1,375	1,657	1,704	2,004	1,783	--
Commercial/other[e]	1,331	1,693	1,742	1,869	1,651	--
Industrial	981	1,273	1,310	1,384	1,105	--
Capacity, including CHP (gigawatts)[f]	1,066	1,316	1,273	1,448	--	1,344
Coal	310	262	202	176	--	243
Oil and natural gas	471	687	764	763	--	719
Nuclear	102	102	76	114	--	62
Hydroelectric/other[g]	182	265	231	395	--	319
Solar	8	48	25	--	--	32
Wind	59	87	93	189	--	169
Cumulative capacity retirements from 2011 (gigawatts)[h]	--	97	--	259	--	152
Coal	--	51	--	146	--	70
Oil and natural gas	--	40	--	102	--	30
Nuclear	--	5	--	11	--	50
Hydroelectric/other[g]	--	1	--	--	--	1

-- = not reported.
[a]Average end-use price includes the transportation sector.
[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]EIA 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]Retirements for AEO2014 reflect the electric power sector only.

Reference case, which is based on current laws and regulations and does not include a carbon tax, generation from natural gas-fired plants does not surpass generation from coal-fired plants until 2035.

There are varying outlooks for generation from U.S. nuclear power plants. Nuclear generation projections for the year 2025 range from a low of 779 billion kWh in the AEO2014 Reference case to a high of 875 billion kWh in the IHSGI projection. The AEO2014 Reference case reflects increasing U.S. nuclear generation, with increases to 786 billion kWh in 2035 and 811 billion kWh in 2040. In the IHSGI projection, nuclear generation increases to 898 billion kWh in 2035, and remains at 898 billion kWh in 2040. Both ICF and EVA project declines in nuclear generation through 2040.

Generation from nonhydroelectric renewable resources constitutes a significant portion of generation growth. However, the share of total generation from nonhydroelectric renewables varies across the projections. For instance, in 2035 the AEO2014 Reference case and EVA, respectively, show 5.8% and 5.8% shares of total generation from wind and solar, and IHSGI and ICF, respectively, show 9.2% and 8.5% shares from wind and solar. Part of this variation may be due to the adoption of different assumptions regarding the extension or enhancement of federal and state policies.

Total generating capacity by fuel in 2025 (including combined heat and power [CHP]) is fairly similar across the projections, ranging from 1,109 gigawatts (GW) in the EVA projection (the AEO2014 Reference case projects 1,110 gigawatts) to 1,225 GW in the IHSGI projection. IHSGI projects slightly more growth in total generating capacity, corresponding to their higher projections for both sales and generation.

Projections for capacity retirements vary widely over the 2012-40 period. Cumulative capacity retirements from 2013 through 2025 are closely aligned, ranging from a high of 104 GW in the ICF projection to 87 GW in the AEO2014 Reference case and 98 GW in the IHSGI projection. The majority of the retirements in the ICF, AEO2014 Reference case, and IHSGI projections from 2013 to 2025 are attributed to reductions in coal-fired capacity. Coal-fired capacity also represents the largest portion of cumulative retirements from 2013 to 2040. However, there is substantial variation in the projected timing of coal retirements. In the AEO2014 Reference case there are no incremental coal-fired capacity retirements from 2025 to 2035, but ICF and IHSGI project incremental coal-fired capacity retirements of 3 GW and 41 GW, respectively, over the same period. In general, the projected coal-fired capacity retirements are balanced by increases in natural gas- and oil-fired capacity (dominated by natural gas) and hydroelectric/other capacity (dominated by wind and solar).

CP5. Natural gas

The projections for natural gas consumption, production, imports, and prices differ significantly among the outlooks (Table CP5). The variations result, in large part, from differences in underlying assumptions. For example, the AEO2014 Reference case assumes that current laws and regulations remain unchanged through the projection period, whereas some of the other projections include assumptions about anticipated policy developments over the period. In particular, the AEO2014 Reference case does not incorporate any future changes in policy directed at carbon emissions or other environmental issues, while some of the other outlooks include explicit assumptions about policies aimed at reducing carbon emissions.

Production

All of the outlooks shown in Table CP5 (with the exception of ExxonMobil, which did not provide production data) project increases in natural gas production from 2012, when production totaled 24.1 trillion cubic feet (Tcf). EVA projects the largest production increase, to 38.3 Tcf in 2035, or 59% more than the 2012 level. EVA is followed closely by IHSGI, which projects 38.1 Tcf of natural gas production in 2035, a 58% increase over 2012 levels. ICF projects the third-highest production growth after EVA and IHSGI, at 37.4 Tcf in 2035. ICF, EVA, and IHSGI all project significantly larger increases in natural gas production before 2025 than in the later years.

The AEO2014 Reference case and BP, p.l.c. (BP) project relatively modest growth in natural gas production, particularly in the near term. The two projections show natural gas production increasing more rapidly, on average, from 2012 to 2025 than from 2025 to 2035. In the AEO2014 Reference case, natural gas production rises by 50% from 2012 to 2035, when total production is 36.1 Tcf. BP projects a production increase of 46% from 2012 to 35.1 Tcf in 2035.

INFORUM shows by far the lowest growth in natural gas production from 2012 through 2035, at 15%, with total production of 27.7 Tcf in 2035. INFORUM also projects relatively higher production growth from 2012 to 2025 than from 2025 to 2035.

Net imports/exports

The AEO2014 Reference case projects the strongest export growth over the 2012-35 period, attributable to exports via pipeline and as liquefied natural gas (LNG). The United States becomes a net LNG exporter by 2016 and an overall net exporter of natural gas by 2018. In 2035, the United States has net exports of 5.5 Tcf of natural gas, as a result of further growth in both LNG exports and net pipeline exports. U.S. exports of LNG from new liquefaction capacity surpass 2.0 Tcf in 2020 and increase to 3.5 Tcf in 2029. In addition, net pipeline exports increase to 2.2 Tcf in the AEO2014 Reference case, buoyed by higher net pipeline exports to Mexico and lower net pipeline imports from Canada.

All of the other projections show the United States becoming a net natural gas exporter by 2020, but they differ from AEO2014 in terms of export levels. Both EVA and IHSGI show net exports peaking early in the projection period but declining through 2035, with net exports in 2035 that are less than one-quarter of those in the AEO2014 Reference case. Both EVA and IHSGI show the domestic sector consuming a greater portion of U.S. natural gas production than in the AEO2014 Reference case. In the EVA and IHSGI projections, U.S. net natural gas exports in 2035 total 1.0 and 1.3 Tcf, respectively. Unlike IHSGI, the EVA projection of 3.2 Tcf of net LNG exports in 2035 is fairly close to the 3.4 Tcf in the AEO2014 Reference case in 2035. EVA differs from the Reference

Table CP5. Comparisons of natural gas projections, 2025, 2035, and 2040 (trillion cubic feet, except where noted)

Projection	2012	*AEO2014* Reference	IHSGI	EVA	ICF	BP[a]	ExxonMobil	INFORUM
					2025			
Dry gas production[b]	24.06	31.86	34.26	33.14	33.15	31.96	--	26.20
Net imports	**1.51**	**-3.41**	**-1.81**	**-2.34**	**-3.02**	**--**	**--**	**--**
Pipeline	1.37	-0.84	--	0.64	-0.80	--	--	--
LNG	0.15	-2.57	--	-2.99	-2.22	--	--	--
Consumption	**25.64**	**28.35**	**32.52**	**32.15**	**29.64**	**28.28**	**29.30[c]**	**24.84[c]**
Residential	4.17	4.40	4.60	5.09	5.04	--	8.00[d]	4.71
Commercial	2.90	3.22	3.24	3.55	3.11	--	--	3.38
Industrial[e]	7.14	8.41	7.96	9.56	7.96	--	9.00	7.82
Electric generators[f]	9.25	9.49	13.28	10.61	10.90	--	12.00	8.92
Others[g]	2.18	2.84	3.45	3.35	2.64	--	0.30	--
Henry Hub spot market price (2012 dollars per million Btu)	2.75	5.23	3.92	5.69	5.44[h]	--	--	--
End-use prices (2012 dollars per thousand cubic feet)								
Residential	10.69	12.75	11.37	--	--	--	--	--
Commercial	8.29	10.51	9.26	--	--	--	--	--
Industrial[i]	3.85	6.46	6.18	--	--	--	--	--
Electricity generation	3.51	5.88	4.60	--	--	--	--	--
					2035			
Dry gas production[b]	24.06	36.09	38.07	38.32	37.45	35.14	--	27.72
Net imports	**1.51**	**-5.53**	**-1.33**	**-1.04**	**-3.66**	**--**	**--**	**--**
Pipeline	1.37	-2.16	--	2.15	-1.47	--	--	--
LNG	**0.15**	-3.37	--	-3.19	-2.19	--	--	--
Consumption	**25.64**	**30.44**	**36.66**	**39.13**	**33.39**	**31.13**	**31.70[c]**	**25.19[c]**
Residential	4.17	4.23	4.56	5.07	5.00	--	7.00[d]	4.53
Commercial	2.90	3.40	3.33	3.62	2.93	--	--	3.51
Industrial[e]	7.14	8.59	7.55	10.56	8.19	--	9.00	7.80
Electric generators[f]	9.25	10.67	16.17	15.76	14.28	--	15.00	9.36
Others[g]	2.18	3.54	5.06	4.14	3.00	--	0.70	--
Henry Hub spot market price (2012 dollars per million Btu)	2.75	6.92	4.42	6.46	6.89[h]	--	--	--
End-use prices (2012 dollars per thousand cubic feet)								
Residential	10.69	14.93	11.88	--	--	--	--	--
Commercial	8.29	12.22	9.79	--	--	--	--	--
Industrial[i]	3.85	7.93	6.69	--	--	--	--	--
Electricity generation	3.51	7.45	5.13	--	--	--	--	--

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

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case in that it projects net pipeline imports of natural gas into the United States after 2020, rather than net pipeline exports, with gross natural gas pipeline imports into the United States more than tripling between 2025 and 2035.

In the ICF projection, the United States becomes a net exporter of both pipeline gas and LNG by 2025, and remains so through 2035. The increase in net exports in the ICF projection, to 3.7 Tcf in 2035, is significantly larger than projected by EVA and IHSGI but significantly smaller than projected in the AEO2014 Reference case. The AEO2014 and ICF production and price projections are similar to each other, but the ICF projection shows less natural gas going to other countries and more consumed at home.

Consumption

In the AEO2014 Reference case, total domestic natural gas consumption increases by 19% from 2012 to 2035 when it totals 30.4 Tcf, which is the lowest projected increase in total consumption among the comparable projections. Although the INFORUM projection shows lower volumes, they are not comparable since they are missing natural gas consumed for lease and plant operations and as a pipeline fuel. The 4.8 Tcf increase in total domestic consumption in the AEO2014 Reference case is also 32% less than the projected 7.0 Tcf increase in natural gas net exports, whereas IHSGI, EVA, and ICF all show domestic consumption growth exceeding net export growth through 2035. The AEO2014 Reference case projects more rapid growth in industrial consumption from 2012 to 2035 (20%, to a total of 8.6 Tcf in 2035) than in power sector consumption (15%, to 10.7 Tcf in 2035). Some of the variation in electric sector consumption may be the result of different assumptions about potential fees on carbon emissions, which are not included in the AEO2014 Reference case.

Table CP5. Comparisons of natural gas projections, 2025, 2035, and 2040 (trillion cubic feet, except where noted) (continued)

Projection	2012	*AEO2014* Reference	IHSGI	EVA	ICF	BP[a]	ExxonMobil	INFORUM
		2040						
Dry gas production[b]	24.06	37.54	40.80	--	--	--	--	31.58
Net imports	**1.51**	**-5.80**	**-0.90**	**-1.13**	**--**	**--**	**--**	**--**
Pipeline	1.37	-2.43	--	2.06	--	--	--	--
LNG	0.15	-3.37	--	-3.19	--	--	--	--
Consumption	**25.64**	**31.63**	**39.83**	**40.99**	**--**	**--**	**31.00[c]**	**24.86[c]**
Residential	4.17	4.12	4.56	5.06	--	--	7.00[d]	4.43
Commercial	2.90	3.57	3.38	3.63	--	--	--	3.58
Industrial[e]	7.14	8.68	7.39	11.09	--	--	8.00	7.84
Electric generators[f]	9.25	11.23	18.43	16.90	--	--	15.00	9.01
Others[g]	2.18	4.03	6.07	4.30	--	--	1.00	--
Henry Hub spot market price (2012 dollars per million Btu)	2.75	7.65	4.54	--	--	--	--	--
End-use prices (2012 dollars per thousand cubic feet)								
Residential	10.69	16.33	12.00	--	--	--	--	--
Commercial	8.29	13.37	9.91	--	--	--	--	--
Industrial[i]	3.85	8.78	6.81	--	--	--	--	--
Electricity generation	3.51	8.34	5.26	--	--	--	--	--

-- = not reported.

[a]Projections for total consumption and production are for all of North America. Consumption by type provided only on a worldwide level. The conversion factor used is 1 million metric tons of oil equivalent = 39.2 billion cubic feet of natural gas.

[b]Does not include supplemental fuels.

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

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

[e]Includes consumption for industrial 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.

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

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

[h]Converted to 2012 dollars using EIA's GDP deflator.

[i]The IHSGI 2012 industrial natural gas price is $4.84 per million Btu.

IHSGI, EVA, and ICF show higher projections for total natural gas consumption in 2035 than in the AEO2014 Reference case, with consumption in the electric power sector accounting for a larger share of total U.S. consumption than other sectors. IHSGI shows the largest increase in electric power sector consumption through 2035, at 75%, with 2035 consumption totaling 16.2 Tcf. EVA shows a 70% increase, to 15.8 Tcf in 2035.

EVA differs from IHSGI in that it shows industrial consumption growing to 10.6 Tcf in 2035 (the highest level among the projections), whereas IHSGI shows relatively flat consumption in the industrial sector. EVA also differs from IHSGI in its projection for the electric power sector, which shows most growth occurring after 2025, whereas the IHSGI projection shows most of the growth in electric power sector natural gas use occurring before 2025. Like EVA and the AEO2014 Reference case, ICF projects most growth in electric power sector natural gas consumption occurring after 2025. ICF projects 54% growth in power sector natural gas use, to 14.3 Tcf in 2035, which is less than projected by IHSGI and EVA but significantly more than in the AEO2014 Reference case. The AEO2014 projection for natural gas consumption in the electric power sector is lower than the others, but its projection for industrial sector natural gas consumption in 2035 is exceeded only by EVA and ExxonMobil.

ExxonMobil projects electric power sector natural gas consumption growth of 62% to 15.0 Tcf in 2035. Like EVA and ICF, ExxonMobil shows most of the growth occurring after 2025. ExxonMobil also projects strong growth for natural gas consumption in the industrial sector, to 9.0 Tcf in 2035. Although the BP projection shows lower production growth than AEO2014 through 2035, it shows higher growth in domestic natural gas consumption, presumably as a result of lower net exports. Only INFORUM projects lower consumption growth than the AEO2014 Reference case through 2035. In the INFORUM projection, delivered (excluding lease, plant, and pipeline fuel) U.S. natural gas consumption totals 25.2 Tcf in 2035—less than the 2012 total.

Prices

Only four of the outlooks included in Table CP5 provide projections for Henry Hub natural gas spot prices. Prices from IHSGI are significantly lower than those in the AEO2014 Reference case, EVA, and ICF projections, particularly in the later years. IHSGI projects a Henry Hub price of $4.42 in 2035, in 2012 dollars/million Btu (MMBtu). All the other projections are well over $6/MMBtu, even though the IHSGI production level is one of the highest. Through 2025, the AEO2014 Reference case has the second lowest projected Henry Hub prices after IHSGI; however, it has the highest projected 2035 spot price, at $6.92/MMBtu in real 2012 dollars, followed by EVA and ICF, at $6.46 and $6.89/MMBtu, respectively.

In the AEO2014 Reference case, commercial, residential, electric power, and industrial natural gas prices all rise from 2012 to 2035 by between $3.93 and $4.24/thousand cubic feet (Mcf) in real 2012 dollars. IHSGI is the only other outlook that projects natural gas prices by sector, and like the IHSGI Henry Hub price projection, they are far lower than those in the AEO2014 Reference case. IHSGI projects price increases from 2012 to 2035 ranging from $1.19/Mcf in the residential sector to $2.84/Mcf in the industrial sector, with the commercial and electric power sectors increasing by $1.50 and $1.61/Mcf, respectively.

CP6. Petroleum and other liquid fuels

In the AEO2014 Reference case, the North Sea Brent crude oil spot price (in 2012 dollars) declines from about $112/barrel in 2012 to $109/barrel in 2025 before rising to $130/barrel in 2035 and $141/barrel in 2040 (Table CP6). North Sea Brent crude oil spot prices increase steadily in the INFORUM projection, rising from $124/barrel in 2025 to $154/barrel in 2035. In the AEO2014 Reference case, the U.S. imported refiner acquisition cost (IRAC) for crude oil (in 2012 dollars) declines to about $100/barrel in 2025, then increases to $120/barrel in 2035 and $131/barrel in 2040. IRAC prices in the IEA projection are higher, ranging from $112/barrel in 2025 to $140/barrel in 2035. BP, EVA, ExxonMobil, and IHSGI did not report projections of North Sea Brent or IRAC crude oil prices.

In the AEO2014 Reference Case, domestic crude oil production increases from about 6.5 million barrels/day (MMbbl/d) in 2012 to a peak of 9.6 MMbbl/d in 2019 before falling to 9.0 MMbbl/d in 2025, about 7.9 MMbbl/d in 2035, and 7.5 MMbbl/d in 2040. Overall, the production level in 2035 is more than 21% higher than in 2012. The INFORUM projection shows a considerable increase in production, to 8.8 MMbbl/d in 2035. The EVA projection shows an even steeper increase, with crude oil production reaching 11.8 MMbbl/d in 2025 before falling slightly to 11.5 MMbbl/d in 2035. Both the IHSGI and ExxonMobil projections are considerably below the AEO2014 Reference case, with domestic crude oil production in 2035 at 7.2 MMbbl/d and 4.6 MMbbl/d, respectively.

With rapid growth in U.S. crude oil production, net imports fall in the AEO2014 Reference case and in the other projections. In the AEO2014 Reference case, total net imports of crude oil and products fall from 7.5 MMbbl/d in 2012 to a low of 5.0 MMbbl/d in 2025 before increasing to 5.9 MMbbl/d in 2040. In the IHSGI projection, total net imports are slightly higher in 2025 at 6.0 MMbbl/d and rise slightly to 6.2 MMbbl/d in 2040 as a result of growing net exports of products. The BP projection shows total net imports falling to 3.7 MMbbl/d in 2025, whereas the INFORUM projection shows total net imports increasing from 6.9 MMbbl/d in 2025 to 7.0 MMbbl/d in 2035.

Biofuel production increases to about 1.0 MMbbl/d in 2025 and then remains at roughly that level through 2040 in the AEO2014 Reference case. In the BP projection, biofuel production, on an energy-equivalent basis, increases to 1.1 MMbbl/d in 2025. The IHSGI projection is slightly higher, at 1.2 MMbbl/d in 2025. BP does not show biofuel production in 2035. IHSGI shows biofuel production falling slightly to 1.1 MMbbl/d in 2035 and remaining near that level in 2040. Biofuels production is not explicitly included in the projections by EVA, INFORUM, IEA, and ExxonMobil.

Prices for diesel fuel increase through 2040 in the AEO2014 projection, while gasoline prices are lower in both 2025 and 2035 compared to 2012. INFORUM projects increases in both gasoline and diesel prices through 2035, with the gasoline price nearly equaling the diesel price in 2035. IHSGI projects falling gasoline and diesel fuel prices, with gasoline prices nearly $0.70/gallon lower and diesel fuel prices more than $1.16/gallon lower in 2040 than projected in the AEO2014 Reference case. The BP, EVA, IEA, and ExxonMobil projections do not include delivered fuel prices.

CP7. Coal

The AEO2014 Reference case generally projects the highest levels of total coal production, consumption, exports, and prices in comparison with the coal outlooks available from EVA, ICF, IHSGI, and BP (Table CP7). One key exception is INFORUM, whose projections of coal production, consumption, and exports are consistently higher than the AEO2014 projections. The IEA's *World Energy Outlook 2013* Current Policies case projections for coal consumption also are slightly higher than the AEO2014 projections, but only one year of the projection, 2035, is available for comparison.

The detailed assumptions that underlie the various projections are not generally available to EIA, although there are some important known differences that contribute to the range of outlooks. For example, the AEO2014 Reference case assumes current laws and regulations, whereas other projections reflect alternative policy outcomes affecting the coal sector, particularly with respect to the price of carbon emissions. Although not shown in Table CP7, ExxonMobil projects a larger decline in U.S. coal consumption than any other group. The ExxonMobil outlook, which features a fee on CO^2 emissions that rises to $80/metric ton (2013 dollars) in 2040, shows U.S. coal consumption declining from 17 quadrillion Btu in 2012 to 6 quadrillion Btu in 2040, an amount that is approximately 70% below the AEO2014 Reference case outlook for 2040 [*1*]. IHSGI, which has the second-lowest projection for coal consumption, assumes a CO^2 cap-and-trade program for the electricity sector that begins in 2021 and features a CO^2 allowance price that increases to $20/metric ton (2012 dollars) in 2040 [*2*]. EVA and ICF include a carbon pollution standard for

Table CP6. Comparisons of petroleum and other liquids projections, 2025, 2035, and 2040 (million barrels per day, except where noted)

Projection	2012	*AEO2014* Reference	BP[a,b]	EVA	INFORUM[c]	IEA[b]	ExxonMobil[c]	IHSGI
					2025			
U.S. refiner imported acquisition cost of crude oil (2012 dollars per barrel)	101.10	100.01	--	--	112.14	--	--	--
Brent spot price (2012 dollars per barrel)	111.65	108.99	--	--	123.86	127.00	--	--
U.S. WTI crude oil price (2012 dollars per barrel)	94.12	106.99	--	--	--	--	--	94.35
Domestic production	**8.89**	**11.88**	**12.57**	**15.30**	**--**	**--**	**--**	**11.12**
Crude oil	6.49	9.00	--	11.79	8.28	--	4.60	7.54
Alaska	0.53	0.33	--	0.34	--	--	--	--
Natural gas liquids	2.40	2.87	--	3.51	--	--	--	3.58
Total net imports	**7.52**	**5.05**	**3.74**	**--**	**6.95**	**--**	**--**	**5.99**
Crude oil	8.43	6.05	--	--	6.92	--	--	7.77
Products	-0.92	-1.01	--	--	0.03	--	--	-1.78
Petroleum and other liquids consumption	18.49	19.27	17.69	--	18.64	--	19.04	19.82
Net petroleum import share of liquids supplied (percent)	40	26	21	--	--	--	--	30
Biofuel production	0.91	0.97	1.14	--	--	--	--	1.16
Transportation product prices (2012 dollars per gallon)								
Gasoline	3.69	3.29	--	--	4.04	--	--	3.27
Diesel	3.95	3.98	--	--	4.30	--	--	3.60

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

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new plants. ICF also includes a carbon cap-and-trade program beginning in 2023. EVA, ICF, and IHSGI assume the implementation of new regulations for cooling water intake and coal combustion residuals. Because those policies are not current law, the AEO2014 Reference case excludes them, which contributes to the lower coal consumption projections in many of the other outlooks relative to AEO2014. Variation among the assumptions about growth in energy demand and other fuel prices, particularly for natural gas, also contribute to the differences.

Although the AEO2014 Reference case projection for total coal consumption is somewhat lower than the INFORUM and IEA projections, the other outlooks offer more pessimistic projections. IHSGI is the most pessimistic, with coal consumption 30% and 44% lower in 2035 and 2040, respectively, than in the AEO2014 Reference case. Lower natural gas prices (37% lower in 2040 than in the AEO2014 Reference case) and a CO^2 allowance price assumption for the power sector are key reasons for lower coal consumption in the IHSGI projection. In the EVA outlook, coal consumption in 2035 is only 2% less than in the AEO2014 Reference case; in the ICF outlook it is 14% lower. From 2035 to 2040, the differences between the EVA and ICF projections and the AEO2014 Reference case widen: in the EVA outlook, coal consumption in 2040 is 16% below the AEO2014 Reference case projection, and in the ICF outlook it is 21% lower than in the AEO2014 Reference case. The BP outlook for total coal consumption is 9% lower than the AEO2014 Reference case in 2025 and 19% lower in 2035, whereas the INFORUM outlook is 25% (247 million tons) higher in 2035 and 32% (315 million tons) higher in 2040 than projected in the AEO2014 Reference case.

The electricity sector is the predominant consumer of coal and the primary source of differences among the projections, due to differing assumptions about regulations and the economics of coal versus other fuels over time. Because the power sector accounts for more than 90% of total U.S. coal consumption, the variations in the projections for electricity sector coal consumption across the different groups primarily mirror those for total coal consumption. In 2025, the projected levels of electricity sector coal consumption for the three groups that supplied projections for all three comparison years (EVA, ICF, and IHSGI) range from 16% less to 2% more than in AEO2014. The range widens to between 30% below and 0% difference in 2035 and 44% below to 16% below in 2040, with IHGSI representing the lower end of the range and EVA the upper end. Electricity sector coal use in the EVA projection aligns most closely with the AEO2014 projection, although the two diverge after 2035, with EVA projecting a decline

Table CP6. Comparisons of petroleum and other liquids projections, 2025, 2035, and 2040 (million barrels per day, except where noted) (continued)

Projection	2012	*AEO2014* Reference	BP[a,b]	EVA	INFORUM[c]	IEA[b]	ExxonMobil[c]	IHSGI
		2035						
U.S. refiner imported acquisition cost of crude oil (2012 dollars per barrel)	101.10	119.80	--	--	139.67	--	--	--
Brent spot price (2012 dollars per barrel)	111.65	129.77	--	--	154.26	145.00	--	--
U.S. WTI crude oil price (2012 dollars per barrel)	94.12	127.77	--	--	--	--	--	95.66
Domestic production	**8.89**	**10.92**	**11.99**	**15.24**	**--**	**--**	**--**	**10.84**
Crude oil	6.49	7.87	--	11.46	8.76	--	4.60	7.16
Alaska	0.53	0.38	--	0.00	--	--	--	--
Natural gas liquids	2.40	3.05	--	3.78	--	--	--	3.68
Total net imports	**7.52**	**5.54**	**--**	**--**	**7.00**	**--**	**--**	**6.13**
Crude oil	8.43	7.15	--	--	7.26	--	--	7.39
Products	-0.92	-1.61	--	--	-0.26	--	--	-1.26
Petroleum and other liquids consumption	18.49	18.76	--	--	18.06	16.33	18.53	19.55
Net petroleum import share of liquids supplied (percent)	40	30	--	--	--	--	--	31
Biofuel production	0.91	0.97	--	--	--	--	--	1.09
Transportation product prices (2012 dollars per gallon)								
Gasoline	3.69	3.65	--	--	4.70	--	--	3.22
Diesel	3.95	4.47	--	--	4.77	--	--	3.59

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

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in coal use for electricity generation during this period and EIA projecting a stable outlook. IEA's projection for power sector coal consumption is available only for 2035 and is 7% higher than the AEO2014 Reference case. BP's projections are available only for 2025 and 2035; the 2035 projection is 17% lower than the AEO2014 Reference case projection. INFORUM, which has the highest projections for total coal consumption, did not supply projections for electricity sector coal use.

Projections of coal-fired generating capacity in Table CP4 underlie the projections for electricity sector coal consumption. For the most part, coal-fired generating capacity in the AEO2014, EVA, ICF, and IHSGI projections align with their respective levels of projected electricity sector coal consumption. The AEO2014 Reference case shows the highest level of coal-fired generating capacity in 2040 and IHSGI the lowest. In the AEO2014 Reference case, coal-fired generating capacity in the electric power sector declines from 307 GW in 2012 to 258 GW in 2040. ICF, EVA, and IHSGI project 243 GW, 202 GW, and 176 GW of coal-fired generating capacity, respectively, in 2040. In the AEO2014 Reference case, the 48-GW decline in coal-fired generating capacity from 2012 to 2040 is the net result of 51 GW of cumulative retirements and 3 GW of additions. IHSGI projects 146 GW of cumulative coal-fired generating capacity retirements from 2012 to 2040 and 10 GW of coal-fired capacity additions.

In all the projections, coal consumption in the end-use sectors is low in comparison with the electric power sector; however, there are some significant differences. The largest variations occur in the projections for the other industrial/buildings sector, where the AEO2014 projection is generally higher than the projections from the other groups, with the exception of INFORUM. While the AEO2014 Reference case shows a relatively flat outlook for coal consumption in the other industrial/buildings sector after rebounding from a low of 45 million tons in 2012, the other projections generally show significant declines from 2012 to 2025, with steady consumption levels thereafter. In 2040, the projections for coal consumption in the other industrial/buildings sector provided by EVA, ICF, and IHSGI range from a low of 7 million tons (ICF) to a high of 33 million tons (EVA), and all are considerably lower than the AEO2014 projection of 52 million tons.

The projections for coal consumption at coke plants are similar to AEO2014, which shows a slight decline in coking coal consumption, from 21 million tons in 2012 to 18 million tons in 2040. The largest deviation from AEO2014 is in the ICF projection, which shows

Table CP6. Comparisons of petroleum and other liquids projections, 2025, 2035, and 2040 (million barrels per day, except where noted) (continued)

Projection	2012	*AEO2014* Reference	BP[a,b]	EVA	INFORUM[c]	IEA[b]	ExxonMobil[c]	IHSGI
		2040						
U.S. refiner imported acquisition cost of crude oil (2012 dollars per barrel)	101.10	130.80	--	--	154.97	--	--	--
Brent spot price (2012 dollars per barrel)	111.65	141.46	--	--	171.16	--	--	--
U.S. WTI crude oil price (2012 dollars per barrel)	94.12	139.46	--	--	--	--	--	95.63
Domestic production	**8.89**	**10.46**	**--**	**--**	**--**	**--**	**--**	**10.88**
Crude oil	6.49	7.48	--	--	10.35	--	4.30	7.16
Alaska	0.53	0.26	--	--	--	--	--	--
Natural gas liquids	2.40	2.98	--	--	--	--	--	3.72
Total net imports	**7.52**	**5.93**	**--**	**--**	**6.80**	**--**	**--**	**6.16**
Crude oil	8.43	7.74	--	--	7.47	--	--	7.02
Products	-0.92	-1.82	--	--	-0.66	--	--	-0.86
Petroleum and other liquids consumption	18.49	18.73	--	--	18.16	--	17.96	19.56
Net petroleum import share of liquids supplied (percent)	40	32	--	--	--	--	--	32
Biofuel production	0.91	0.97	--	--	--	--	--	1.05
Transportation product prices (2012 dollars per gallon)								
Gasoline	3.69	3.90	--	--	5.14	--	--	3.20
Diesel	3.95	4.73	--	--	5.08	--	--	3.57

-- = not reported.

[a]BP production data converted from million tonnes of oil equivalent at 8.067817 bbl/MTOE.

[b]BP and IEA demand data converted from million tonnes of oil equivalent at 8.162674 bbl/MTOE.

[c]INFORUM and ExxonMobil liquids demand data converted from quadrillion Btu to barrels at 187.84572 million barrels per quadrillion Btu.

coal consumption at coke plants declining to 10 million tons in 2040. INFORUM, which provided projections only for total end-use sector coal consumption, shows slightly higher levels of coal use in these sectors than AEO2014 for all comparison years. ICF is the only group projecting any production of coal-based synthetic liquids, with coal consumption at coal-to-liquids plants increasing to 6 million tons in 2025 and 14 million tons in 2040.

For coal production, differences in the projections are primarily the result of differences in the outlooks for coal consumption and net exports (which basically equal total coal production when added together) [*3*]. Because the AEO2014 projections for net coal exports are generally similar to those from other groups, the percent differences in the projected levels of coal production between the AEO2014 Reference case and those from other groups generally align with the percent differences in the projections for coal consumption. The most substantial deviation is in the ICF outlook for 2040, where the ICF projection for coal production is 12% less than the AEO2014 Reference case, and the outlook for coal consumption is 21% less. ICF's projection for coal production in 2040 is supported by a relatively strong outlook for net coal exports at 205 million tons, which is 28% higher than in AEO2014.

Coal production by region is available in the AEO2014, EVA, and ICF projections. For the most part, the EVA and ICF projections of regional coal production are less than in AEO2014. This is consistent with the generally lower projections for total coal production in the EVA and ICF outlooks. Although the shares of coal production by region remain relatively constant in AEO2014, with coal production east of the Mississippi River accounting for between 40% and 42% of total coal production in all years, the EVA projection shows the region's share of total U.S. coal production fall from 42% in 2012 to 35% in 2040, and ICF projects an increase to 49% in 2040.

In the AEO2014 Reference case, exports increase gradually from 126 million tons in 2012 to 160 million tons in 2035 and remain flat through 2040, maintaining 12% to 14% shares of total U.S. coal production over time. The EVA projection shows exports growing modestly, to 135 million tons in 2025, then remaining flat through 2040 and maintaining a share of total U.S. production similar to that in the AEO2014 projection. Exports in the IHSGI outlook are similar to those in the AEO2014 Reference case, but the share of total U.S. production in 2040 is much higher, at 22%, because of a projected significant reduction in total U.S. production. After a modest decrease from 2012 to 2025, the ICF projection shows exports recover more than in the other projections—to 206 million tons, or 21% of total U.S. coal production. Exports in the INFORUM outlook are similar to those in the ICF projection for 2040, although they represent only 13% of their stronger expected total U.S. coal production.

Table CP7. Comparisons of coal projections, 2025, 2035, and 2040 (million short tons, except where noted)

		AEO2014 Reference case		Other projections					
		(million short tons)	(quadrillion Btu)	EVA[a]	ICF[b]	IHSGI[c]	INFORUM	IEA[d]	BP[d]
Projection	2012			(million short tons)				(quadrillion Btu)	
		2025							
Production	**1,016**	**1,114**	**22.36**	**1,111**	**1,005**	**970**	**1,253**	**--**	**18.9**
East of the Mississippi	423	446	--	435	377	--	--	--	--
West of the Mississippi	593	668	--	676	628	--	--	--	--
Consumption									
Electric power	825	919	17.41	937	867	771	--	--	16.4
Coke plants	21	22	0.58	21	12	19	--	--	--
Coal-to-liquids	--	--	--	--	6	--	--	--	--
Other industrial/buildings	45	51	1.63[e]	36	8	38	1.69[e]	--	--
Total consumption (quadrillion Btu)	**17.34**	**--**	**19.03**	**--**		**16.41**	**--**	**--**	**17.3**
Total consumption (million short tons)	**891**	**993**	**--**	**994**	**893**	**828**	**1,117[f]**	**--**	**--**
Net coal exports	**118**	**135**	**3.27**	**--**	**110**	**142**	**136**	**--**	**1.6[g]**
Exports	126	136	--	135	111	144	140	--	--
Imports	8	2	--	--	1	2	4	--	--
Minemouth price									
2012 dollars per ton	39.94	49.67	--	--	31.94	--	44.93	--	--
2012 dollars per Btu	1.98	2.49	--	--	1.60	--	2.26	--	--
Average delivered price to electricity generators									
2012 dollars per ton	46.13	52.56	--	--	42.33	50.77	--	--	--
2012 dollars per Btu	2.39	2.77	--	--	2.17	2.59	--	--	--

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

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In the AEO2014, ICF, and IHSGI projections, coal imports decline from 8 million tons in 2012 to 2 million tons or less in 2025 and remain at that level through 2040. INFORUM projects an initial decline in coal imports, to 4 million tons in 2025, followed by an increase to 34 million tons in 2040. EVA, IEA, and BP did not provide projections for coal imports.

Only AEO2014, ICF, and INFORUM provide projections of minemouth coal prices. All three show prices increasing from 2025 through 2040. The AEO2014 Reference case projects the highest mine prices in every comparison year, with the average price rising from about $40/ton in 2012 to $59/ton in 2040. The ICF outlook has the lowest projections, with prices declining initially to about $32/ton in 2025 and increasing thereafter to $37/ton in 2040. In the INFORUM projection, average minemouth coal prices increase to $52/ton in 2040.

Projections for the average delivered price of coal to the electricity sector are available only from AEO2014, ICF, and IHSGI. Similarly to the projections for minemouth coal prices, AEO2014 projects the highest delivered coal prices in every comparison year. In the AEO2014 Reference case, the delivered price of coal to the power sector increases from about $46/ton in 2012 to $61/ton in 2040. By comparison, the ICF price projections are the lowest in each year, with a 2040 projection of $44/ton, or 27% less than in the AEO2014 Reference case. In the IHSGI projection, the delivered price of coal to the power sector increases to $52/ton in 2040, or 15% below the AEO2014 Reference case projection.

Table CP7. Comparisons of coal projections, 2025, 2035, and 2040 (million short tons, except where noted) (continued)

		AEO2014 Reference case		Other projections					
				EVA[a]	ICF[b]	IHSGI[c]	INFORUM	IEA[d]	BP[d]
Projection	2012	(million short tons)	(quadrillion Btu)	(million short tons)				(quadrillion Btu)	
		2035							
Production	**1,016**	**1,126**	**22.68**	**1,084**	**1,004**	**837**	**1,386**	**--**	**16.3**
East of the Mississippi	423	471	--	414	427	--	--	--	--
West of the Mississippi	593	655	--	670	577	--	--	--	--
Consumption									
Electric power	825	915	17.32	910	820	637	--	18.57	14.4
Coke plants	21	19	0.50	21	11	18	--	--	--
Coal-to-liquids	--	--	--	--	11	--	--	--	--
Other industrial/buildings	45	51	1.54[e]	34	7	33	1.61[e]	--	--
Total consumption (quadrillion Btu)	**17.34**	**--**	**18.82**	**--**		**13.56**	**--**	**20.87**	**15.2**
Total consumption (million short tons)	**891**	**985**	**--**	**965**	**849**	**688**	**1,232[f]**	**--**	**--**
Net coal exports	**118**	**158**	**3.76**	**--**	**153**	**151**	**154**	**--**	**1.1[g]**
Exports	126	160	--	137	154	153	173	--	--
Imports	8	2	--	--	1	2	20	--	--
Minemouth price									
2012 dollars per ton	39.94	56.37	--	--	33.55	--	50.10	--	--
2012 dollars per Btu	1.98	2.82	--	--	1.66	--	2.52	--	--
Average delivered price to electricity generators									
2012 dollars per ton	46.13	57.76	--	--	42.92	52.93	--	--	--
2012 dollars per Btu	2.39	3.05	--	--	2.19	2.72	--	--	--

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

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Table CP7. Comparisons of coal projections, 2025, 2035, and 2040 (million short tons, except where noted) (continued)

Projection	2012	*AEO2014* Reference case (million short tons)	*AEO2014* Reference case (quadrillion Btu)	Other projections: EVA[a]	ICF[b]	IHSGI[c]	INFORUM	IEA[d]	BP[d]
				(million short tons)				(quadrillion Btu)	
		2040							
Production	1,016	1,121	22.61	938	981	703	1,451	--	--
East of the Mississippi	423	475	--	331	481	--	--	--	--
West of the Mississippi	593	645	--	607	500	--	--	--	--
Consumption									
Electric power	825	909	17.27	764	742	506	--	--	--
Coke plants	21	18	0.47	22	10	17	--	--	--
Coal-to-liquids	--		--	--	14	--	--	--	--
Other industrial/buildings	45	52	1.53[e]	33	7	30	1.66[e]	--	--
Total consumption (quadrillion Btu)	**17.34**	**--**	**18.75**	**--**	**--**	**10.75**	**--**	**--**	**--**
Total consumption (million short tons)	**891**	**979**	**--**	**819**	**773**	**553**	**1,294**[f]	**--**	**--**
Net coal exports (million short tons)	**118**	**160**	**3.76**	**--**	**205**	**154**	**157**	**--**	**--**
Exports	126	161	--	137	206	156	191	--	--
Imports	8	1	--	--	1	2	34	--	--
Minemouth price									
2012 dollars per ton	39.94	59.16	--	--	36.58	--	52.20	--	--
2012 dollars per Btu	1.98	2.96	--	--	1.76	--	2.63	--	--
Average delivered price to electricity generators									
2012 dollars per ton	46.13	60.61	--	--	43.96	51.76	--	--	--
2012 dollars per Btu	2.39	3.19	--	--	2.22	2.71	--	--	--

-- = not reported.

[a]Regulations known to be accounted for in the EVA projections include MATS, carbon pollution standard for new plants, 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 (Hg), hydrochloric acid (HCl), and filterable particulate matter (fPM) requirements starting in 2016, Phase I and II for CAIR followed by a more stringent CAIR replacement in 2018 to address 2012 National Ambient Air Quality Standards (NAAQS) for PM2.5, carbon pollution standard for new plants, entrainments requirements for cooling water intake structures beginning in 2025, coal combustion residual requirements under subtitle D starting in 2018, and a federal carbon cap-and-trade program starting in 2023.

[c]The IHSGI projections include a CO2 cap-and-trade program for the electricity sector that begins in 2021 and a CO2 allowance price that increases to $20 per metric ton (2012 dollars) in 2040.

[d]For IEA and BP, data were converted to quadrillion Btu from million metric tons of oil equivalent using a conversion factor of 39.683 million Btu per metric ton of oil equivalent.

[e]Reported in quadrillion Btu and represents coal consumed in both the other industrial/buildings sector and at coke plants. This was done to facilitate comparison between the AEO2014 and INFORUM projections, because INFORUM provided projections only for total end-use coal consumption.

[f]Total coal consumption for the INFORUM projection equals (production - exports + imports).

[g]Net coal exports for the BP projection equals (production - consumption).

Endnotes for Comparison with other projections

Links current as of April 2014

1. ExxonMobil Corporation, "The Outlook for Energy: A View to 2040" (Irving, TX, 2013), http://cdn.exxonmobil.com/~/media/Reports/Outlook%20For%20Energy/2014/2014-Outlook-for-Energy.pdf; and W. Colton, "The Outlook for Energy: A View to 2040" (Irving, TX, December 12, 2013), http://cdn.exxonmobil.com/~/media/Reports/Outlook%20For%20Energy/2014/ExxonMobil_2014_Outlook-for-Energy_Rollout_Presentation.pdf.
2. E-mail on February 10, 2014 from Margaret Rhodes of IHS Global Insight.
3. For the AEO2014 Reference case, waste coal is counted as part of overall coal consumption but is not counted as part of coal production. Rather, waste coal is considered to be a separate source of coal supply. As a result, the AEO2014 Reference case projection of coal production in tons equals coal consumption plus net exports minus waste coal.

Table sources

Links current as of April 2014

Table CP1. Comparisons of average annual economic growth projections, 2012-40: AEO2014 (Reference case): AEO2014 National Energy Modeling System, run REF2014.D102413A. **AEO2013 (Reference case):** AEO2013 National Energy Modeling System, run REF2013.D102312A. **IHSGI:** IHS Global Insight, 30-year U.S. Economic Forecast (Lexington, MA, October 2013), http://www.ihs.com/products/global-insight/index.aspx (subscription site). **OMB:** Office of Management and Budget, Budget of the United States Government, Fiscal Year 2015 (Washington, DC, January 2014), http://www.whitehouse.gov/sites/default/files/omb/budget/fy2015/assets/budget.pdf. **CBO:** Congressional Budget Office, *The Budget and Economic Outlook: 2014 to 2024* (Washington, DC, February 2014), http://www.cbo.gov/publication/45010. **INFORUM:** *INFORUM AEO2012 Reference Case, Lift (Long-term Interindustry Forecasting Tool) Model* (College Park, MD, January 2014), http://inforumweb.umd.edu/services/models/lift.html. **SSA:** Social Security Administration, OASDI Trustees Report, *The Long-Range Economic Assumptions for the 2013 Trustees Report* (U.S. Government Printing Office, Washington, DC, May 2013), http://www.ssa.gov/oact/tr/2013/2013_Long-Range_Economic_Assumptions.pdf. **IEA (2013):** International Energy Agency, *World Energy Outlook 2013* (Paris, France, November 2013), http://www.iea.org/Textbase/nppdf/stud/13/weo2013.pdf. **ExxonMobil:** *ExxonMobil 2014 The Outlook for Energy: A View to 2040* (Irving, TX, 2013), http://www.exxonmobil.com/Corporate/energy_outlook.aspx. **OEG:** Oxford Economics, Ltd., 2014 Long Term Forecast (Oxford, United Kingdom, January 2014), http://www.OxfordEconomics.com (subscription site).

Table CP2. Comparisons of oil price projections, 2025, 2035, and 2040: AEO2014 (Reference case): AEO2014 National Energy Modeling System, run REF2014.D102413A. **AEO2014 (Low Oil Price case):** AEO2014 National Energy Modeling System, run LOWPRICE.D120613. **AEO2014 (High Oil Price case):** AEO2014 National Energy Modeling System, run HIGHPRICE.D120613A. **AEO2013 (Reference case):** AEO2013 National Energy Modeling System, run REF2013.D102312A. **Energy SEER:** Strategic Energy & Economic Research, Inc., e-mail from Michael Lynch (Amherst, MA, January 2014). **ArrowHead Economics:** ArrowHead Economics LLC, e-mail from Dale Nesbitt (Los Altos Hills, CA, January 2014), www.arrowheadeconomics.com. **EVA:** Energy Ventures Analysis, Inc., e-mail from Anthony Petruzzo, January 17, 2014. **INFORUM:** *INFORUM AEO2012 Reference Case, Lift (Long-term Interindustry Forecasting Tool) Model* (College Park, MD, January 2014), http://inforumweb.umd.edu/services/models/lift.html. **ESAI:** Energy Security Analysis, Inc., e-mail from Sarah Emerson (Wakefield, MA, March 2014), www.esai.com. **IEA (Current Policies Scenario):** International Energy Agency, *World Energy Outlook 2013* (Paris, France, November 2013), http://www.iea.org/Textbase/nppdf/stud/13/weo2013.pdf.

Table CP3. Comparisons of energy consumption projections by sector, 2025, 2035, and 2040: AEO2014 (Reference case): AEO2014 National Energy Modeling System, run REF2014.D102413A. **INFORUM:** *INFORUM AEO2012 Reference Case, Lift (Long-term Interindustry Forecasting Tool) Model* (College Park, MD, January 2014), http://inforumweb.umd.edu/services/models/lift.html. **IHSGI:** IHS Global Insight, 30-year U.S. Economic Forecast (Lexington, MA, October 2013), http://www.ihs.com/products/global-insight/index.aspx (subscription site). **ExxonMobil:** *ExxonMobil 2014 The Outlook for Energy: A View to 2040* (Irving, TX, 2013), http://www.exxonmobil.com/Corporate/energy_outlook.aspx. **IEA (Current Policies Scenario):** International Energy Agency, *World Energy Outlook 2013* (Paris, France, November 2013), http://www.iea.org/Textbase/nppdf/stud/13/weo2013.pdf.

Table CP4. Comparisons of electricity projections, 2025, 2035, and 2040: AEO2014 (Reference case): AEO2014 National Energy Modeling System, run REF2014.D102413A. **EVA:** Energy Ventures Analysis, Inc., e-mail from Anthony Petruzzo, January 17, 2014. **IHSGI:** IHS Global Insight, 30-year U.S. Economic Forecast (Lexington, MA, October 2013), 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, January 2014), http://inforumweb.umd.edu/services/models/lift.html. **ICF:** *ICF International Integrated Energy Outlook Q1 2014,* ICF Integrated Planning Model (IPM) and Gas Market Model (GMM) (Fairfax, VA, 1st Quarter 2014.

Table CP5. Comparisons of natural gas projections, 2025, 2035, and 2040: AEO2014 (Reference case): AEO2014 National Energy Modeling System, run REF2014.D102413A. **IHSGI:** IHS Global Insight, 30-year U.S. Economic Forecast (Lexington, MA, October 2013), http://www.ihs.com/products/global-insight/index.aspx (subscription site). **EVA:** Energy Ventures Analysis, Inc., e-mail from Anthony Petruzzo, January 17, 2014. **ICF:** *ICF International Integrated Energy Outlook Q1 2014,* ICF Integrated Planning Model (IPM) and Gas Market Model (GMM) (Fairfax, VA, 1st Quarter 2014. **BP:** BP, p.l.c., e-mail from Mark J. Finley, January 17, 2014. **ExxonMobil:** *ExxonMobil 2014 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, January 2014), http://inforumweb.umd.edu/services/models/lift.html.

Table CP6. Comparisons of petroleum and other liquids projections, 2025, 2035, and 2040: AEO2014 (Reference case): AEO2014 National Energy Modeling System, run REF2014.D102413A. **BP:** BP, p.l.c., e-mail from Mark J. Finley, January 17, 2014. **EVA:** Energy Ventures Analysis, Inc., e-mail from Anthony Petruzzo, January 17, 2014. **INFORUM:** *INFORUM AEO2012 Reference Case, Lift (Long-term Interindustry Forecasting Tool) Model* (College Park, MD, January 2014), http://inforumweb.umd.edu/services/models/lift.html. **IEA (Current Policies Scenario):** International Energy Agency, *World Energy Outlook 2013* (Paris, France, November 2013), http://www.iea.org/Textbase/nppdf/stud/13/weo2013.pdf. **ExxonMobil:** *ExxonMobil 2014 The Outlook for Energy: A View to 2040* (Irving, TX, 2013), http://www.exxonmobil.com/Corporate/energy_outlook.aspx. **IHSGI:** IHS Global Insight, 30-year U.S. Economic Forecast (Lexington, MA, October 2013), http://www.ihs.com/products/global-insight/index.aspx (subscription site).

Table CP7. Comparisons of coal projections, 2025, 2035, and 2040: AEO2014 (Reference case): AEO2014 National Energy Modeling System, run REF2014.D102413A. **EVA:** Energy Ventures Analysis, Inc., e-mail from Anthony Petruzzo, January 17, 2014. **ICF:** *ICF International Integrated Energy Outlook Q1 2014,* ICF Integrated Planning Model (IPM) and Gas Market Model (GMM) (Fairfax, VA, 1st Quarter 2014. **IHSGI:** IHS Global Insight, 30-year U.S. Economic Forecast (Lexington, MA, October 2013), 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, January 2014), http://inforumweb.umd.edu/services/models/lift.html. **IEA (Current Policies Scenario):** International Energy Agency, *World Energy Outlook 2013* (Paris, France, November 2013), http://www.iea.org/Textbase/nppdf/stud/13/weo2013.pdf. **BP:** BP, p.l.c., e-mail from Mark J. Finley, January 17, 2014.

List of acronyms

AB 32	California Assembly Bill 32, the Global Warming Solutions Act of 2006
AC	Alternating current
ACP	Alternative compliance payment
AEO	Annual Energy Outlook
AEO2012	Annual Energy Outlook 2012
AEO2013	Annual Energy Outlook 2013
AEO2014	Annual Energy Outlook 2014
ARRA2009	American Recovery and Reinvestment Act of 2009
AZNM	Arizona, New Mexico, and Nevada
Bcf	Billion cubic feet
BP	BP, p.l.c.
BTL	Biomass-to-liquids
BNSF	Burlington Northern Santa Fe
BWRs	Boiling water reactors
Btu	British thermal units
BEA	Bureau of Economic Analysis
Bu16	Biobutanol blends with 16% biobutanol and 84% gasoline
CAFE	Corporate average fuel economy
CAIR	Clean Air Interstate Rule
CAMX	WECC California
CBO	Congressional Budget Office
CBTL	Coal- and biomass-to-liquids
CCS	Carbon capture and storage
CEUS	Central and Eastern United States
CFL	Compact fluorescent lighting
CHP	Combined heat and power
CMM	Coal Market Module
CNG	Compressed natural gas
COL	Combined operating license
CO_2	Carbon dioxide
CO_2-EOR	Carbon dioxide-enhanced oil recovery
CSAPR	Cross-State Air Pollution Rule
CTL	Coal-to-liquids
DC	Direct current
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
ESICA	Energy Savings and Industrial Competitiveness Act of 2013
EIEA2008	Energy Improvement and Extension Act of 2008
EISA2007	Energy Independence and Security Act of 2007
EPACT2005	Energy Policy Act of 2005
EPRI	Electric Power Research Institute
EMM	Electricity Market Module
EPA	U.S. Environmental Protection Agency
EPACT2005	Energy Policy Act of 2005
ESAI	Energy Security Analysis
EUR	Estimated ultimate recovery
EVA	Energy Ventures Analysis
FCC	Fluid catalytic cracking
FEMA	Federal Emergency Management Administration
FFV	Flex-fuel vehicle
FGD	Flue gas desulfurization (scrubbers)
FRA	Federal Railroad Administration
Gal	Gallons
GDP	Gross domestic product
GHG	Greenhouse gas
GTL	Gas-to-liquids
GVWR	Gross vehicle weight rating
GW	Gigawatts
HDV	Heavy-duty vehicle
HGL	Hydrocarbon gas liquids
Hg	Mercury
HPDI	High-pressure direct injection
ICF	ICF International, Incorporated
IDM	Industrial Demand Module
IEA	International Energy Agency
IEM	International Energy Module
IGCC	Integrated gasification combined cycle
IHSGI	IHS Global Insight, Inc.
INFORUM	Interindustry Forecasting Project at the University of Maryland
INPO	Institute for Nuclear Power Operations
IRAC	U.S. imported refiner acquisition cost
ITC	Investment tax credit
KW	Kilowatt
kWh	Kilowatthours
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
MACT	Maximum achievable control technology
Mcf	Thousand cubic feet
MW	Megawatts
MWh	Megawatthours
MATS	Mercury and Air Toxics Standards
MAM	Macroeconomic Activity Module
Mpg	Miles per gallon
MMbbl/d	Million barrels per day
MMBtu	Million British thermal units
MRO	Midwest Reliability Organization
MMmt	Million metric tons
MY	Model year
MSW	Municipal solid waste
NAICS	North American Industry Classification System
NEMS	National Energy Modeling System
NERC	North American Electric Reliability Corporation
NGCC	Natural gas combined-cycle
NGPL	Natural gas plant liquids
NGTDM	Natural Gas Transmission and Distribution Module
NHTSA	National Highway Traffic Safety Administration
NIPA	National Income and Product Accounts
NO_X	Nitrogen oxides
NRC	U.S. Nuclear Regulatory Commission
O&M	Operations and maintenance
OECD	Organization for Economic Cooperation and Development

List of acronyms (continued)

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
PTC	Production tax credit
PV	Solar photovoltaic
RGGI	Regional Greenhouse Gas Initiative
RFM	Renewable Fuels Module
RFS	Renewable fuel standard
RPS	Renewable portfolio standard
R&D	Research and development
RFC	ReliabilityFirst Corporation
RTO	Regional Transmission Organization
SEER	Strategic Energy & Economic Research
SERC	SERC Reliability Corporation
SO_2	Sulfur dioxide
SSA	Social Security Administration
SRVC	Virginia, North Carolina, and South Carolina
STEO	Short-Term Energy Outlook
TRE	Texas Reliability Entity
Tcf	Trillion cubic feet
VMT	Vehicle miles traveled
WECC	Western Electricity Coordinating Council
WTI	West Texas Intermediate
WUS	Western United States

Table A1. Total energy supply, disposition, and price summary
(quadrillion Btu per year, unless otherwise noted)

Supply, disposition, and prices	Reference case							Annual growth 2012-2040 (percent)
	2011	2012	2020	2025	2030	2035	2040	
Production								
Crude oil and lease condensate	12.20	13.87	20.36	19.19	17.71	16.81	16.00	0.5%
Natural gas plant liquids	3.11	3.21	3.54	3.84	3.98	4.08	3.99	0.8%
Dry natural gas	23.04	24.59	29.73	32.57	35.19	36.89	38.37	1.6%
Coal[1]	22.22	20.60	21.70	22.36	22.61	22.68	22.61	0.3%
Nuclear / uranium[2]	8.26	8.05	8.15	8.15	8.18	8.23	8.49	0.2%
Hydropower	3.11	2.67	2.81	2.84	2.87	2.89	2.90	0.3%
Biomass[3]	3.90	3.78	4.66	5.08	5.29	5.44	5.61	1.4%
Other renewable energy[4]	1.70	1.97	3.01	3.09	3.23	3.44	3.89	2.5%
Other[5]	0.80	0.41	0.24	0.24	0.24	0.24	0.24	-2.0%
Total	**78.35**	**79.15**	**94.19**	**97.36**	**99.30**	**100.70**	**102.09**	**0.9%**
Imports								
Crude oil	19.52	18.57	13.15	13.70	15.00	16.12	17.43	-0.2%
Petroleum and other liquids[6]	5.21	4.26	4.21	4.20	4.08	4.00	3.93	-0.3%
Natural gas[7]	3.56	3.21	2.39	2.04	2.01	2.06	2.28	-1.2%
Other imports[8]	0.43	0.36	0.17	0.15	0.12	0.11	0.10	-4.5%
Total	**28.71**	**26.40**	**19.92**	**20.09**	**21.22**	**22.29**	**23.73**	**-0.4%**
Exports								
Petroleum and other liquids[9]	5.95	6.29	6.30	6.48	6.91	7.40	7.70	0.7%
Natural gas[10]	1.52	1.63	4.30	5.45	6.96	7.60	8.09	5.9%
Coal	2.75	3.22	3.13	3.31	3.55	3.81	3.79	0.6%
Total	**10.22**	**11.14**	**13.73**	**15.24**	**17.42**	**18.81**	**19.58**	**2.0%**
Discrepancy[11]	**-0.27**	**-0.61**	**-0.35**	**-0.24**	**-0.17**	**-0.11**	**-0.07**	**- -**
Consumption								
Petroleum and other liquids[12]	36.56	35.87	36.86	36.28	35.65	35.37	35.35	-0.1%
Natural gas	24.91	26.20	27.65	28.97	30.03	31.10	32.32	0.8%
Coal[13]	19.62	17.34	18.56	19.03	19.01	18.82	18.75	0.3%
Nuclear / uranium[2]	8.26	8.05	8.15	8.15	8.18	8.23	8.49	0.2%
Hydropower	3.11	2.67	2.81	2.84	2.87	2.89	2.90	0.3%
Biomass[14]	2.60	2.53	3.35	3.74	3.95	4.10	4.26	1.9%
Other renewable energy[4]	1.70	1.97	3.01	3.09	3.23	3.44	3.89	2.5%
Other[15]	0.35	0.39	0.34	0.35	0.35	0.33	0.35	-0.4%
Total	**97.11**	**95.02**	**100.73**	**102.45**	**103.27**	**104.28**	**106.31**	**0.4%**
Prices (2012 dollars per unit)								
Crude oil spot prices (dollars per barrel)								
Brent	113.24	111.65	96.57	108.99	118.99	129.77	141.46	0.8%
West Texas Intermediate	96.55	94.12	94.57	106.99	116.99	127.77	139.46	1.4%
Natural gas at Henry Hub (dollars per million Btu)	4.07	2.75	4.38	5.23	6.03	6.92	7.65	3.7%
Coal (dollars per ton)								
at the minemouth[16]	41.74	39.94	46.52	49.67	53.15	56.37	59.16	1.4%
Coal (dollars per million Btu)								
at the minemouth[16]	2.07	1.98	2.33	2.49	2.67	2.82	2.96	1.4%
Average end-use[17]	2.61	2.60	2.85	3.02	3.17	3.29	3.43	1.0%
Average electricity (cents per kilowatthour)	10.1	9.8	10.1	10.1	10.4	10.7	11.1	0.4%

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 2012-2040 (percent)
	2011	2012	2020	2025	2030	2035	2040	
Prices (nominal dollars per unit)								
Crude oil spot prices (dollars per barrel)								
Brent	111.26	111.65	109.37	134.25	160.19	193.27	234.53	2.7%
West Texas Intermediate	94.86	94.12	107.11	131.78	157.49	190.30	231.22	3.3%
Natural gas at Henry Hub (dollars per million Btu)	4.00	2.75	4.96	6.45	8.12	10.31	12.69	5.6%
Coal (dollars per ton)								
at the minemouth[16]	41.01	39.94	52.69	61.18	71.55	83.96	98.08	3.3%
Coal (dollars per million Btu)								
at the minemouth[16]	2.04	1.98	2.63	3.07	3.59	4.21	4.91	3.3%
Average end-use[17]	2.56	2.60	3.23	3.72	4.27	4.90	5.68	2.8%
Average electricity (cents per kilowatthour)	9.9	9.8	11.5	12.5	14.0	16.0	18.5	2.3%

[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]Estimated consumption. 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 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 2011 and 2012 are model results and may differ from official EIA data reports.
Sources: 2011 natural gas supply values: U.S. Energy Information Administration (EIA), *Natural Gas Annual 2011*, DOE/EIA-0131(2011) (Washington, DC, December 2012). 2012 natural gas supply values: EIA, *Natural Gas Monthly*, DOE/EIA-0130(2013/06) (Washington, DC, June 2013). 2011 and 2012 coal minemouth and delivered coal prices: EIA, *Annual Coal Report 2012*, DOE/EIA-0584(2012) (Washington, DC, December 2013). 2012 petroleum supply values and 2011 crude oil and lease condensate production: EIA, *Petroleum Supply Annual 2012*, DOE/EIA-0340(2012)/1 (Washington, DC, September 2013). Other 2011 petroleum supply values: EIA, *Petroleum Supply Annual 2011*, DOE/EIA-0340(2011)/1 (Washington, DC, August 2012). 2011 and 2012 crude oil spot prices and natural gas spot price at Henry Hub: Thomson Reuters. Other 2011 and 2012 coal values: *Quarterly Coal Report, October-December 2012*, DOE/EIA-0121(2012/4Q) (Washington, DC, March 2013). Other 2011 and 2012 values: EIA, *Monthly Energy Review*, DOE/EIA-0035(2013/09) (Washington, DC, September 2013). **Projections:** EIA, AEO2014 National Energy Modeling System run REF2014.D102413A.

Table A2. Energy consumption by sector and source
(quadrillion Btu per year, unless otherwise noted)

Sector and source	Reference case							Annual growth 2012-2040 (percent)
	2011	2012	2020	2025	2030	2035	2040	
Energy consumption								
Residential								
Propane	0.51	0.51	0.42	0.40	0.38	0.36	0.35	-1.3%
Kerosene	0.02	0.01	0.00	0.00	0.00	0.00	0.00	-2.5%
Distillate fuel oil	0.53	0.51	0.46	0.41	0.37	0.34	0.31	-1.7%
Petroleum and other liquids subtotal	1.05	1.02	0.89	0.82	0.75	0.70	0.66	-1.5%
Natural gas	4.82	4.26	4.56	4.50	4.43	4.32	4.21	0.0%
Renewable energy[1]	0.54	0.45	0.46	0.45	0.44	0.43	0.42	-0.3%
Electricity	4.85	4.69	4.84	5.00	5.21	5.41	5.65	0.7%
Delivered energy	**11.26**	**10.42**	**10.74**	**10.77**	**10.83**	**10.86**	**10.94**	**0.2%**
Electricity related losses	10.13	9.68	9.64	9.81	10.00	10.22	10.55	0.3%
Total	**21.39**	**20.10**	**20.38**	**20.58**	**20.83**	**21.09**	**21.48**	**0.2%**
Commercial								
Propane	0.15	0.15	0.16	0.16	0.17	0.17	0.18	0.7%
Motor gasoline[2]	0.05	0.05	0.04	0.05	0.05	0.05	0.05	0.6%
Kerosene	0.00	0.00	0.00	0.00	0.00	0.00	0.00	4.8%
Distillate fuel oil	0.42	0.40	0.40	0.39	0.38	0.37	0.37	-0.3%
Residual fuel oil	0.05	0.04	0.08	0.08	0.08	0.08	0.08	2.4%
Petroleum and other liquids subtotal	0.67	0.63	0.68	0.68	0.67	0.67	0.68	0.2%
Natural gas	3.22	2.96	3.23	3.29	3.35	3.48	3.65	0.7%
Coal	0.06	0.04	0.04	0.04	0.04	0.04	0.04	0.0%
Renewable energy[3]	0.11	0.13	0.13	0.13	0.13	0.13	0.13	0.0%
Electricity	4.53	4.52	4.69	4.94	5.18	5.42	5.72	0.8%
Delivered energy	**8.60**	**8.29**	**8.78**	**9.08**	**9.38**	**9.75**	**10.22**	**0.7%**
Electricity related losses	9.46	9.32	9.34	9.69	9.94	10.24	10.66	0.5%
Total	**18.05**	**17.61**	**18.12**	**18.77**	**19.32**	**19.99**	**20.88**	**0.6%**
Industrial[4]								
Liquefied petroleum gases and other[5]	2.25	2.25	2.90	3.05	3.05	2.97	2.90	0.9%
Motor gasoline[2]	0.26	0.26	0.30	0.30	0.30	0.29	0.29	0.4%
Distillate fuel oil	1.24	1.20	1.40	1.41	1.41	1.41	1.42	0.6%
Residual fuel oil	0.13	0.10	0.14	0.14	0.15	0.15	0.15	1.4%
Petrochemical feedstocks	0.88	0.75	1.27	1.52	1.62	1.62	1.59	2.7%
Other petroleum[6]	3.36	3.50	3.56	3.53	3.58	3.63	3.75	0.2%
Petroleum and other liquids subtotal	8.13	8.06	9.56	9.95	10.10	10.08	10.10	0.8%
Natural gas	7.06	7.29	8.26	8.59	8.71	8.78	8.87	0.7%
Natural-gas-to-liquids heat and power	0.00	0.00	0.00	0.00	0.00	0.00	0.00	- -
Lease and plant fuel[7]	1.35	1.45	1.77	1.99	2.16	2.29	2.41	1.8%
Natural gas subtotal	8.41	8.75	10.04	10.58	10.87	11.07	11.28	0.9%
Metallurgical coal	0.56	0.55	0.58	0.58	0.55	0.50	0.47	-0.5%
Other industrial coal	0.95	0.93	0.99	1.00	1.00	1.00	1.01	0.3%
Coal-to-liquids heat and power	0.00	0.00	0.00	0.00	0.00	0.00	0.00	- -
Net coal coke imports	0.01	0.00	0.00	-0.01	-0.03	-0.05	-0.05	- -
Coal subtotal	1.53	1.48	1.57	1.57	1.52	1.45	1.44	-0.1%
Biofuels heat and coproducts	0.46	0.52	0.76	0.79	0.79	0.79	0.79	1.5%
Renewable energy[8]	1.49	1.48	1.74	1.88	2.01	2.13	2.28	1.6%
Electricity	3.38	3.35	4.04	4.27	4.33	4.32	4.34	0.9%
Delivered energy	**23.40**	**23.63**	**27.71**	**29.05**	**29.62**	**29.84**	**30.22**	**0.9%**
Electricity related losses	7.06	6.91	8.05	8.38	8.33	8.16	8.10	0.6%
Total	**30.46**	**30.54**	**35.76**	**37.43**	**37.94**	**38.00**	**38.33**	**0.8%**

Table A2. Energy consumption by sector and source (continued)
(quadrillion Btu per year, unless otherwise noted)

Sector and source	Reference case							Annual growth 2012-2040 (percent)
	2011	2012	2020	2025	2030	2035	2040	
Transportation								
Propane	0.05	0.05	0.05	0.05	0.06	0.06	0.07	1.1%
Motor gasoline[2]	16.37	16.33	15.00	13.69	12.69	12.24	12.09	-1.1%
of which: E85[9]	0.00	0.01	0.19	0.38	0.46	0.43	0.33	11.9%
Jet fuel[10]	3.01	3.00	3.08	3.14	3.20	3.24	3.28	0.3%
Distillate fuel oil[11]	6.04	5.82	6.70	7.04	7.25	7.44	7.54	0.9%
Residual fuel oil	0.78	0.58	0.58	0.59	0.59	0.60	0.60	0.2%
Other petroleum[12]	0.16	0.15	0.15	0.15	0.15	0.15	0.15	0.1%
Petroleum and other liquids subtotal	26.40	25.93	25.55	24.66	23.94	23.73	23.73	-0.3%
Pipeline fuel natural gas	0.70	0.73	0.74	0.76	0.82	0.83	0.85	0.5%
Compressed / liquefied natural gas	0.04	0.04	0.08	0.14	0.28	0.48	0.86	11.3%
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	0.05	0.06	3.6%
Delivered energy	**27.16**	**26.72**	**26.40**	**25.60**	**25.08**	**25.10**	**25.50**	**-0.2%**
Electricity related losses	0.05	0.05	0.06	0.07	0.08	0.10	0.12	3.2%
Total	**27.21**	**26.77**	**26.47**	**25.67**	**25.17**	**25.20**	**25.62**	**-0.2%**
Delivered energy consumption for all sectors								
Liquefied petroleum gases and other[5]	2.95	2.96	3.53	3.67	3.65	3.56	3.49	0.6%
Motor gasoline[2]	16.67	16.64	15.34	14.04	13.04	12.59	12.44	-1.0%
of which: E85[9]	0.00	0.01	0.19	0.38	0.46	0.43	0.33	11.9%
Jet fuel[10]	3.01	3.00	3.08	3.14	3.20	3.24	3.28	0.3%
Kerosene	0.03	0.01	0.01	0.01	0.01	0.01	0.01	0.9%
Distillate fuel oil	8.23	7.93	8.95	9.24	9.41	9.56	9.63	0.7%
Residual fuel oil	0.97	0.72	0.80	0.81	0.82	0.82	0.83	0.5%
Petrochemical feedstocks	0.88	0.75	1.27	1.52	1.62	1.62	1.59	2.7%
Other petroleum[13]	3.52	3.64	3.70	3.68	3.73	3.78	3.89	0.2%
Petroleum and other liquids subtotal	36.25	35.64	36.68	36.10	35.47	35.18	35.17	0.0%
Natural gas	15.14	14.56	16.14	16.52	16.77	17.07	17.59	0.7%
Natural-gas-to-liquids heat and power	0.00	0.00	0.00	0.00	0.00	0.00	0.00	- -
Lease and plant fuel[7]	1.35	1.45	1.77	1.99	2.16	2.29	2.41	1.8%
Pipeline fuel natural gas	0.70	0.73	0.74	0.76	0.82	0.83	0.85	0.5%
Natural gas subtotal	17.19	16.74	18.65	19.28	19.75	20.19	20.84	0.8%
Metallurgical coal	0.56	0.55	0.58	0.58	0.55	0.50	0.47	-0.5%
Other coal	1.01	0.98	1.03	1.04	1.04	1.04	1.05	0.3%
Coal-to-liquids heat and power	0.00	0.00	0.00	0.00	0.00	0.00	0.00	- -
Net coal coke imports	0.01	0.00	0.00	-0.01	-0.03	-0.05	-0.05	- -
Coal subtotal	1.59	1.53	1.61	1.62	1.56	1.50	1.48	-0.1%
Biofuels heat and coproducts	0.46	0.52	0.76	0.79	0.79	0.79	0.79	1.5%
Renewable energy[14]	2.14	2.06	2.33	2.47	2.58	2.70	2.83	1.1%
Liquid hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	- -
Electricity	12.79	12.58	13.60	14.26	14.76	15.20	15.77	0.8%
Delivered energy	**70.42**	**69.07**	**73.63**	**74.50**	**74.91**	**75.56**	**76.88**	**0.4%**
Electricity related losses	26.69	25.95	27.10	27.95	28.35	28.73	29.43	0.5%
Total	**97.11**	**95.02**	**100.73**	**102.45**	**103.27**	**104.28**	**106.31**	**0.4%**
Electric power[15]								
Distillate fuel oil	0.06	0.05	0.09	0.09	0.09	0.09	0.09	1.8%
Residual fuel oil	0.25	0.18	0.09	0.09	0.09	0.10	0.10	-2.1%
Petroleum and other liquids subtotal	0.32	0.23	0.18	0.18	0.18	0.18	0.19	-0.8%
Natural gas	7.72	9.46	9.00	9.69	10.28	10.91	11.48	0.7%
Steam coal	18.03	15.82	16.95	17.41	17.44	17.32	17.27	0.3%
Nuclear / uranium[16]	8.26	8.05	8.15	8.15	8.18	8.23	8.49	0.2%
Renewable energy[17]	4.80	4.59	6.08	6.42	6.68	6.95	7.44	1.7%
Non-biogenic municipal waste	0.23	0.23	0.23	0.23	0.23	0.23	0.23	0.0%
Electricity imports	0.13	0.16	0.11	0.12	0.12	0.10	0.12	-1.1%
Total	**39.49**	**38.53**	**40.70**	**42.21**	**43.12**	**43.92**	**45.20**	**0.6%**

Table A2. Energy consumption by sector and source (continued)
(quadrillion Btu per year, unless otherwise noted)

Sector and source	Reference case							Annual growth 2012-2040 (percent)
	2011	2012	2020	2025	2030	2035	2040	
Total energy consumption								
Liquefied petroleum gases and other[5]	2.95	2.96	3.53	3.67	3.65	3.56	3.49	0.6%
Motor gasoline[2]	16.67	16.64	15.34	14.04	13.04	12.59	12.44	-1.0%
of which: E85[9]	0.00	0.01	0.19	0.38	0.46	0.43	0.33	11.9%
Jet fuel[10]	3.01	3.00	3.08	3.14	3.20	3.24	3.28	0.3%
Kerosene	0.03	0.01	0.01	0.01	0.01	0.01	0.01	0.9%
Distillate fuel oil	8.29	7.98	9.03	9.33	9.50	9.64	9.72	0.7%
Residual fuel oil	1.22	0.90	0.89	0.90	0.91	0.92	0.93	0.1%
Petrochemical feedstocks	0.88	0.75	1.27	1.52	1.62	1.62	1.59	2.7%
Other petroleum[13]	3.52	3.64	3.70	3.68	3.73	3.78	3.89	0.2%
Petroleum and other liquids subtotal	36.56	35.87	36.86	36.28	35.65	35.37	35.35	-0.1%
Natural gas	22.86	24.02	25.14	26.22	27.05	27.97	29.07	0.7%
Natural-gas-to-liquids heat and power	0.00	0.00	0.00	0.00	0.00	0.00	0.00	- -
Lease and plant fuel[7]	1.35	1.45	1.77	1.99	2.16	2.29	2.41	1.8%
Pipeline fuel natural gas	0.70	0.73	0.74	0.76	0.82	0.83	0.85	0.5%
Natural gas subtotal	24.91	26.20	27.65	28.97	30.03	31.10	32.32	0.8%
Metallurgical coal	0.56	0.55	0.58	0.58	0.55	0.50	0.47	-0.5%
Other coal	19.05	16.79	17.98	18.45	18.49	18.36	18.32	0.3%
Coal-to-liquids heat and power	0.00	0.00	0.00	0.00	0.00	0.00	0.00	- -
Net coal coke imports	0.01	0.00	0.00	-0.01	-0.03	-0.05	-0.05	- -
Coal subtotal	19.62	17.34	18.56	19.03	19.01	18.82	18.75	0.3%
Nuclear / uranium[16]	8.26	8.05	8.15	8.15	8.18	8.23	8.49	0.2%
Biofuels heat and coproducts	0.46	0.52	0.76	0.79	0.79	0.79	0.79	1.5%
Renewable energy[18]	6.95	6.65	8.40	8.88	9.26	9.65	10.27	1.6%
Liquid hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	- -
Non-biogenic municipal waste	0.23	0.23	0.23	0.23	0.23	0.23	0.23	0.0%
Electricity imports	0.13	0.16	0.11	0.12	0.12	0.10	0.12	-1.1%
Total	**97.11**	**95.02**	**100.73**	**102.45**	**103.27**	**104.28**	**106.31**	**0.4%**
Energy use and related statistics								
Delivered energy use	70.42	69.07	73.63	74.50	74.91	75.56	76.88	0.4%
Total energy use	97.11	95.02	100.73	102.45	103.27	104.28	106.31	0.4%
Ethanol consumed in motor gasoline and E85	1.09	1.09	1.22	1.25	1.25	1.25	1.29	0.6%
Population (millions)	312.32	314.58	334.47	346.98	359.03	370.19	380.53	0.7%
Gross domestic product (billion 2005 dollars)	13,299	13,593	16,753	18,769	21,139	23,751	26,670	2.4%
Carbon dioxide emissions (million metric tons)	5,498.1	5,289.9	5,475.9	5,526.2	5,526.9	5,545.7	5,599.1	0.2%

[1]Includes wood used for residential heating. See Table A4 and/or Table A17 for estimates of nonmarketed renewable energy consumption for geothermal heat pumps, solar thermal water heating, and electricity generation from wind and solar photovoltaic sources.
[2]Includes ethanol 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 ethane, natural gasoline, and refinery olefins.
[6]Includes petroleum coke, asphalt, road oil, lubricants, still gas, and miscellaneous petroleum products.
[7]Represents natural gas used in well, field, and lease operations, in natural gas processing plant machinery, and for liquefaction in export facilities.
[8]Includes consumption of energy produced from hydroelectric, wood and wood waste, municipal waste, and other biomass sources. Excludes ethanol in motor gasoline.
[9]E85 refers to a blend of 85 percent ethanol (renewable) and 15 percent motor gasoline (nonrenewable). To address cold starting issues, the percentage of ethanol varies seasonally. The annual average ethanol content of 74 percent is used for this forecast.
[10]Includes only kerosene type.
[11]Diesel fuel for on- and off- road use.
[12]Includes aviation gasoline and lubricants.
[13]Includes aviation gasoline, petroleum coke, asphalt, road oil, lubricants, still gas, and miscellaneous petroleum products.
[14]Includes electricity generated for sale to the grid and for own use from renewable sources, and non-electric energy from renewable sources. Excludes ethanol and nonmarketed renewable energy consumption for geothermal heat pumps, buildings photovoltaic systems, and solar thermal water heaters.
[15]Includes consumption of energy by electricity-only and combined heat and power plants that have a regulatory status.
[16]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.
[17]Includes conventional hydroelectric, geothermal, wood and wood waste, biogenic municipal waste, other biomass, wind, photovoltaic, and solar thermal sources. Excludes net electricity imports.
[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: Includes estimated consumption for petroleum and other liquids. Totals may not equal sum of components due to independent rounding. Data for 2011 and 2012 are model results and may differ from official EIA data reports.
Sources: 2011 and 2012 consumption based on: U.S. Energy Information Administration (EIA), *Monthly Energy Review*, DOE/EIA-0035(2013/09) (Washington, DC, September 2013). 2011 and 2012 population and gross domestic product: IHS Global Insight Industry and Employment models, May 2013. 2011 and 2012 carbon dioxide emissions and emission factors: EIA, *Monthly Energy Review*, DOE/EIA-0035(2013/09) (Washington, DC, September 2013).
Projections: EIA, AEO2014 National Energy Modeling System run REF2014.D102413A.

Table A3. Energy prices by sector and source
(2012 dollars per million Btu, unless otherwise noted)

Sector and source	Reference case							Annual growth 2012-2040 (percent)
	2011	2012	2020	2025	2030	2035	2040	
Residential								
Propane	25.28	24.12	23.79	24.86	25.75	26.84	27.64	0.5%
Distillate fuel oil	26.93	27.30	24.67	26.95	28.60	30.57	32.64	0.6%
Natural gas	10.98	10.46	11.59	12.48	13.50	14.61	15.98	1.5%
Electricity	34.95	34.83	36.15	36.14	36.98	37.82	38.83	0.4%
Commercial								
Propane	22.20	20.75	20.33	21.66	22.79	24.14	25.17	0.7%
Distillate fuel oil	26.43	26.81	21.77	24.01	25.66	27.69	29.72	0.4%
Residual fuel oil	19.41	22.84	14.40	16.13	17.92	19.36	20.99	-0.3%
Natural gas	8.96	8.11	9.49	10.29	11.19	11.95	13.08	1.7%
Electricity	30.53	29.55	30.80	30.55	31.26	31.98	33.01	0.4%
Industrial[1]								
Propane	22.63	21.09	20.64	22.06	23.27	24.73	25.84	0.7%
Distillate fuel oil	27.04	27.41	22.22	24.45	26.11	27.97	29.92	0.3%
Residual fuel oil	19.17	20.90	14.88	16.65	18.29	19.79	21.48	0.1%
Natural gas[2]	5.09	3.77	5.79	6.32	6.99	7.76	8.59	3.0%
Metallurgical coal	7.13	7.25	8.43	8.95	9.51	9.93	10.20	1.2%
Other industrial coal	3.31	3.24	3.59	3.73	3.88	4.03	4.19	0.9%
Coal to liquids	- -	- -	- -	- -	- -	- -	- -	- -
Electricity	20.35	19.50	20.77	21.08	21.99	22.91	24.05	0.8%
Transportation								
Propane	26.29	25.14	24.85	25.92	26.81	28.01	28.82	0.5%
E85[3]	44.13	35.06	25.61	27.53	27.91	30.68	35.49	0.0%
Motor gasoline[4]	30.32	30.68	25.59	27.37	28.54	30.40	32.67	0.2%
Jet fuel[5]	23.02	22.99	19.47	21.96	23.71	25.83	28.07	0.7%
Diesel fuel (distillate fuel oil)[6]	28.37	28.80	26.80	29.02	30.68	32.60	34.53	0.7%
Residual fuel oil	18.05	20.07	12.46	14.16	15.50	16.94	18.55	-0.3%
Natural gas[7]	15.90	14.64	15.62	15.57	16.63	18.09	19.67	1.1%
Electricity	34.00	31.43	29.86	30.09	31.68	32.65	34.19	0.3%
Electric power[8]								
Distillate fuel oil	23.79	24.12	20.66	22.94	24.65	26.68	28.81	0.6%
Residual fuel oil	15.94	20.68	13.86	15.59	17.14	18.74	20.42	0.0%
Natural gas	4.88	3.44	5.07	5.76	6.49	7.29	8.16	3.1%
Steam coal	2.42	2.39	2.61	2.77	2.93	3.05	3.19	1.0%
Average price to all users[9]								
Propane	24.39	23.24	22.54	23.68	24.66	25.89	26.79	0.5%
E85[3]	44.13	35.06	25.61	27.53	27.91	30.68	35.49	0.0%
Motor gasoline[4]	30.18	30.44	25.58	27.37	28.53	30.40	32.67	0.3%
Jet fuel[5]	23.02	22.99	19.47	21.96	23.71	25.83	28.07	0.7%
Distillate fuel oil	27.95	28.36	25.70	27.98	29.67	31.58	33.54	0.6%
Residual fuel oil	17.80	20.41	13.15	14.88	16.32	17.79	19.42	-0.2%
Natural gas	6.83	5.38	7.09	7.72	8.49	9.33	10.38	2.4%
Metallurgical coal	7.13	7.25	8.43	8.95	9.51	9.93	10.20	1.2%
Other coal	2.48	2.44	2.67	2.83	2.98	3.11	3.25	1.0%
Coal to liquids	- -	- -	- -	- -	- -	- -	- -	- -
Electricity	29.52	28.85	29.72	29.67	30.56	31.49	32.63	0.4%
Non-renewable energy expenditures by sector (billion 2012 dollars)								
Residential	249.85	234.06	249.25	258.12	272.82	287.79	306.56	1.0%
Commercial	183.94	173.25	189.44	200.39	215.91	232.66	255.39	1.4%
Industrial[1]	232.59	213.75	279.45	315.89	343.02	365.43	390.91	2.2%
Transportation	757.76	755.09	632.05	653.92	667.67	711.27	772.91	0.1%
Total non-renewable expenditures	1,424.14	1,376.15	1,350.18	1,428.32	1,499.43	1,597.14	1,725.77	0.8%
Transportation renewable expenditures	0.12	0.50	4.89	10.53	12.96	13.30	11.80	11.9%
Total expenditures	**1,424.26**	**1,376.66**	**1,355.07**	**1,438.85**	**1,512.39**	**1,610.44**	**1,737.56**	**0.8%**

Table A3. Energy prices by sector and source (continued)
(nominal dollars per million Btu, unless otherwise noted)

Sector and source	Reference case							Annual growth 2012-2040 (percent)
	2011	2012	2020	2025	2030	2035	2040	
Residential								
Propane	24.83	24.12	26.94	30.63	34.67	39.98	45.83	2.3%
Distillate fuel oil	26.46	27.30	27.94	33.19	38.50	45.53	54.12	2.5%
Natural gas	10.79	10.46	13.13	15.37	18.18	21.75	26.49	3.4%
Electricity	34.34	34.83	40.94	44.52	49.78	56.33	64.39	2.2%
Commercial								
Propane	21.81	20.75	23.02	26.69	30.68	35.95	41.74	2.5%
Distillate fuel oil	25.97	26.81	24.66	29.57	34.54	41.24	49.27	2.2%
Residual fuel oil	19.07	22.84	16.31	19.87	24.12	28.84	34.80	1.5%
Natural gas	8.80	8.11	10.75	12.67	15.07	17.80	21.68	3.6%
Electricity	30.00	29.55	34.88	37.63	42.08	47.64	54.73	2.2%
Industrial[1]								
Propane	22.24	21.09	23.38	27.18	31.32	36.84	42.83	2.6%
Distillate fuel oil	26.56	27.41	25.17	30.12	35.15	41.66	49.61	2.1%
Residual fuel oil	18.84	20.90	16.85	20.51	24.62	29.47	35.61	1.9%
Natural gas[2]	5.00	3.77	6.56	7.79	9.41	11.55	14.25	4.9%
Metallurgical coal	7.01	7.25	9.55	11.03	12.81	14.80	16.91	3.1%
Other industrial coal	3.25	3.24	4.07	4.59	5.23	6.00	6.95	2.8%
Coal to liquids	- -	- -	- -	- -	- -	- -	- -	- -
Electricity	19.99	19.50	23.52	25.96	29.60	34.13	39.88	2.6%
Transportation								
Propane	25.83	25.14	28.14	31.93	36.09	41.71	47.79	2.3%
E85[3]	43.36	35.06	29.00	33.92	37.57	45.69	58.85	1.9%
Motor gasoline[4]	29.79	30.68	28.98	33.72	38.42	45.28	54.17	2.1%
Jet fuel[5]	22.61	22.99	22.06	27.05	31.91	38.47	46.53	2.5%
Diesel fuel (distillate fuel oil)[6]	27.87	28.80	30.35	35.75	41.30	48.56	57.25	2.5%
Residual fuel oil	17.73	20.07	14.11	17.44	20.86	25.23	30.76	1.5%
Natural gas[7]	15.62	14.64	17.69	19.18	22.38	26.95	32.61	2.9%
Electricity	33.40	31.43	33.82	37.07	42.65	48.63	56.68	2.1%
Electric power[8]								
Distillate fuel oil	23.37	24.12	23.40	28.26	33.18	39.74	47.77	2.5%
Residual fuel oil	15.67	20.68	15.70	19.21	23.08	27.92	33.86	1.8%
Natural gas	4.80	3.44	5.75	7.09	8.74	10.85	13.53	5.0%
Steam coal	2.38	2.39	2.96	3.42	3.94	4.54	5.29	2.9%

Table A3. Energy prices by sector and source (continued)
(nominal dollars per million Btu, unless otherwise noted)

Sector and source	Reference case							Annual growth 2012-2040 (percent)
	2011	2012	2020	2025	2030	2035	2040	
Average price to all users[9]								
Propane	23.96	23.24	25.53	29.17	33.20	38.55	44.42	2.3%
E85[3]	43.36	35.06	29.00	33.92	37.57	45.69	58.85	1.9%
Motor gasoline[4]	29.66	30.44	28.98	33.71	38.41	45.28	54.17	2.1%
Jet fuel[5]	22.61	22.99	22.06	27.05	31.91	38.47	46.53	2.5%
Distillate fuel oil	27.46	28.36	29.11	34.46	39.94	47.04	55.61	2.4%
Residual fuel oil	17.49	20.41	14.90	18.32	21.97	26.49	32.20	1.6%
Natural gas	6.71	5.38	8.04	9.51	11.43	13.90	17.22	4.2%
Metallurgical coal	7.01	7.25	9.55	11.03	12.81	14.80	16.91	3.1%
Other coal	2.43	2.44	3.03	3.49	4.02	4.63	5.39	2.9%
Coal to liquids	- -	- -	- -	- -	- -	- -	- -	- -
Electricity	29.01	28.85	33.66	36.55	41.13	46.90	54.11	2.3%
Non-renewable energy expenditures by sector (billion nominal dollars)								
Residential	245.47	234.06	282.30	317.94	367.27	428.63	508.27	2.8%
Commercial	180.72	173.25	214.56	246.83	290.65	346.52	423.44	3.2%
Industrial[1]	228.52	213.75	316.50	389.11	461.77	544.27	648.12	4.0%
Transportation	744.51	755.09	715.87	805.47	898.80	1,059.37	1,281.47	1.9%
Total non-renewable expenditures	1,399.23	1,376.15	1,529.23	1,759.34	2,018.49	2,378.79	2,861.30	2.6%
Transportation renewable expenditures	0.12	0.50	5.54	12.97	17.45	19.81	19.56	14.0%
Total expenditures	**1,399.35**	**1,376.66**	**1,534.77**	**1,772.32**	**2,035.94**	**2,398.59**	**2,880.86**	**2.7%**

[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 fuel in motor vehicles, trains, and ships. Price 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 and 2012 are model results and may differ from official EIA data reports.
Sources: 2011 and 2012 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(2013/08) (Washington, DC, August 2013). 2011 residential, commercial, and industrial natural gas delivered prices: EIA, *Natural Gas Annual 2011*, DOE/EIA-0131(2011) (Washington, DC, December 2012). 2012 residential, commercial, and industrial natural gas delivered prices: EIA, *Natural Gas Monthly*, DOE/EIA-0130(2013/06) (Washington, DC, June 2013). 2011 transportation sector natural gas delivered prices are based on: EIA, *Natural Gas Annual 2011*, DOE/EIA-0131(2011) (Washington, DC, December 2012) and estimated State taxes, Federal taxes, and dispensing costs or charges. 2012 transportation sector natural gas delivered prices are model results. 2011 and 2012 electric power sector distillate and residual fuel oil prices: EIA, *Monthly Energy Review*, DOE/EIA-0035(2013/09) (Washington, DC, September 2013). 2011 and 2012 electric power sector natural gas prices: EIA, *Electric Power Monthly*, DOE/EIA-0226, April 2012 and April 2013, Table 4.2, and EIA, *State Energy Data Report 2011*, DOE/EIA-0214(2011) (Washington, DC, June 2013). 2011 and 2012 coal prices based on: EIA, *Quarterly Coal Report, October-December 2012*, DOE/EIA-0121(2012/4Q) (Washington, DC, March 2013) and EIA, AEO2014 National Energy Modeling System run REF2014.D102413A. 2011 and 2012 electricity prices: EIA, *Monthly Energy Review*, DOE/EIA-0035(2013/09) (Washington, DC, September 2013). 2011 and 2012 E85 prices derived from monthly prices in the Clean Cities Alternative Fuel Price Report.
Projections: EIA, AEO2014 National Energy Modeling System run REF2014.D102413A.

Table A4. Residential sector key indicators and consumption
(quadrillion Btu per year, unless otherwise noted)

Key indicators and consumption	Reference case							Annual growth 2012-2040 (percent)
	2011	2012	2020	2025	2030	2035	2040	
Key indicators								
Households (millions)								
Single-family	78.99	79.28	85.71	89.73	93.56	96.99	100.37	0.8%
Multifamily	28.13	28.24	30.55	32.18	33.98	35.82	37.61	1.0%
Mobile homes	6.58	6.41	5.70	5.46	5.29	5.14	5.03	-0.9%
Total	**113.70**	**113.93**	**121.96**	**127.38**	**132.83**	**137.95**	**143.01**	**0.8%**
Average house square footage	**1,662**	**1,670**	**1,736**	**1,771**	**1,802**	**1,831**	**1,858**	**0.4%**
Energy intensity								
(million Btu per household)								
Delivered energy consumption	99.0	91.5	88.1	84.6	81.5	78.7	76.5	-0.6%
Total energy consumption	188.2	176.4	167.1	161.6	156.8	152.8	150.2	-0.6%
(thousand Btu per square foot)								
Delivered energy consumption	59.6	54.8	50.7	47.8	45.2	43.0	41.2	-1.0%
Total energy consumption	113.2	105.6	96.3	91.2	87.0	83.5	80.9	-1.0%
Delivered energy consumption by fuel								
Purchased electricity								
Space heating	0.37	0.29	0.35	0.35	0.34	0.33	0.32	0.4%
Space cooling	0.83	0.85	0.89	0.98	1.07	1.16	1.25	1.4%
Water heating	0.44	0.45	0.47	0.49	0.50	0.50	0.51	0.5%
Refrigeration	0.38	0.38	0.38	0.38	0.38	0.40	0.41	0.3%
Cooking	0.11	0.11	0.12	0.12	0.13	0.14	0.15	1.1%
Clothes dryers	0.20	0.20	0.21	0.22	0.23	0.24	0.25	0.8%
Freezers	0.08	0.08	0.08	0.08	0.08	0.08	0.08	-0.1%
Lighting	0.64	0.64	0.44	0.39	0.35	0.30	0.28	-2.9%
Clothes washers[1]	0.03	0.03	0.03	0.02	0.02	0.02	0.02	-1.2%
Dishwashers[1]	0.10	0.10	0.10	0.10	0.10	0.11	0.12	0.6%
Televisions and related equipment[2]	0.33	0.33	0.33	0.33	0.35	0.37	0.39	0.5%
Computers and related equipment[3]	0.13	0.12	0.10	0.08	0.07	0.06	0.05	-3.0%
Furnace fans and boiler circulation pumps	0.12	0.09	0.12	0.12	0.12	0.12	0.12	0.8%
Other uses[4]	1.11	1.02	1.24	1.34	1.46	1.58	1.70	1.9%
Delivered energy	**4.85**	**4.69**	**4.84**	**5.00**	**5.21**	**5.41**	**5.65**	**0.7%**
Natural gas								
Space heating	3.09	2.51	2.82	2.76	2.69	2.62	2.54	0.0%
Space cooling	0.02	0.02	0.02	0.02	0.02	0.02	0.02	-0.6%
Water heating	1.20	1.22	1.21	1.22	1.22	1.19	1.16	-0.2%
Cooking	0.21	0.21	0.21	0.21	0.21	0.22	0.22	0.2%
Clothes dryers	0.05	0.05	0.05	0.06	0.06	0.06	0.06	0.7%
Other uses[5]	0.25	0.25	0.24	0.23	0.22	0.22	0.21	-0.6%
Delivered energy	**4.82**	**4.26**	**4.56**	**4.50**	**4.43**	**4.32**	**4.21**	**0.0%**
Distillate fuel oil								
Space heating	0.46	0.44	0.42	0.38	0.34	0.31	0.29	-1.5%
Water heating	0.06	0.06	0.03	0.03	0.02	0.02	0.02	-4.4%
Other uses[6]	0.01	0.01	0.01	0.01	0.01	0.01	0.01	-0.6%
Delivered energy	**0.53**	**0.51**	**0.46**	**0.41**	**0.37**	**0.34**	**0.31**	**-1.7%**
Propane								
Space heating	0.37	0.37	0.30	0.28	0.26	0.25	0.24	-1.6%
Water heating	0.07	0.07	0.05	0.04	0.04	0.03	0.03	-3.3%
Cooking	0.03	0.03	0.03	0.03	0.02	0.02	0.02	-0.9%
Other uses[6]	0.04	0.04	0.05	0.05	0.05	0.06	0.06	1.5%
Delivered energy	**0.51**	**0.51**	**0.42**	**0.40**	**0.38**	**0.36**	**0.35**	**-1.3%**
Marketed renewables (wood)[7]	0.54	0.45	0.46	0.45	0.44	0.43	0.42	-0.3%
Kerosene	0.02	0.01	0.00	0.00	0.00	0.00	0.00	-2.5%

Table A4. Residential sector key indicators and consumption (continued)
(quadrillion Btu per year, unless otherwise noted)

Key indicators and consumption	Reference case							Annual growth 2012-2040 (percent)
	2011	2012	2020	2025	2030	2035	2040	
Delivered energy consumption by end use								
Space heating	4.84	4.07	4.36	4.22	4.09	3.95	3.81	-0.2%
Space cooling	0.85	0.88	0.91	1.00	1.09	1.18	1.27	1.3%
Water heating	1.77	1.79	1.77	1.78	1.78	1.74	1.71	-0.2%
Refrigeration	0.38	0.38	0.38	0.38	0.38	0.40	0.41	0.3%
Cooking	0.34	0.34	0.35	0.36	0.37	0.38	0.39	0.4%
Clothes dryers	0.25	0.25	0.27	0.28	0.29	0.30	0.31	0.8%
Freezers	0.08	0.08	0.08	0.08	0.08	0.08	0.08	-0.1%
Lighting	0.64	0.64	0.44	0.39	0.35	0.30	0.28	-2.9%
Clothes washers[1]	0.03	0.03	0.03	0.02	0.02	0.02	0.02	-1.2%
Dishwashers[1]	0.10	0.10	0.10	0.10	0.10	0.11	0.12	0.6%
Televisions and related equipment[2]	0.33	0.33	0.33	0.33	0.35	0.37	0.39	0.5%
Computers and related equipment[3]	0.13	0.12	0.10	0.08	0.07	0.06	0.05	-3.0%
Furnace fans and boiler circulation pumps	0.12	0.09	0.12	0.12	0.12	0.12	0.12	0.8%
Other uses[8]	1.40	1.31	1.53	1.63	1.74	1.86	1.98	1.5%
Delivered energy	**11.26**	**10.42**	**10.74**	**10.77**	**10.83**	**10.86**	**10.94**	**0.2%**
Electricity related losses	**10.13**	**9.68**	**9.64**	**9.81**	**10.00**	**10.22**	**10.55**	**0.3%**
Total energy consumption by end use								
Space heating	5.63	4.66	5.05	4.90	4.74	4.57	4.41	-0.2%
Space cooling	2.58	2.64	2.68	2.91	3.14	3.37	3.61	1.1%
Water heating	2.68	2.71	2.71	2.74	2.74	2.69	2.65	-0.1%
Refrigeration	1.17	1.16	1.12	1.12	1.12	1.15	1.19	0.1%
Cooking	0.56	0.56	0.59	0.60	0.62	0.64	0.66	0.6%
Clothes dryers	0.66	0.66	0.69	0.71	0.73	0.76	0.78	0.6%
Freezers	0.25	0.25	0.24	0.23	0.23	0.22	0.23	-0.3%
Lighting	1.97	1.95	1.31	1.16	1.02	0.86	0.79	-3.2%
Clothes washers[1]	0.10	0.10	0.08	0.07	0.06	0.06	0.06	-1.4%
Dishwashers[1]	0.31	0.31	0.29	0.29	0.30	0.32	0.34	0.4%
Televisions and related equipment[2]	1.03	1.02	0.98	0.99	1.02	1.07	1.11	0.3%
Computers and related equipment[3]	0.39	0.38	0.29	0.25	0.21	0.18	0.15	-3.3%
Furnace fans and boiler circulation pumps	0.36	0.29	0.34	0.34	0.34	0.34	0.34	0.6%
Other uses[8]	3.71	3.42	4.01	4.27	4.55	4.84	5.16	1.5%
Total	**21.39**	**20.10**	**20.38**	**20.58**	**20.83**	**21.09**	**21.48**	**0.2%**
Nonmarketed renewables[9]								
Geothermal heat pumps	0.01	0.01	0.02	0.02	0.02	0.02	0.03	3.2%
Solar hot water heating	0.00	0.01	0.01	0.01	0.01	0.01	0.01	2.4%
Solar photovoltaic	0.02	0.02	0.10	0.12	0.14	0.18	0.22	8.3%
Wind	0.00	0.00	0.01	0.01	0.01	0.01	0.01	9.1%
Total	**0.03**	**0.04**	**0.14**	**0.16**	**0.19**	**0.23**	**0.27**	**6.9%**
Heating degree days[10]	**4,258**	**3,712**	**4,015**	**3,945**	**3,877**	**3,810**	**3,745**	**0.0%**
Cooling degree days[10]	**1,481**	**1,514**	**1,488**	**1,530**	**1,572**	**1,614**	**1,656**	**0.3%**

[1]Does not include water heating portion of load.
[2]Includes televisions, set-top boxes, home theater systems, DVD players, and video game consoles.
[3]Includes desktop and laptop computers, monitors, and networking equipment.
[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, exterior lights, pool heaters, spa heaters, and backup electricity generators.
[6]Includes such appliances as pool heaters, spa heaters, and backup electricity generators.
[7]Includes wood used for primary and secondary heating in wood stoves or fireplaces as reported in the *Residential Energy Consumption Survey 2009*.
[8]Includes small electric devices, heating elements, outdoor grills, exterior lights, pool heaters, spa heaters, backup electricity generators, and motors not listed above. Electric vehicles are included in the transportation sector.
[9]Consumption determined by using the fossil fuel equivalent of 9,716 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 2011 and 2012 are model results and may differ from official EIA data reports.
Sources: 2011 and 2012 consumption based on: U.S. Energy Information Administration (EIA), *Monthly Energy Review*, DOE/EIA-0035(2013/09) (Washington, DC, September 2013). 2011 and 2012 degree days based on state-level data from the National Oceanic and Atmospheric Administration's Climatic Data Center and Climate Prediction Center. **Projections:** EIA, AEO2014 National Energy Modeling System run REF2014.D102413A.

Table A5. Commercial sector key indicators and consumption
(quadrillion Btu per year, unless otherwise noted)

Key indicators and consumption	Reference case							Annual growth 2012-2040 (percent)
	2011	2012	2020	2025	2030	2035	2040	
Key indicators								
Total floorspace (billion square feet)								
Surviving	80.2	80.8	87.1	91.9	96.2	100.8	106.5	1.0%
New additions	1.5	1.6	2.1	2.0	2.0	2.3	2.4	1.6%
Total	**81.7**	**82.4**	**89.1**	**93.9**	**98.2**	**103.1**	**108.9**	**1.0%**
Energy consumption intensity (thousand Btu per square foot)								
Delivered energy consumption	105.2	100.7	98.5	96.7	95.6	94.6	93.9	-0.3%
Electricity related losses	115.7	113.2	104.8	103.1	101.3	99.4	98.0	-0.5%
Total energy consumption	220.9	213.8	203.3	199.9	196.9	194.0	191.8	-0.4%
Delivered energy consumption by fuel								
Purchased electricity								
Space heating[1]	0.17	0.15	0.16	0.16	0.15	0.15	0.14	-0.1%
Space cooling[1]	0.55	0.55	0.51	0.53	0.53	0.55	0.57	0.1%
Water heating[1]	0.09	0.09	0.09	0.09	0.09	0.08	0.08	-0.4%
Ventilation	0.51	0.52	0.55	0.57	0.59	0.60	0.62	0.6%
Cooking	0.02	0.02	0.02	0.02	0.02	0.02	0.02	-0.3%
Lighting	0.96	0.94	0.88	0.88	0.87	0.85	0.84	-0.4%
Refrigeration	0.39	0.38	0.37	0.37	0.38	0.39	0.41	0.2%
Office equipment (PC)	0.13	0.12	0.07	0.05	0.04	0.03	0.02	-5.6%
Office equipment (non-PC)	0.22	0.22	0.24	0.27	0.31	0.35	0.38	2.0%
Other uses[2]	1.50	1.53	1.80	2.00	2.20	2.41	2.63	2.0%
Delivered energy	**4.53**	**4.52**	**4.69**	**4.94**	**5.18**	**5.42**	**5.72**	**0.8%**
Natural gas								
Space heating[1]	1.72	1.54	1.71	1.68	1.64	1.59	1.54	0.0%
Space cooling[1]	0.04	0.04	0.04	0.04	0.04	0.04	0.04	-0.7%
Water heating[1]	0.47	0.48	0.50	0.51	0.52	0.52	0.53	0.3%
Cooking	0.19	0.20	0.21	0.22	0.23	0.23	0.24	0.7%
Other uses[3]	0.81	0.70	0.78	0.84	0.94	1.09	1.30	2.2%
Delivered energy	**3.22**	**2.96**	**3.23**	**3.29**	**3.35**	**3.48**	**3.65**	**0.7%**
Distillate fuel oil								
Space heating[1]	0.15	0.13	0.14	0.13	0.12	0.11	0.11	-0.8%
Water heating[1]	0.03	0.03	0.04	0.05	0.05	0.06	0.06	2.5%
Other uses[4]	0.23	0.24	0.21	0.21	0.21	0.20	0.20	-0.7%
Delivered energy	**0.42**	**0.40**	**0.40**	**0.39**	**0.38**	**0.37**	**0.37**	**-0.3%**
Marketed renewables (biomass)	0.11	0.13	0.13	0.13	0.13	0.13	0.13	0.0%
Other fuels[5]	0.31	0.28	0.33	0.33	0.34	0.35	0.36	0.9%
Delivered energy consumption by end use								
Space heating[1]	2.04	1.82	2.01	1.97	1.91	1.85	1.79	-0.1%
Space cooling[1]	0.59	0.60	0.55	0.56	0.57	0.58	0.60	0.0%
Water heating[1]	0.59	0.60	0.63	0.65	0.66	0.66	0.67	0.4%
Ventilation	0.51	0.52	0.55	0.57	0.59	0.60	0.62	0.6%
Cooking	0.21	0.22	0.23	0.24	0.25	0.26	0.26	0.6%
Lighting	0.96	0.94	0.88	0.88	0.87	0.85	0.84	-0.4%
Refrigeration	0.39	0.38	0.37	0.37	0.38	0.39	0.41	0.2%
Office equipment (PC)	0.13	0.12	0.07	0.05	0.04	0.03	0.02	-5.6%
Office equipment (non-PC)	0.22	0.22	0.24	0.27	0.31	0.35	0.38	2.0%
Other uses[6]	2.96	2.88	3.26	3.52	3.81	4.18	4.62	1.7%
Delivered energy	**8.60**	**8.29**	**8.78**	**9.08**	**9.38**	**9.75**	**10.22**	**0.7%**

Table A5. Commercial sector key indicators and consumption (continued)
(quadrillion Btu per year, unless otherwise noted)

Key indicators and consumption	Reference case							Annual growth 2012-2040 (percent)
	2011	2012	2020	2025	2030	2035	2040	
Electricity related losses	**9.46**	**9.32**	**9.34**	**9.69**	**9.94**	**10.24**	**10.66**	**0.5%**
Total energy consumption by end use								
Space heating[1]	2.40	2.13	2.33	2.28	2.20	2.13	2.06	-0.1%
Space cooling[1]	1.73	1.74	1.57	1.59	1.60	1.62	1.66	-0.2%
Water heating[1]	0.78	0.80	0.81	0.82	0.83	0.82	0.82	0.1%
Ventilation	1.58	1.58	1.64	1.69	1.71	1.73	1.77	0.4%
Cooking	0.26	0.27	0.28	0.28	0.29	0.30	0.30	0.4%
Lighting	2.95	2.87	2.63	2.60	2.54	2.45	2.41	-0.6%
Refrigeration	1.20	1.17	1.10	1.10	1.11	1.13	1.16	0.0%
Office equipment (PC)	0.39	0.35	0.20	0.15	0.11	0.08	0.07	-5.8%
Office equipment (non-PC)	0.69	0.67	0.72	0.80	0.90	1.00	1.10	1.8%
Other uses[6]	6.08	6.04	6.85	7.45	8.04	8.73	9.54	1.6%
Total	**18.05**	**17.61**	**18.12**	**18.77**	**19.32**	**19.99**	**20.88**	**0.6%**
Nonmarketed renewable fuels[7]								
Solar thermal	0.08	0.08	0.09	0.09	0.09	0.10	0.11	1.0%
Solar photovoltaic	0.03	0.05	0.10	0.12	0.15	0.19	0.24	5.9%
Wind	0.00	0.00	0.00	0.00	0.00	0.01	0.01	8.3%
Total	**0.11**	**0.13**	**0.18**	**0.21**	**0.24**	**0.29**	**0.35**	**3.7%**
Heating degree days								
New England	6,082	5,541	6,045	5,975	5,905	5,835	5,763	0.1%
Middle Atlantic	5,405	4,886	5,307	5,229	5,152	5,076	5,000	0.1%
East North Central	6,163	5,350	5,933	5,867	5,801	5,735	5,669	0.2%
West North Central	6,635	5,537	6,226	6,170	6,112	6,053	5,992	0.3%
South Atlantic	2,568	2,297	2,588	2,551	2,516	2,481	2,448	0.2%
East South Central	3,358	2,896	3,258	3,218	3,177	3,135	3,093	0.2%
West South Central	2,145	1,683	1,924	1,870	1,815	1,761	1,707	0.1%
Mountain	5,223	4,445	4,660	4,586	4,508	4,428	4,347	-0.1%
Pacific	3,532	3,150	3,244	3,267	3,290	3,314	3,339	0.2%
United States	**4,258**	**3,712**	**4,015**	**3,945**	**3,877**	**3,810**	**3,745**	**0.0%**
Cooling degree days								
New England	568	592	565	583	601	620	638	0.3%
Middle Atlantic	885	863	848	875	903	929	956	0.4%
East North Central	855	982	825	835	846	856	867	-0.4%
West North Central	1,064	1,231	1,024	1,032	1,041	1,051	1,061	-0.5%
South Atlantic	2,267	2,184	2,208	2,244	2,280	2,316	2,350	0.3%
East South Central	1,740	1,780	1,795	1,829	1,863	1,897	1,931	0.3%
West South Central	3,067	2,903	2,880	2,948	3,017	3,086	3,155	0.3%
Mountain	1,506	1,664	1,661	1,719	1,779	1,841	1,905	0.5%
Pacific	767	917	860	861	861	861	861	-0.2%
United States	**1,481**	**1,514**	**1,488**	**1,530**	**1,572**	**1,614**	**1,656**	**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, propane, 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, propane, coal, motor gasoline, kerosene, and marketed renewable fuels (biomass).
[7]Consumption determined by using the fossil fuel equivalent of 9,716 Btu per kilowatthour.
Btu = British thermal unit.
PC = Personal computer.
Note: Totals may not equal sum of components due to independent rounding. Data for 2011 and 2012 are model results and may differ from official EIA data reports.
Sources: 2011 and 2012 consumption based on: U.S. Energy Information Administration (EIA), *Monthly Energy Review*, DOE/EIA-0035(2013/09) (Washington, DC, September 2013). 2011 and 2012 degree days based on state-level data from the National Oceanic and Atmospheric Administration's Climatic Data Center and Climate Prediction Center. **Projections:** EIA, AEO2014 National Energy Modeling System run REF2014.D102413A.

Table A6. Industrial sector key indicators and consumption

Shipments, prices, and consumption	Reference case							Annual growth 2012-2040 (percent)
	2011	2012	2020	2025	2030	2035	2040	
Key indicators								
Value of shipments (billion 2005 dollars)								
Manufacturing	4,370	4,525	5,735	6,467	7,148	7,784	8,443	2.3%
Agriculture, mining, and construction	1,556	1,623	2,226	2,311	2,389	2,457	2,551	1.6%
Total	**5,926**	**6,147**	**7,960**	**8,778**	**9,537**	**10,241**	**10,994**	**2.1%**
Energy prices								
(2012 dollars per million Btu)								
Propane	22.63	21.09	20.64	22.06	23.27	24.73	25.84	0.7%
Motor gasoline	23.19	17.52	25.56	27.34	28.51	30.36	32.62	2.2%
Distillate fuel oil	27.04	27.41	22.22	24.45	26.11	27.97	29.92	0.3%
Residual fuel oil	19.17	20.90	14.88	16.65	18.29	19.79	21.48	0.1%
Asphalt and road oil	10.13	10.11	10.85	12.26	13.38	14.60	15.80	1.6%
Natural gas heat and power	4.80	3.43	5.59	6.11	6.79	7.58	8.43	3.3%
Natural gas feedstocks	5.41	4.16	6.01	6.55	7.21	7.96	8.78	2.7%
Metallurgical coal	7.13	7.25	8.43	8.95	9.51	9.93	10.20	1.2%
Other industrial coal	3.31	3.24	3.59	3.73	3.88	4.03	4.19	0.9%
Coal to liquids	- -	- -	- -	- -	- -	- -	- -	- -
Electricity	20.35	19.50	20.77	21.08	21.99	22.91	24.05	0.8%
(nominal dollars per million Btu)								
Propane	22.24	21.09	23.38	27.18	31.32	36.84	42.83	2.6%
Motor gasoline	22.79	17.52	28.95	33.68	38.37	45.22	54.08	4.1%
Distillate fuel oil	26.56	27.41	25.17	30.12	35.15	41.66	49.61	2.1%
Residual fuel oil	18.84	20.90	16.85	20.51	24.62	29.47	35.61	1.9%
Asphalt and road oil	9.95	10.11	12.29	15.10	18.02	21.75	26.20	3.5%
Natural gas heat and power	4.72	3.43	6.33	7.53	9.14	11.29	13.98	5.1%
Natural gas feedstocks	5.32	4.16	6.81	8.07	9.70	11.86	14.56	4.6%
Metallurgical coal	7.01	7.25	9.55	11.03	12.81	14.80	16.91	3.1%
Other industrial coal	3.25	3.24	4.07	4.59	5.23	6.00	6.95	2.8%
Coal to liquids	- -	- -	- -	- -	- -	- -	- -	- -
Electricity	19.99	19.50	23.52	25.96	29.60	34.13	39.88	2.6%
Energy consumption (quadrillion Btu)[1]								
Industrial consumption excluding refining								
Propane heat and power	0.13	0.08	0.15	0.16	0.16	0.15	0.15	2.2%
Liquefied petroleum gas and other feedstocks[2]	2.12	2.16	2.75	2.89	2.89	2.81	2.75	0.9%
Motor gasoline	0.26	0.26	0.30	0.30	0.30	0.29	0.29	0.4%
Distillate fuel oil	1.24	1.19	1.40	1.41	1.41	1.41	1.42	0.6%
Residual fuel oil	0.13	0.10	0.14	0.14	0.15	0.15	0.15	1.5%
Petrochemical feedstocks	0.88	0.75	1.27	1.52	1.62	1.62	1.59	2.7%
Petroleum coke	0.12	0.15	0.16	0.16	0.16	0.15	0.16	0.1%
Asphalt and road oil	0.86	0.83	1.13	1.16	1.21	1.26	1.32	1.7%
Miscellaneous petroleum[3]	0.45	0.56	0.47	0.51	0.54	0.55	0.57	0.0%
Petroleum and other liquids subtotal	6.18	6.09	7.76	8.25	8.43	8.41	8.41	1.2%
Natural gas heat and power	5.14	5.22	5.79	6.05	6.18	6.26	6.35	0.7%
Natural gas feedstocks	0.53	0.58	0.68	0.71	0.70	0.69	0.68	0.5%
Lease and plant fuel[4]	1.35	1.45	1.77	1.99	2.16	2.29	2.41	1.8%
Natural gas subtotal	7.03	7.25	8.25	8.74	9.04	9.24	9.43	0.9%
Metallurgical coal and coke[5]	0.58	0.55	0.58	0.57	0.52	0.46	0.42	-0.9%
Other industrial coal	0.95	0.93	0.99	1.00	1.00	1.00	1.01	0.3%
Coal subtotal	1.52	1.48	1.57	1.57	1.52	1.45	1.44	-0.1%
Renewables[6]	1.49	1.48	1.74	1.88	2.01	2.13	2.28	1.6%
Purchased electricity	3.18	3.15	3.87	4.11	4.17	4.16	4.18	1.0%
Delivered energy	**19.40**	**19.45**	**23.18**	**24.56**	**25.17**	**25.39**	**25.73**	**1.0%**
Electricity related losses	6.64	6.50	7.71	8.06	8.02	7.86	7.80	0.7%
Total	**26.04**	**25.95**	**30.90**	**32.61**	**33.19**	**33.25**	**33.53**	**0.9%**

Table A6. Industrial sector key indicators and consumption (continued)

Shipments, prices, and consumption	Reference case							Annual growth 2012-2040 (percent)
	2011	2012	2020	2025	2030	2035	2040	
Refining consumption								
Liquefied petroleum gas heat and power[2]	0.00	0.01	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	0.00	0.00	0.00	0.00	0.00	0.00	0.00	- -
Petroleum coke	0.53	0.54	0.45	0.41	0.40	0.39	0.40	-1.1%
Still gas	1.40	1.41	1.35	1.29	1.28	1.28	1.30	-0.3%
Miscellaneous petroleum[3]	0.01	0.01	0.00	0.00	0.00	0.00	0.00	- -
Petroleum and other liquids subtotal	1.95	1.97	1.80	1.70	1.67	1.67	1.69	-0.5%
Natural gas heat and power	1.09	1.19	1.43	1.48	1.47	1.47	1.48	0.8%
Natural gas feedstocks	0.29	0.30	0.36	0.36	0.36	0.36	0.36	0.6%
Natural-gas-to-liquids heat and power	0.00	0.00	0.00	0.00	0.00	0.00	0.00	- -
Natural gas subtotal	1.38	1.50	1.79	1.84	1.83	1.83	1.85	0.8%
Other industrial coal	0.00	0.00	0.00	0.00	0.00	0.00	0.00	- -
Coal-to-liquids heat and power	0.00	0.00	0.00	0.00	0.00	0.00	0.00	- -
Coal subtotal	0.00	0.00	0.00	0.00	0.00	0.00	0.00	- -
Biofuels heat and coproducts	0.46	0.52	0.76	0.79	0.79	0.79	0.79	1.5%
Purchased electricity	0.20	0.20	0.17	0.17	0.16	0.16	0.16	-0.7%
Delivered energy	**4.00**	**4.18**	**4.52**	**4.49**	**4.45**	**4.45**	**4.49**	**0.3%**
Electricity related losses	0.42	0.40	0.34	0.32	0.31	0.30	0.30	-1.0%
Total	**4.42**	**4.59**	**4.86**	**4.82**	**4.76**	**4.76**	**4.79**	**0.2%**
Total industrial sector consumption								
Liquefied petroleum gas heat and power[2]	0.13	0.09	0.15	0.16	0.16	0.15	0.15	1.9%
Liquefied petroleum gas and other feedstocks[2]	2.12	2.16	2.75	2.89	2.89	2.81	2.75	0.9%
Motor gasoline	0.26	0.26	0.30	0.30	0.30	0.29	0.29	0.4%
Distillate fuel oil	1.24	1.20	1.40	1.41	1.41	1.41	1.42	0.6%
Residual fuel oil	0.13	0.10	0.14	0.14	0.15	0.15	0.15	1.4%
Petrochemical feedstocks	0.88	0.75	1.27	1.52	1.62	1.62	1.59	2.7%
Petroleum coke	0.65	0.69	0.61	0.57	0.56	0.55	0.56	-0.8%
Asphalt and road oil	0.86	0.83	1.13	1.16	1.21	1.26	1.32	1.7%
Still gas	1.40	1.41	1.35	1.29	1.28	1.28	1.30	-0.3%
Miscellaneous petroleum[3]	0.46	0.57	0.47	0.51	0.54	0.55	0.57	0.0%
Petroleum and other liquids subtotal	8.13	8.06	9.56	9.95	10.10	10.08	10.10	0.8%
Natural gas heat and power	6.24	6.41	7.23	7.52	7.65	7.74	7.83	0.7%
Natural gas feedstocks	0.82	0.88	1.04	1.07	1.06	1.05	1.04	0.6%
Natural-gas-to-liquids heat and power	0.00	0.00	0.00	0.00	0.00	0.00	0.00	- -
Lease and plant fuel[4]	1.35	1.45	1.77	1.99	2.16	2.29	2.41	1.8%
Natural gas subtotal	8.41	8.75	10.04	10.58	10.87	11.07	11.28	0.9%
Metallurgical coal and coke[5]	0.58	0.55	0.58	0.57	0.52	0.46	0.42	-0.9%
Other industrial coal	0.95	0.93	0.99	1.00	1.00	1.00	1.01	0.3%
Coal-to-liquids heat and power	0.00	0.00	0.00	0.00	0.00	0.00	0.00	- -
Coal subtotal	1.53	1.48	1.57	1.57	1.52	1.45	1.44	-0.1%
Biofuels heat and coproducts	0.46	0.52	0.76	0.79	0.79	0.79	0.79	1.5%
Renewables[6]	1.49	1.48	1.74	1.88	2.01	2.13	2.28	1.6%
Purchased electricity	3.38	3.35	4.04	4.27	4.33	4.32	4.34	0.9%
Delivered energy	**23.40**	**23.63**	**27.71**	**29.05**	**29.62**	**29.84**	**30.22**	**0.9%**
Electricity related losses	7.06	6.91	8.05	8.38	8.33	8.16	8.10	0.6%
Total	**30.46**	**30.54**	**35.76**	**37.43**	**37.94**	**38.00**	**38.33**	**0.8%**

Table A6. Industrial sector key indicators and consumption (continued)

Key indicators and consumption	Reference case							Annual growth 2012-2040 (percent)
	2011	2012	2020	2025	2030	2035	2040	
Energy consumption per dollar of shipments (thousand Btu per 2005 dollar)								
Petroleum and other liquids	1.37	1.31	1.20	1.13	1.06	0.98	0.92	-1.3%
Natural gas	1.42	1.42	1.26	1.21	1.14	1.08	1.03	-1.2%
Coal	0.26	0.24	0.20	0.18	0.16	0.14	0.13	-2.2%
Renewable fuels[5]	0.33	0.33	0.31	0.30	0.29	0.29	0.28	-0.5%
Purchased electricity	0.57	0.54	0.51	0.49	0.45	0.42	0.40	-1.1%
Delivered energy	**3.95**	**3.84**	**3.48**	**3.31**	**3.11**	**2.91**	**2.75**	**-1.2%**
Industrial combined heat and power[1]								
Capacity (gigawatts)	25.51	26.95	31.11	34.21	38.48	43.27	46.16	1.9%
Generation (billion kilowatthours)	140.20	143.79	169.54	185.50	207.81	233.21	249.22	2.0%

[1]Includes combined heat and power plants that have a regulatory status, and small on-site generating systems.
[2]Includes ethane, natural gasoline, and refinery olefins.
[3]Includes lubricants and miscellaneous petroleum products.
[4]Represents natural gas used in well, field, and lease operations, in natural gas processing plant machinery, and for liquefaction in export facilities.
[5]Includes net coal coke imports.
[6]Includes consumption of energy produced from hydroelectric, wood and wood waste, municipal waste, and other biomass sources.
Btu = British thermal unit.
- - = Not applicable.
Note: Includes estimated consumption for petroleum and other liquids. Totals may not equal sum of components due to independent rounding. Data for 2011 and 2012 are model results and may differ from official EIA data reports.
Sources: 2011 and 2012 prices for motor gasoline and distillate fuel oil are based on: U.S. Energy Information Administration (EIA), *Petroleum Marketing Monthly*, DOE/EIA-0380(2013/08) (Washington, DC, August 2013). 2011 and 2012 petrochemical feedstock and asphalt and road oil prices are based on: EIA, *State Energy Data Report 2011*, DOE/EIA-0214(2011) (Washington, DC, June 2013). 2011 and 2012 coal prices are based on: EIA, *Quarterly Coal Report, October-December 2012*, DOE/EIA-0121(2012/4Q) (Washington, DC, March 2013) and EIA, AEO2014 National Energy Modeling System run REF2014.D102413A. 2011 and 2012 electricity prices: EIA, *Monthly Energy Review*, DOE/EIA-0035(2013/09) (Washington, DC, September 2013). 2011 natural gas prices: EIA, *Natural Gas Annual 2011*, DOE/EIA-0131(2011) (Washington, DC, December 2012) and EIA, Office of Energy Analysis. 2012 natural gas prices: *Natural Gas Monthly*, DOE/EIA-0130(2013/06) (Washington, DC, June 2013) and EIA, Office of Energy Analysis. 2011 refining consumption values are based on: *Petroleum Supply Annual 2011*, DOE/EIA-0340(2011)/1 (Washington, DC, August 2012). 2012 refining consumption based on: *Petroleum Supply Annual 2012*, DOE/EIA-0340(2012)/1 (Washington, DC, September 2013). Other 2011 and 2012 consumption values are based on: EIA, *Monthly Energy Review*, DOE/EIA-0035(2013/09) (Washington, DC, September 2013). 2011 and 2012 shipments: IHS Global Insight, Global Insight Industry model, May 2013. **Projections:** EIA, AEO2014 National Energy Modeling System run REF2014.D102413A.

Table A7. Transportation sector key indicators and delivered energy consumption

Key indicators and consumption	Reference case							Annual growth 2012-2040 (percent)
	2011	2012	2020	2025	2030	2035	2040	
Key indicators								
Travel indicators								
(billion vehicle miles traveled)								
Light-duty vehicles less than 8,501 pounds	2,623	2,662	2,851	2,977	3,138	3,303	3,434	0.9%
Commercial light trucks[1]	62	63	76	83	90	96	103	1.8%
Freight trucks greater than 10,000 pounds	252	245	310	339	362	385	411	1.9%
(billion seat miles available)								
Air	982	990	1,064	1,101	1,135	1,165	1,199	0.7%
(billion ton miles traveled)								
Rail	1,746	1,729	1,624	1,721	1,738	1,737	1,736	0.0%
Domestic shipping	447	378	390	378	369	367	371	-0.1%
Energy efficiency indicators								
(miles per gallon)								
New light-duty vehicle CAFE standard[2]	27.6	29.4	36.6	46.4	46.6	46.7	46.8	1.7%
New car[2]	30.7	33.4	43.7	54.3	54.3	54.3	54.3	1.8%
New light truck[2]	24.6	25.7	30.9	39.5	39.5	39.5	39.5	1.5%
Compliance new light-duty vehicle[3]	32.4	32.7	38.6	47.2	47.8	48.1	48.2	1.4%
New car[3]	36.7	37.1	44.2	54.9	55.4	55.6	55.6	1.5%
New light truck[3]	28.5	28.7	33.7	40.3	40.8	40.9	40.9	1.3%
Tested new light-duty vehicle[4]	31.2	31.7	38.6	47.2	47.8	48.0	48.2	1.5%
New car[4]	35.7	36.3	44.2	54.9	55.4	55.5	55.6	1.5%
New light truck[4]	27.3	27.5	33.7	40.3	40.7	40.9	40.8	1.4%
On-road new light-duty vehicle[5]	25.2	25.6	31.2	38.1	38.6	38.8	38.9	1.5%
New car[5]	29.2	29.7	36.1	44.8	45.2	45.4	45.4	1.5%
New light truck[5]	21.8	22.0	27.0	32.2	32.6	32.7	32.7	1.4%
Light-duty stock[6]	21.2	21.5	25.1	28.7	32.6	35.4	37.2	2.0%
New commercial light truck[1]	18.1	18.1	20.9	24.2	24.5	24.6	24.6	1.1%
Stock commercial light truck[1]	14.9	15.2	18.0	20.4	22.5	23.9	24.5	1.7%
Freight truck	6.7	6.7	7.3	7.5	7.7	7.8	7.8	0.5%
(seat miles per gallon)								
Aircraft	62.3	62.4	63.9	65.2	67.0	69.2	71.5	0.5%
(ton miles per thousand Btu)								
Rail	3.4	3.4	3.6	3.8	3.9	4.1	4.2	0.7%
Domestic shipping	4.6	4.7	5.0	5.2	5.4	5.6	5.8	0.8%
Energy use by mode								
(quadrillion Btu)								
Light-duty vehicles	15.52	15.49	14.24	13.01	12.09	11.70	11.58	-1.0%
Commercial light trucks[1]	0.52	0.52	0.53	0.51	0.50	0.50	0.53	0.0%
Bus transportation	0.24	0.24	0.25	0.26	0.27	0.28	0.29	0.7%
Freight trucks	5.19	5.02	5.87	6.19	6.47	6.80	7.23	1.3%
Rail, passenger	0.05	0.05	0.05	0.05	0.05	0.06	0.06	0.9%
Rail, freight	0.51	0.48	0.45	0.46	0.45	0.43	0.42	-0.5%
Shipping, domestic	0.11	0.10	0.09	0.09	0.08	0.08	0.08	-0.8%
Shipping, international	0.77	0.58	0.59	0.59	0.60	0.61	0.61	0.2%
Recreational boats	0.24	0.24	0.25	0.26	0.27	0.28	0.28	0.6%
Air	2.46	2.47	2.60	2.65	2.69	2.69	2.70	0.3%
Military use	0.74	0.70	0.64	0.65	0.68	0.72	0.77	0.3%
Lubricants	0.13	0.12	0.12	0.12	0.12	0.12	0.12	0.1%
Pipeline fuel	0.70	0.73	0.74	0.76	0.82	0.83	0.85	0.5%
Total	**27.17**	**26.74**	**26.41**	**25.61**	**25.09**	**25.11**	**25.51**	**-0.2%**

Table A7. Transportation sector key indicators and delivered energy consumption (continued)

Key indicators and consumption	Reference case							Annual growth 2012-2040 (percent)
	2011	2012	2020	2025	2030	2035	2040	
Energy use by mode								
(million barrels per day oil equivalent)								
Light-duty vehicles	8.42	8.41	7.76	7.13	6.65	6.44	6.38	-1.0%
Commercial light trucks[1]	0.27	0.27	0.27	0.26	0.26	0.26	0.27	0.0%
Bus transportation	0.12	0.11	0.12	0.13	0.13	0.13	0.14	0.7%
Freight trucks	2.50	2.42	2.83	2.98	3.12	3.28	3.48	1.3%
Rail, passenger	0.02	0.02	0.02	0.02	0.03	0.03	0.03	0.9%
Rail, freight	0.24	0.23	0.21	0.22	0.21	0.21	0.20	-0.5%
Shipping, domestic	0.05	0.05	0.04	0.04	0.04	0.04	0.04	-0.8%
Shipping, international	0.34	0.25	0.26	0.26	0.26	0.27	0.27	0.2%
Recreational boats	0.13	0.13	0.14	0.14	0.15	0.15	0.15	0.6%
Air	1.19	1.20	1.26	1.28	1.30	1.30	1.31	0.3%
Military use	0.35	0.34	0.31	0.31	0.33	0.35	0.37	0.3%
Lubricants	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.1%
Pipeline fuel	0.33	0.35	0.35	0.36	0.39	0.39	0.40	0.5%
Total	**14.03**	**13.84**	**13.63**	**13.20**	**12.92**	**12.90**	**13.09**	**-0.2%**

[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 2011 and 2012 are model results and may differ from official EIA data reports.
Sources: 2011 and 2012: U.S. Energy Information Administration (EIA), *Monthly Energy Review*, DOE/EIA-0035(2013/09) (Washington, DC, September 2013); EIA, Alternatives to Traditional Transportation Fuels 2009 (Part II - User and Fuel Data), April 2011; Federal Highway Administration, *Highway Statistics 2010* (Washington, DC, February 2012); Oak Ridge National Laboratory, *Transportation Energy Data Book: Edition 32* (Oak Ridge, TN, July 2013); National Highway Traffic and Safety Administration, *Summary of Fuel Economy Performance* (Washington, DC, October 2012); U.S. Department of Commerce, Bureau of the Census, "Vehicle Inventory and Use Survey," EC02TV (Washington, DC, December 2004); EIA, 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, AEO2014 National Energy Modeling System run REF2014.D102413A.

Table A8. Electricity supply, disposition, prices, and emissions
(billion kilowatthours, unless otherwise noted)

Supply, disposition, prices, and emissions	Reference case							Annual growth 2012-2040 (percent)
	2011	2012	2020	2025	2030	2035	2040	
Generation by fuel type								
Electric power sector[1]								
Power only[2]								
Coal	1,692	1,478	1,606	1,650	1,652	1,640	1,635	0.4%
Petroleum	26	18	15	16	15	15	16	-0.5%
Natural gas[3]	804	1,000	1,020	1,135	1,256	1,374	1,471	1.4%
Nuclear power	790	769	779	779	782	786	811	0.2%
Pumped storage/other[4]	1	3	3	3	3	3	3	0.2%
Renewable sources[5]	476	459	600	634	660	686	735	1.7%
Distributed generation (natural gas)	0	0	1	2	2	3	4	- -
Total	**3,790**	**3,727**	**4,025**	**4,217**	**4,370**	**4,508**	**4,675**	**0.8%**
Combined heat and power[6]								
Coal	26	20	26	26	26	26	26	0.9%
Petroleum	2	2	1	1	1	1	1	-3.6%
Natural gas	121	133	134	135	135	134	134	0.0%
Renewable sources	5	5	8	8	8	8	8	1.9%
Total	**157**	**163**	**168**	**169**	**170**	**169**	**169**	**0.1%**
Total electric power sector generation	**3,946**	**3,890**	**4,193**	**4,386**	**4,540**	**4,677**	**4,844**	**0.8%**
Less direct use	12	13	14	14	14	14	14	0.3%
Net available to the grid	**3,935**	**3,877**	**4,179**	**4,373**	**4,526**	**4,663**	**4,830**	**0.8%**
End-use sector[7]								
Coal	15	13	13	13	13	13	13	0.0%
Petroleum	2	3	3	3	3	3	3	-0.4%
Natural gas	88	95	112	130	159	197	231	3.2%
Other gaseous fuels[8]	11	11	18	18	18	18	18	1.8%
Renewable sources[9]	36	39	60	69	80	93	108	3.7%
Other[10]	4	3	3	3	3	3	3	0.0%
Total end-use sector generation	**156**	**165**	**209**	**236**	**276**	**327**	**375**	**3.0%**
Less direct use	115	127	169	193	228	274	317	3.3%
Total sales to the grid	**41**	**38**	**41**	**43**	**47**	**53**	**58**	**1.5%**
Total electricity generation by fuel								
Coal	1,733	1,512	1,646	1,689	1,692	1,679	1,675	0.4%
Petroleum	30	23	18	19	19	19	19	-0.7%
Natural gas	1,014	1,228	1,268	1,401	1,552	1,708	1,839	1.5%
Nuclear power	790	769	779	779	782	786	811	0.2%
Renewable sources[5,9]	517	502	667	711	748	787	851	1.9%
Other[11]	19	19	24	24	24	24	24	0.7%
Total electricity generation	**4,103**	**4,054**	**4,402**	**4,622**	**4,815**	**5,004**	**5,219**	**0.9%**
Net generation to the grid	**3,976**	**3,915**	**4,220**	**4,416**	**4,573**	**4,716**	**4,888**	**0.8%**
Net imports	**37**	**47**	**33**	**35**	**35**	**31**	**35**	**-1.1%**
Electricity sales by sector								
Residential	1,423	1,375	1,418	1,467	1,526	1,585	1,657	0.7%
Commercial	1,328	1,324	1,374	1,448	1,517	1,588	1,675	0.8%
Industrial	991	981	1,184	1,253	1,270	1,265	1,273	0.9%
Transportation	7	7	9	10	13	15	18	3.6%
Total	**3,749**	**3,686**	**3,986**	**4,178**	**4,327**	**4,454**	**4,623**	**0.8%**
Direct use	127	139	182	206	242	288	331	3.1%
Total electricity use	**3,875**	**3,826**	**4,168**	**4,385**	**4,569**	**4,742**	**4,954**	**0.9%**

Table A8. Electricity supply, disposition, prices, and emissions (continued)
(billion kilowatthours, unless otherwise noted)

Supply, disposition, prices, and emissions	Reference case							Annual growth 2012-2040 (percent)
	2011	2012	2020	2025	2030	2035	2040	
End-use prices								
(2012 cents per kilowatthour)								
Residential	11.9	11.9	12.3	12.3	12.6	12.9	13.3	0.4%
Commercial	10.4	10.1	10.5	10.4	10.7	10.9	11.3	0.4%
Industrial	6.9	6.7	7.1	7.2	7.5	7.8	8.2	0.8%
Transportation	11.6	10.7	10.2	10.3	10.8	11.1	11.7	0.3%
All sectors average	**10.1**	**9.8**	**10.1**	**10.1**	**10.4**	**10.7**	**11.1**	**0.4%**
(nominal cents per kilowatthour)								
Residential	11.7	11.9	14.0	15.2	17.0	19.2	22.0	2.2%
Commercial	10.2	10.1	11.9	12.8	14.4	16.3	18.7	2.2%
Industrial	6.8	6.7	8.0	8.9	10.1	11.6	13.6	2.6%
Transportation	11.4	10.7	11.5	12.6	14.6	16.6	19.3	2.1%
All sectors average	**9.9**	**9.8**	**11.5**	**12.5**	**14.0**	**16.0**	**18.5**	**2.3%**
Prices by service category								
(2012 cents per kilowatthour)								
Generation	5.9	5.7	6.4	6.5	6.8	7.1	7.5	1.0%
Transmission	1.1	1.1	1.1	1.1	1.1	1.1	1.1	0.2%
Distribution	3.1	3.1	2.7	2.6	2.6	2.6	2.6	-0.6%
(nominal cents per kilowatthour)								
Generation	5.8	5.7	7.2	8.0	9.2	10.6	12.4	2.8%
Transmission	1.0	1.1	1.2	1.3	1.5	1.6	1.8	2.0%
Distribution	3.1	3.1	3.1	3.2	3.5	3.8	4.3	1.2%
Electric power sector emissions[1]								
Sulfur dioxide (million short tons)	4.57	3.34	1.38	1.54	1.58	1.59	1.61	-2.6%
Nitrogen oxide (million short tons)	1.94	1.68	1.48	1.56	1.59	1.60	1.60	-0.2%
Mercury (short tons)	30.75	26.35	6.51	6.60	6.69	6.72	6.81	-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 that 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 2012 approximately 7 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 that 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 2011 and 2012 are model results and may differ from official EIA data reports.
Sources: 2011 and 2012 electric power sector generation; sales to the grid; net imports; electricity sales; and electricity end-use prices: U.S. Energy Information Administration (EIA), *Monthly Energy Review*, DOE/EIA-0035(2013/09) (Washington, DC, September 2013), and supporting databases. 2011 and 2012 emissions: U.S. Environmental Protection Agency, Clean Air Markets Database. 2011 and 2012 electricity prices by service category: EIA, AEO2014 National Energy Modeling System run REF2014.D102413A. **Projections**: EIA, AEO2014 National Energy Modeling System run REF2014.D102413A.

Table A9. Electricity generating capacity
(gigawatts)

Net summer capacity[1]	Reference case							Annual growth 2012-2040 (percent)
	2011	2012	2020	2025	2030	2035	2040	
Electric power sector[2]								
Power only[3]								
Coal	307.9	301.9	254.9	254.0	254.0	254.0	254.1	-0.6%
Oil and natural gas steam[4]	103.4	99.2	84.9	77.2	70.9	68.7	68.5	-1.3%
Combined cycle	178.8	186.2	205.1	224.1	259.6	291.0	316.2	1.9%
Combustion turbine/diesel	135.4	136.4	146.3	166.1	180.6	199.5	220.4	1.7%
Nuclear power[5]	101.5	102.1	97.8	97.8	98.2	98.8	102.0	0.0%
Pumped storage	22.3	22.4	22.4	22.4	22.4	22.4	22.4	0.0%
Fuel cells	0.0	0.0	0.1	0.1	0.1	0.1	0.1	1.9%
Renewable sources[6]	133.0	147.6	173.1	175.0	178.2	184.2	199.2	1.1%
Distributed generation (natural gas)[7]	0.0	0.0	1.6	3.3	4.6	6.2	8.9	- -
Total	**982.4**	**996.0**	**986.1**	**1,020.0**	**1,068.6**	**1,124.7**	**1,191.7**	**0.6%**
Combined heat and power[8]								
Coal	4.8	4.7	4.4	4.4	4.4	4.4	4.3	-0.3%
Oil and natural gas steam[4]	1.1	1.1	1.1	1.1	1.1	1.1	1.1	0.0%
Combined cycle	25.6	25.7	26.0	26.0	26.0	26.0	26.0	0.0%
Combustion turbine/diesel	3.3	3.3	3.3	3.3	3.3	3.3	3.3	0.0%
Renewable sources[6]	1.3	1.3	1.4	1.4	1.4	1.4	1.4	0.1%
Total	**36.1**	**36.1**	**36.2**	**36.2**	**36.2**	**36.2**	**36.1**	**0.0%**
Cumulative planned additions[9]								
Coal	- -	- -	2.2	2.2	2.2	2.2	2.2	- -
Oil and natural gas steam[4]	- -	- -	0.0	0.0	0.0	0.0	0.0	- -
Combined cycle	- -	- -	9.7	9.7	9.7	9.7	9.7	- -
Combustion turbine/diesel	- -	- -	3.7	3.7	3.7	3.7	3.7	- -
Nuclear power	- -	- -	5.5	5.5	5.5	5.5	5.5	- -
Pumped storage	- -	- -	0.0	0.0	0.0	0.0	0.0	- -
Fuel cells	- -	- -	0.0	0.0	0.0	0.0	0.0	- -
Renewable sources[6]	- -	- -	9.0	9.0	9.0	9.0	9.0	- -
Distributed generation[7]	- -	- -	0.0	0.0	0.0	0.0	0.0	- -
Total	**- -**	**- -**	**30.1**	**30.1**	**30.1**	**30.1**	**30.1**	**- -**
Cumulative unplanned additions[9]								
Coal	- -	- -	0.3	0.3	0.3	0.3	0.5	- -
Oil and natural gas steam[4]	- -	- -	0.0	0.0	0.0	0.0	0.0	- -
Combined cycle	- -	- -	9.8	28.8	64.3	95.7	120.9	- -
Combustion turbine/diesel	- -	- -	14.1	34.5	49.2	68.5	89.4	- -
Nuclear power	- -	- -	0.0	0.0	0.3	0.9	4.2	- -
Pumped storage	- -	- -	0.0	0.0	0.0	0.0	0.0	- -
Fuel cells	- -	- -	0.0	0.0	0.0	0.0	0.0	- -
Renewable sources[6]	- -	- -	17.4	19.3	22.5	28.5	43.5	- -
Distributed generation[7]	- -	- -	1.6	3.3	4.6	6.2	8.9	- -
Total	**- -**	**- -**	**43.2**	**86.3**	**141.4**	**200.2**	**267.4**	**- -**
Cumulative electric power sector additions[9]	**- -**	**- -**	**73.3**	**116.4**	**171.5**	**230.3**	**297.5**	**- -**
Cumulative retirements[10]								
Coal	- -	- -	49.9	50.7	50.7	50.7	50.8	- -
Oil and natural gas steam[4]	- -	- -	14.4	22.1	28.3	30.6	30.8	- -
Combined cycle	- -	- -	0.3	0.3	0.3	0.3	0.3	- -
Combustion turbine/diesel	- -	- -	7.8	8.5	8.7	9.1	9.2	- -
Nuclear power	- -	- -	4.8	4.8	4.8	4.8	4.8	- -
Pumped storage	- -	- -	0.0	0.0	0.0	0.0	0.0	- -
Fuel cells	- -	- -	0.0	0.0	0.0	0.0	0.0	- -
Renewable sources[6]	- -	- -	0.9	0.9	0.9	0.9	0.9	- -
Total	**- -**	**- -**	**78.0**	**87.3**	**93.8**	**96.4**	**96.7**	**- -**
Total electric power sector capacity	**1,018.5**	**1,032.0**	**1,022.2**	**1,056.2**	**1,104.8**	**1,160.9**	**1,227.8**	**0.6%**

Table A9. Electricity generating capacity (continued)
(gigawatts)

Net summer capacity[1]	Reference case							Annual growth 2012-2040 (percent)
	2011	2012	2020	2025	2030	2035	2040	
End-use generators[11]								
Coal	3.6	3.4	3.4	3.4	3.4	3.4	3.4	0.0%
Petroleum	0.7	0.9	0.9	0.9	0.9	0.9	0.9	-0.3%
Natural gas	14.9	16.3	19.2	22.3	27.3	33.7	38.9	3.2%
Other gaseous fuels[12]	2.0	2.1	2.8	2.8	2.8	2.8	2.8	1.0%
Renewable sources[6]	8.6	10.5	20.5	23.8	28.5	34.3	41.3	5.0%
Other[13]	0.4	0.5	0.5	0.5	0.5	0.5	0.5	0.1%
Total	**30.2**	**33.8**	**47.2**	**53.7**	**63.4**	**75.6**	**87.7**	**3.5%**
Cumulative capacity additions[9]	**- -**	**- -**	**13.5**	**20.0**	**29.7**	**41.8**	**53.9**	**- -**

[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 that have a regulatory status.
[3]Includes plants that only produce electricity and that have a regulatory status. Includes capacity increases (uprates) at existing units.
[4]Includes oil-, gas-, and dual-fired capacity.
[5]Nuclear capacity includes 0.7 gigawatts of uprates and 5.7 gigawatts of derates through 2020.
[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 or that have a regulatory status).
[9]Cumulative additions after December 31, 2012.
[10]Cumulative retirements after December 31, 2012.
[11]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.
[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 2011 and 2012 are model results and may differ from official EIA data reports.
Sources: 2011 and 2012 capacity and projected planned additions: U.S. Energy Information Administration (EIA), Form EIA-860, "Annual Electric Generator Report" (preliminary). **Projections:** EIA, AEO2014 National Energy Modeling System run REF2014.D102413A.

Table A10. Electricity trade
(billion kilowatthours, unless otherwise noted)

Electricity trade	Reference case							Annual growth 2012-2040 (percent)
	2011	2012	2020	2025	2030	2035	2040	
Interregional electricity trade								
Gross domestic sales								
Firm power	161.5	155.8	129.7	65.9	27.6	27.6	27.6	-6.0%
Economy	157.3	174.0	134.7	141.4	194.5	164.9	182.6	0.2%
Total	**318.8**	**329.9**	**264.4**	**207.3**	**222.1**	**192.5**	**210.2**	**-1.6%**
Gross domestic sales (million 2012 dollars)								
Firm power	10,069.9	9,716.3	8,088.6	4,109.8	1,722.5	1,722.5	1,722.5	-6.0%
Economy	7,446.1	6,053.8	6,421.1	7,674.7	11,497.7	10,617.5	12,851.8	2.7%
Total	**17,516.0**	**15,770.1**	**14,509.7**	**11,784.5**	**13,220.2**	**12,340.0**	**14,574.2**	**-0.3%**
International electricity trade								
Imports from Canada and Mexico								
Firm power	15.0	15.9	20.4	16.4	14.0	14.0	14.0	-0.5%
Economy	37.4	43.1	27.9	34.2	35.4	31.0	35.0	-0.7%
Total	**52.4**	**59.0**	**48.3**	**50.6**	**49.3**	**44.9**	**49.0**	**-0.7%**
Exports to Canada and Mexico								
Firm power	2.6	2.7	1.5	0.5	0.0	0.0	0.0	- -
Economy	12.8	8.8	13.9	14.6	14.6	14.3	14.3	1.8%
Total	**15.4**	**11.5**	**15.3**	**15.1**	**14.6**	**14.3**	**14.3**	**0.8%**

- - = Not applicable.
Note: Totals may not equal sum of components due to independent rounding. Data for 2011 and 2012 are model results and may differ 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: 2011 and 2012 interregional firm electricity trade data: 2012 seasonal reliability assessments from North American Electric Reliability Council regional entities and Independent System Operators. 2011 and 2012 interregional economy electricity trade are model results. 2011 and 2012 Mexican electricity trade data: U.S. Energy Information Administration (EIA), *Electric Power Annual 2011*, DOE/EIA-0348(2011) (Washington, DC, January 2013). 2011 Canadian international electricity trade data: National Energy Board, *Electricity Exports and Imports Statistics, 2011*. 2012 Canadian international electricity trade data: National Energy Board, *Electricity Exports and Imports Statistics, 2012*. **Projections:** EIA, AEO2014 National Energy Modeling System run REF2014.D102413A.

Table A11. Petroleum and other liquids supply and disposition
(million barrels per day, unless otherwise noted)

Supply and disposition	Reference case 2011	2012	2020	2025	2030	2035	2040	Annual growth 2012-2040 (percent)
Crude oil								
Domestic crude production[1]	5.66	6.49	9.55	9.00	8.30	7.87	7.48	0.5%
Alaska	0.57	0.53	0.44	0.33	0.24	0.38	0.26	-2.5%
Lower 48 states	5.09	5.96	9.12	8.68	8.06	7.49	7.22	0.7%
Net imports	8.89	8.43	5.79	6.05	6.64	7.15	7.74	-0.3%
Gross imports	8.94	8.49	5.94	6.18	6.77	7.27	7.87	-0.3%
Exports	0.05	0.06	0.15	0.13	0.13	0.12	0.12	2.6%
Other crude supply[2]	0.27	0.09	0.00	0.00	0.00	0.00	0.00	- -
Total crude supply	**14.81**	**15.01**	**15.34**	**15.06**	**14.94**	**15.02**	**15.22**	**0.0%**
Other petroleum supply	**0.85**	**0.10**	**0.23**	**-0.01**	**-0.34**	**-0.67**	**-0.86**	**- -**
Net product imports	-0.25	-0.92	-0.86	-1.01	-1.29	-1.61	-1.82	- -
Gross refined product imports[3]	1.15	0.85	0.98	1.06	1.06	1.08	1.10	0.9%
Unfinished oil imports	0.69	0.60	0.52	0.50	0.49	0.47	0.45	-1.0%
Blending component imports	0.72	0.62	0.62	0.55	0.50	0.45	0.40	-1.5%
Exports	2.81	2.98	2.97	3.12	3.33	3.61	3.76	0.8%
Refinery processing gain[4]	1.08	1.08	1.08	1.00	0.96	0.94	0.95	-0.4%
Product stock withdrawal	0.03	-0.06	0.00	0.00	0.00	0.00	0.00	- -
Other non-petroleum supply	**3.27**	**3.48**	**3.96**	**4.21**	**4.32**	**4.40**	**4.36**	**0.8%**
Supply from renewable sources	0.87	0.89	1.01	1.04	1.04	1.04	1.07	0.7%
Ethanol	0.82	0.83	0.90	0.92	0.91	0.91	0.95	0.5%
Domestic production	0.89	0.84	0.84	0.85	0.86	0.85	0.86	0.1%
Net imports	-0.07	-0.02	0.06	0.06	0.06	0.06	0.08	- -
Stock withdrawal	0.00	0.00	0.00	0.00	0.00	0.00	0.00	- -
Biodiesel	0.06	0.06	0.09	0.09	0.09	0.09	0.09	- -
Domestic production	0.06	0.06	0.08	0.08	0.08	0.08	0.08	0.7%
Net imports	0.00	0.00	0.01	0.01	0.01	0.01	0.01	- -
Stock withdrawal	0.00	0.00	0.00	0.00	0.00	0.00	0.00	- -
Other biomass-derived liquids[5]	0.00	0.00	0.03	0.04	0.04	0.04	0.03	- -
Domestic production	0.00	0.00	0.03	0.04	0.04	0.04	0.03	- -
Net imports	0.00	0.00	0.00	0.00	0.00	0.00	0.00	- -
Stock withdrawal	0.00	0.00	0.00	0.00	0.00	0.00	0.00	- -
Liquids from gas	2.22	2.40	2.65	2.87	2.98	3.05	2.98	0.8%
Natural gas plant liquids	2.22	2.40	2.65	2.87	2.98	3.05	2.98	0.8%
Gas-to-liquids	0.00	0.00	0.00	0.00	0.00	0.00	0.00	- -
Liquids from coal	0.00	0.00	0.00	0.00	0.00	0.00	0.00	- -
Other[6]	0.18	0.19	0.30	0.30	0.30	0.31	0.31	1.8%
Total primary supply[7]	**18.94**	**18.59**	**19.52**	**19.26**	**18.93**	**18.75**	**18.72**	**0.0%**
Product supplied								
by fuel								
Liquefied petroleum gases and other[8]	2.30	2.32	2.73	2.84	2.84	2.78	2.73	0.6%
Motor gasoline[9]	8.75	8.71	8.35	7.67	7.15	6.91	6.84	-0.9%
of which: E85[10]	0.00	0.01	0.13	0.26	0.32	0.30	0.23	11.9%
Jet fuel[11]	1.43	1.40	1.49	1.52	1.55	1.57	1.59	0.5%
Distillate fuel oil[12]	3.90	3.74	4.30	4.44	4.52	4.59	4.62	0.8%
of which: Diesel	3.51	3.45	3.94	4.11	4.21	4.30	4.34	0.8%
Residual fuel oil	0.46	0.35	0.39	0.39	0.40	0.40	0.40	0.6%
Other[13]	2.08	1.97	2.28	2.40	2.49	2.51	2.55	0.9%
by sector								
Residential and commercial	0.97	0.94	0.88	0.84	0.81	0.78	0.76	-0.8%
Industrial[14]	4.45	4.42	5.37	5.64	5.72	5.70	5.68	0.9%
Transportation	13.65	13.44	13.19	12.71	12.32	12.20	12.20	-0.3%
Electric power[15]	0.14	0.10	0.08	0.08	0.08	0.08	0.08	-0.7%
Total	**18.92**	**18.49**	**19.53**	**19.27**	**18.94**	**18.76**	**18.73**	**0.0%**
Discrepancy[16]	0.02	0.11	-0.01	-0.01	-0.01	-0.01	-0.01	- -

Table A11. Petroleum and other liquids supply and disposition (continued)
(million barrels per day, unless otherwise noted)

Supply and disposition	Reference case							Annual growth 2012-2040 (percent)
	2011	2012	2020	2025	2030	2035	2040	
Domestic refinery distillation capacity[17]	17.7	17.3	18.1	18.1	18.1	18.1	18.1	0.2%
Capacity utilization rate (percent)[18]	86.0	89.0	84.6	83.1	82.4	82.9	84.0	-0.2%
Net import share of product supplied (percent)	45.2	40.3	25.6	26.6	28.6	29.9	32.2	-0.8%
Net expenditures for imported crude oil and petroleum products (billion 2012 dollars)	494.73	313.70	198.85	234.27	278.60	327.33	385.39	0.7%

[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]Includes ethane, natural gasoline, and refinery olefins.
[9]Includes ethanol and ethers blended into gasoline.
[10]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.
[11]Includes only kerosene type.
[12]Includes distillate fuel oil from petroleum and biomass feedstocks.
[13]Includes kerosene, aviation gasoline, petrochemical feedstocks, lubricants, waxes, asphalt, road oil, still gas, special naphthas, petroleum coke, crude oil product supplied, methanol, and miscellaneous petroleum products.
[14]Includes energy for combined heat and power plants that have a non-regulatory status, and small on-site generating systems.
[15]Includes consumption of energy by electricity-only and combined heat and power plants that have a regulatory status.
[16]Balancing item. Includes unaccounted for supply, losses, and gains.
[17]End-of-year operable capacity.
[18]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 2011 and 2012 are model results and may differ from official EIA data reports.
Sources: 2011 and 2012 product supplied based on: U.S. Energy Information Administration (EIA), *Monthly Energy Review*, DOE/EIA-0035(2013/09) (Washington, DC, September 2013). Other 2011 data: EIA, *Petroleum Supply Annual 2011*, DOE/EIA-0340(2011)/1 (Washington, DC, August 2012). Other 2012 data: EIA, *Petroleum Supply Annual 2012*, DOE/EIA-0340(2012)/1 (Washington, DC, September 2013). **Projections:** EIA, AEO2014 National Energy Modeling System run REF2014.D102413A.

Table A12. Petroleum and other liquids prices
(2012 dollars per gallon, unless otherwise noted)

Sector and fuel	Reference case							Annual growth 2012-2040 (percent)
	2011	2012	2020	2025	2030	2035	2040	
Crude oil prices (2012 dollars per barrel)								
Brent spot	113.24	111.65	96.57	108.99	118.99	129.77	141.46	0.8%
West Texas Intermediate spot	96.55	94.12	94.57	106.99	116.99	127.77	139.46	1.4%
Average imported refiners acquisition cost[1]	104.47	101.10	88.07	100.01	109.22	119.80	130.80	0.9%
Delivered sector product prices								
Residential								
Propane	2.31	2.20	2.17	2.27	2.35	2.45	2.52	0.5%
Distillate fuel oil	3.73	3.79	3.42	3.74	3.97	4.24	4.53	0.6%
Commercial								
Distillate fuel oil	3.64	3.70	3.00	3.31	3.54	3.82	4.10	0.4%
Residual fuel oil	2.91	3.42	2.16	2.41	2.68	2.90	3.14	-0.3%
Residual fuel oil (2012 dollars per barrel)	122.01	143.59	90.53	101.42	112.66	121.75	131.97	-0.3%
Industrial[2]								
Propane	2.07	1.93	1.89	2.02	2.13	2.26	2.36	0.7%
Distillate fuel oil	3.71	3.76	3.05	3.36	3.58	3.84	4.11	0.3%
Residual fuel oil	2.87	3.13	2.23	2.49	2.74	2.96	3.22	0.1%
Residual fuel oil (2012 dollars per barrel)	120.55	131.40	93.56	104.67	115.00	124.42	135.04	0.1%
Transportation								
Propane	2.40	2.30	2.27	2.37	2.45	2.56	2.63	0.5%
Ethanol (E85)[3]	4.19	3.33	2.43	2.62	2.65	2.92	3.37	0.0%
Ethanol wholesale price	2.58	2.58	2.66	2.61	2.52	2.43	2.65	0.1%
Motor gasoline[4]	3.65	3.69	3.08	3.29	3.43	3.65	3.90	0.2%
Jet fuel[5]	3.11	3.10	2.63	2.96	3.20	3.49	3.79	0.7%
Diesel fuel (distillate fuel oil)[6]	3.89	3.95	3.67	3.98	4.20	4.47	4.73	0.7%
Residual fuel oil	2.70	3.00	1.86	2.12	2.32	2.54	2.78	-0.3%
Residual fuel oil (2012 dollars per barrel)	113.46	126.17	78.31	89.03	97.43	106.50	116.65	-0.3%
Electric power[7]								
Distillate fuel oil	3.30	3.35	2.87	3.18	3.42	3.70	4.00	0.6%
Residual fuel oil	2.39	3.10	2.07	2.33	2.57	2.81	3.06	0.0%
Residual fuel oil (2012 dollars per barrel)	100.25	130.00	87.12	98.04	107.77	117.85	128.40	0.0%
Average prices, all sectors[8]								
Propane	2.23	2.12	2.06	2.16	2.25	2.36	2.45	0.5%
Motor gasoline[4]	3.63	3.66	3.08	3.29	3.43	3.65	3.90	0.2%
Jet fuel[5]	3.11	3.10	2.63	2.96	3.20	3.49	3.79	0.7%
Distillate fuel oil	3.83	3.89	3.53	3.84	4.07	4.33	4.60	0.6%
Residual fuel oil	2.66	3.05	1.97	2.23	2.44	2.66	2.91	-0.2%
Residual fuel oil (2012 dollars per barrel)	111.89	128.30	82.69	93.53	102.60	111.83	122.12	-0.2%
Average	**3.28**	**3.28**	**2.80**	**3.02**	**3.19**	**3.43**	**3.69**	**0.4%**

Table A12. Petroleum and other liquids prices (continued)
(nominal dollars per gallon, unless otherwise noted)

Sector and fuel	Reference case							Annual growth 2012-2040 (percent)
	2011	2012	2020	2025	2030	2035	2040	
Crude oil spot prices (nominal dollars per barrel)								
Brent spot	111.26	111.65	109.37	134.25	160.19	193.27	234.53	2.7%
West Texas Intermediate spot	94.86	94.12	107.11	131.78	157.49	190.30	231.22	3.3%
Average imported refiners acquisition cost[1]	102.64	101.10	99.75	123.19	147.02	178.43	216.87	2.8%
Delivered sector product prices								
Residential								
Propane	2.27	2.20	2.46	2.80	3.17	3.65	4.19	2.3%
Distillate fuel oil	3.67	3.79	3.88	4.60	5.34	6.31	7.51	2.5%
Commercial								
Distillate fuel oil	3.58	3.70	3.40	4.08	4.76	5.69	6.79	2.2%
Residual fuel oil	2.85	3.42	2.44	2.97	3.61	4.32	5.21	1.5%
Residual fuel oil (nominal dollars per barrel)	119.88	143.59	102.54	124.92	151.65	181.33	218.81	1.5%
Industrial[2]								
Propane	2.03	1.93	2.14	2.48	2.86	3.36	3.91	2.6%
Distillate fuel oil	3.65	3.76	3.46	4.13	4.82	5.72	6.81	2.1%
Residual fuel oil	2.82	3.13	2.52	3.07	3.69	4.41	5.33	1.9%
Residual fuel oil (nominal dollars per barrel)	118.44	131.40	105.96	128.93	154.81	185.30	223.89	1.9%
Transportation								
Propane	2.36	2.30	2.57	2.92	3.30	3.81	4.36	2.3%
Ethanol (E85)[3]	4.11	3.33	2.76	3.22	3.57	4.34	5.59	1.9%
Ethanol wholesale price	2.54	2.58	3.02	3.21	3.39	3.63	4.39	1.9%
Motor gasoline[4]	3.58	3.69	3.49	4.05	4.61	5.43	6.47	2.0%
Jet fuel[5]	3.05	3.10	2.98	3.65	4.31	5.19	6.28	2.5%
Diesel fuel (distillate fuel oil)[6]	3.82	3.95	4.16	4.90	5.66	6.65	7.84	2.5%
Residual fuel oil	2.65	3.00	2.11	2.61	3.12	3.78	4.60	1.5%
Residual fuel oil (nominal dollars per barrel)	111.48	126.17	88.69	109.66	131.15	158.62	193.40	1.5%
Electric power[7]								
Distillate fuel oil	3.24	3.35	3.25	3.92	4.60	5.51	6.62	2.5%
Residual fuel oil	2.35	3.10	2.35	2.88	3.45	4.18	5.07	1.8%
Residual fuel oil (nominal dollars per barrel)	98.49	130.00	98.67	120.77	145.08	175.52	212.89	1.8%
Average prices, all sectors[8]								
Propane	2.19	2.12	2.33	2.66	3.03	3.52	4.06	2.3%
Motor gasoline[4]	3.57	3.66	3.49	4.05	4.61	5.43	6.47	2.1%
Jet fuel[5]	3.05	3.10	2.98	3.65	4.31	5.19	6.28	2.5%
Distillate fuel oil	3.77	3.89	3.99	4.73	5.48	6.45	7.63	2.4%
Residual fuel oil	2.62	3.05	2.23	2.74	3.29	3.97	4.82	1.6%
Residual fuel oil (nominal dollars per barrel)	109.93	128.30	93.65	115.20	138.12	166.56	202.47	1.6%
Average	**3.22**	**3.28**	**3.17**	**3.72**	**4.30**	**5.11**	**6.11**	**2.2%**

[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 and 2012 are model results and may differ from official EIA data reports.
Sources: 2011 and 2012 Brent and West Texas Intermediate crude oil spot prices: Thomson Reuters. 2011 and 2012 average imported crude oil cost: U.S. Energy Information Administration (EIA), *Monthly Energy Review*, DOE/EIA-0035(2013/09) (Washington, DC, September 2013). 2011 and 2012 prices for motor gasoline, distillate fuel oil, and jet fuel are based on: EIA, *Petroleum Marketing Monthly*, DOE/EIA-0380(2013/08) (Washington, DC, August 2013). 2011 and 2012 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 and 2012 electric power prices based on: EIA, *Monthly Energy Review*, DOE/EIA-0035(2013/09) (Washington, DC, September 2013). 2011 and 2012 E85 prices derived from monthly prices in the Clean Cities Alternative Fuel Price Report. 2011 and 2012 wholesale ethanol prices derived from Bloomberg U.S. average rack price. **Projections:** EIA, AEO2014 National Energy Modeling System run REF2014.D102413A.

Table A13. Natural gas supply, disposition, and prices
(trillion cubic feet per year, unless otherwise noted)

Supply, disposition, and prices	Reference case							Annual growth 2012-2040 (percent)
	2011	2012	2020	2025	2030	2035	2040	
Supply								
Dry gas production[1]	22.55	24.06	29.09	31.86	34.43	36.09	37.54	1.6%
Supplemental natural gas[2]	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.1%
Net imports	1.96	1.51	-1.93	-3.41	-4.94	-5.53	-5.80	- -
Pipeline[3]	1.68	1.37	0.00	-0.84	-1.57	-2.16	-2.43	- -
Liquefied natural gas	0.28	0.15	-1.93	-2.57	-3.37	-3.37	-3.37	- -
Total supply	**24.57**	**25.64**	**27.23**	**28.52**	**29.56**	**30.63**	**31.81**	**0.8%**
Consumption by sector								
Residential	4.71	4.17	4.46	4.40	4.33	4.23	4.12	0.0%
Commercial	3.16	2.90	3.16	3.22	3.28	3.40	3.57	0.7%
Industrial[4]	6.90	7.14	8.09	8.41	8.52	8.59	8.68	0.7%
Natural-gas-to-liquids heat and power[5]	0.00	0.00	0.00	0.00	0.00	0.00	0.00	- -
Natural gas to liquids production[6]	0.00	0.00	0.00	0.00	0.00	0.00	0.00	- -
Electric power[7]	7.56	9.25	8.81	9.49	10.06	10.67	11.23	0.7%
Transportation[8]	0.04	0.04	0.08	0.14	0.28	0.48	0.85	11.3%
Pipeline fuel	0.68	0.72	0.73	0.75	0.80	0.82	0.83	0.5%
Lease and plant fuel[9]	1.32	1.42	1.74	1.95	2.11	2.24	2.35	1.8%
Total consumption	**24.38**	**25.64**	**27.06**	**28.35**	**29.39**	**30.44**	**31.63**	**0.8%**
Discrepancy[10]	**0.19**	**0.00**	**0.17**	**0.17**	**0.17**	**0.19**	**0.18**	**- -**
Natural gas spot price at Henry Hub								
(2012 dollars per million Btu)	**4.07**	**2.75**	**4.38**	**5.23**	**6.03**	**6.92**	**7.65**	**3.7%**
(nominal dollars per million Btu)	**4.00**	**2.75**	**4.96**	**6.45**	**8.12**	**10.31**	**12.69**	**5.6%**
Delivered natural gas prices								
(2012 dollars per thousand cubic feet)								
Residential	11.22	10.69	11.85	12.75	13.80	14.93	16.33	1.5%
Commercial	9.16	8.29	9.70	10.51	11.44	12.22	13.37	1.7%
Industrial[4]	5.21	3.85	5.92	6.46	7.14	7.93	8.78	3.0%
Electric power[7]	4.98	3.51	5.19	5.88	6.64	7.45	8.34	3.1%
Transportation[11]	16.25	14.96	15.96	15.91	16.99	18.49	20.10	1.1%
Average[12]	**6.98**	**5.50**	**7.25**	**7.89**	**8.68**	**9.54**	**10.61**	**2.4%**
(nominal dollars per thousand cubic feet)								
Residential	11.02	10.69	13.42	15.70	18.58	22.23	27.07	3.4%
Commercial	9.00	8.29	10.99	12.95	15.40	18.20	22.16	3.6%
Industrial[4]	5.11	3.85	6.70	7.96	9.62	11.81	14.56	4.9%
Electric power[7]	4.90	3.51	5.87	7.25	8.93	11.09	13.82	5.0%
Transportation[11]	15.97	14.96	18.08	19.60	22.87	27.54	33.33	2.9%
Average[12]	**6.86**	**5.50**	**8.21**	**9.71**	**11.68**	**14.21**	**17.59**	**4.2%**

[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 fuel in motor vehicles, trains, and ships.
[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, 2011 and 2012 values include net storage injections.
[11]Natural gas used as fuel in motor vehicles, trains, and ships. 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 2011 and 2012 are model results and may differ from official EIA data reports.
Sources: 2011 supply values; lease, plant, and pipeline fuel consumption; and residential, commercial, and industrial delivered prices: U.S. Energy Information Administration (EIA), *Natural Gas Annual 2011*, DOE/EIA-0131(2011) (Washington, DC, December 2012). 2012 supply values; lease, plant, and pipeline fuel consumption; and residential, commercial, and industrial delivered prices: EIA, *Natural Gas Monthly*, DOE/EIA-0130(2013/06) (Washington, DC, June 2013). Other 2011 and 2012 consumption based on: EIA, *Monthly Energy Review*, DOE/EIA-0035(2013/09) (Washington, DC, September 2013). 2011 and 2012 natural gas spot price at Henry Hub: Thomson Reuters. 2011 and 2012 electric power prices: EIA, *Electric Power Monthly*, DOE/EIA-0226, April 2012 and April 2013, Table 4.2, and EIA, *State Energy Data Report 2011*, DOE/EIA-0214(2011) (Washington, DC, June 2013). 2011 transportation sector delivered prices are based on: EIA, *Natural Gas Annual 2011*, DOE/EIA-0131(2011) (Washington, DC, December 2012) and estimated state taxes, federal taxes, and dispensing costs or charges. 2012 transportation sector delivered prices are model results. **Projections:** EIA, AEO2014 National Energy Modeling System run REF2014.D102413A.

Table A14. Oil and gas supply

Production and supply	Reference case 2011	2012	2020	2025	2030	2035	2040	Annual growth 2012-2040 (percent)
Crude oil								
Lower 48 average wellhead price[1] (2012 dollars per barrel)	**98.12**	**94.94**	**92.93**	**104.90**	**114.69**	**125.59**	**137.63**	**1.3%**
Production (million barrels per day)[2]								
United States total	5.66	6.49	9.55	9.00	8.30	7.87	7.48	0.5%
Lower 48 onshore	3.66	4.60	7.21	7.04	6.38	5.79	5.23	0.5%
Tight oil[3]	1.31	2.25	4.79	4.54	4.17	3.69	3.20	1.3%
Carbon dioxide enhanced oil recovery	0.28	0.28	0.36	0.47	0.58	0.66	0.74	3.6%
Other	2.07	2.07	2.06	2.03	1.63	1.44	1.29	-1.7%
Lower 48 offshore	1.43	1.37	1.90	1.64	1.68	1.70	1.99	1.4%
Alaska	0.57	0.53	0.44	0.33	0.24	0.38	0.26	-2.5%
Lower 48 end of year reserves[2] (billion barrels)	**25.10**	**24.71**	**31.78**	**33.01**	**34.42**	**34.58**	**35.45**	**1.3%**
Natural gas plant liquids production (million barrels per day)								
United States total	2.22	2.40	2.65	2.87	2.98	3.05	2.98	0.8%
Lower 48 onshore	0.00	2.31	2.42	2.66	2.75	2.81	2.71	0.6%
Lower 48 offshore	0.15	0.14	0.20	0.19	0.22	0.22	0.26	2.3%
Alaska	0.05	0.05	0.03	0.02	0.01	0.02	0.02	-4.1%
Natural gas								
Natural gas spot price at Henry Hub (2012 dollars per million Btu)	4.07	2.75	4.38	5.23	6.03	6.92	7.65	3.7%
Dry production (trillion cubic feet)[4]								
United States total	22.55	24.06	29.09	31.86	34.43	36.09	37.54	1.6%
Lower 48 onshore	20.35	22.07	26.65	29.52	30.82	32.46	33.43	1.5%
Associated-dissolved[5]	1.67	2.06	2.65	2.60	2.25	2.06	1.91	-0.3%
Non-associated	18.68	20.02	24.00	26.92	28.57	30.39	31.52	1.6%
Tight gas	5.01	4.86	6.48	7.06	8.06	8.53	8.41	2.0%
Shale gas	7.94	9.72	13.33	15.99	16.92	18.50	19.82	2.6%
Coalbed methane	1.73	1.58	1.66	1.61	1.61	1.64	1.71	0.3%
Other	4.00	3.86	2.53	2.25	1.98	1.72	1.58	-3.1%
Lower 48 offshore	1.86	1.66	2.16	2.09	2.42	2.46	2.95	2.1%
Associated-dissolved[5]	0.51	0.48	0.68	0.56	0.58	0.59	0.71	1.4%
Non-associated	1.35	1.18	1.48	1.53	1.84	1.87	2.24	2.3%
Alaska	0.33	0.33	0.28	0.26	1.19	1.17	1.17	4.6%
Lower 48 end of year dry reserves[4] (trillion cubic feet)	**324.64**	**320.09**	**352.47**	**368.52**	**382.58**	**393.60**	**402.59**	**0.8%**
Supplemental gas supplies (trillion cubic feet)[6]	**0.06**	**0.06**	**0.06**	**0.06**	**0.06**	**0.06**	**0.06**	**0.1%**
Total lower 48 wells drilled (thousands)	**41.81**	**42.49**	**50.46**	**60.06**	**59.28**	**61.73**	**61.57**	**1.3%**

[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 2011 and 2012 are model results and may differ from official EIA data reports.
Sources: 2011 and 2012 crude oil lower 48 average wellhead price: U.S. Energy Information Administration (EIA), *Petroleum Marketing Monthly*, DOE/EIA-0380(2013/08) (Washington, DC, August 2013). 2011 and 2012 lower 48 onshore, lower 48 offshore, and Alaska crude oil production: EIA, *Petroleum Supply Annual 2012*, DOE/EIA-0340(2012)/1 (Washington, DC, September 2013). 2011 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). 2011 Alaska and total natural gas production, and supplemental gas supplies: EIA, *Natural Gas Annual 2011*, DOE/EIA-0131(2011) (Washington, DC, December 2012). 2011 and 2012 natural gas spot price at Henry Hub: Thomson Reuters. 2012 Alaska and total natural gas production, and supplemental gas supplies: EIA, *Natural Gas Monthly*, DOE/EIA-0130(2013/06) (Washington, DC, June 2013). Other 2011 and 2012 values: EIA, Office of Energy Analysis. **Projections:** EIA, AEO2014 National Energy Modeling System run REF2014.D102413A.

Table A15. Coal supply, disposition, and prices
(million short tons per year, unless otherwise noted)

Supply, disposition, and prices	Reference case 2011	2012	2020	2025	2030	2035	2040	Annual growth 2012-2040 (percent)
Production[1]								
Appalachia	337	293	261	259	253	253	247	-0.6%
Interior	171	180	228	244	266	279	289	1.7%
West	588	543	587	611	607	594	584	0.3%
East of the Mississippi	456	423	438	446	459	471	475	0.4%
West of the Mississippi	639	593	639	668	668	655	645	0.3%
Total	**1,096**	**1,016**	**1,077**	**1,114**	**1,127**	**1,126**	**1,121**	**0.3%**
Waste coal supplied[2]	**13**	**11**	**14**	**14**	**15**	**17**	**19**	**1.9%**
Net imports								
Imports[3]	11	8	2	2	1	2	1	-6.6%
Exports	107	126	128	136	148	160	161	0.9%
Total	**-96**	**-118**	**-126**	**-135**	**-147**	**-158**	**-160**	**1.1%**
Total supply[4]	**1,013**	**909**	**965**	**993**	**995**	**985**	**979**	**0.3%**
Consumption by sector								
Commercial and institutional	3	2	2	2	2	2	2	-0.1%
Coke plants	21	21	22	22	21	19	18	-0.5%
Other industrial[5]	46	43	49	49	49	49	50	0.5%
Coal-to-liquids heat and power	0	0	0	0	0	0	0	- -
Coal to liquids production	0	0	0	0	0	0	0	- -
Electric power[6]	932	825	892	919	923	915	909	0.3%
Total	**1,003**	**891**	**965**	**993**	**995**	**985**	**979**	**0.3%**
Discrepancy and stock change[7]	**10**	**19**	**0**	**0**	**0**	**0**	**0**	**- -**
Average minemouth price[8]								
(2012 dollars per short ton)	41.74	39.94	46.52	49.67	53.15	56.37	59.16	1.4%
(2012 dollars per million Btu)	2.07	1.98	2.33	2.49	2.67	2.82	2.96	1.4%
Delivered prices[9]								
(2012 dollars per short ton)								
Commercial and institutional	93.58	90.76	95.19	97.75	101.39	104.53	108.37	0.6%
Coke plants	187.72	190.55	221.01	234.75	249.43	260.42	267.23	1.2%
Other industrial[5]	71.87	70.32	76.39	79.29	82.64	85.75	89.22	0.9%
Coal to liquids	- -	- -	- -	- -	- -	- -	- -	- -
Electric power[6]								
(2012 dollars per short ton)	47.06	46.13	49.63	52.56	55.32	57.76	60.61	1.0%
(2012 dollars per million Btu)	2.42	2.39	2.61	2.77	2.93	3.05	3.19	1.0%
Average	**51.36**	**50.85**	**54.99**	**58.06**	**60.85**	**63.22**	**65.97**	**0.9%**
Exports[10]	151.51	118.43	136.76	142.74	145.97	148.56	150.13	0.9%

Table A15. Coal supply, disposition, and prices (continued)

(million short tons per year, unless otherwise noted)

Supply, disposition, and prices	Reference case							Annual growth 2012-2040 (percent)
	2011	2012	2020	2025	2030	2035	2040	
Average minemouth price[8]								
(nominal dollars per short ton)	41.01	39.94	52.69	61.18	71.55	83.96	98.08	3.3%
(nominal dollars per million Btu)	2.04	1.98	2.63	3.07	3.59	4.21	4.91	3.3%
Delivered prices[9]								
(nominal dollars per short ton)								
Commercial and institutional	91.94	90.76	107.81	120.40	136.49	155.69	179.68	2.5%
Coke plants	184.44	190.55	250.32	289.16	335.77	387.86	443.06	3.1%
Other industrial[5]	70.61	70.32	86.52	97.66	111.25	127.72	147.92	2.7%
Coal to liquids	- -	- -	- -	- -	- -	- -	- -	- -
Electric power[6]								
(nominal dollars per short ton)	46.24	46.13	56.21	64.74	74.47	86.03	100.48	2.8%
(nominal dollars per million Btu)	2.38	2.39	2.96	3.42	3.94	4.54	5.29	2.9%
Average	**50.46**	**50.85**	**62.28**	**71.52**	**81.91**	**94.16**	**109.37**	**2.8%**
Exports[10]	148.86	118.43	154.90	175.82	196.51	221.27	248.92	2.7%

[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 prices.
[10]Free-alongside-ship 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 2011 and 2012 are model results and may differ from official EIA data reports.
Sources: 2011 and 2012 data based on: U.S. Energy Information Administration (EIA), *Annual Coal Report 2012*, DOE/EIA-0584(2012) (Washington, DC, December 2013); EIA, *Quarterly Coal Report, October-December 2012*, DOE/EIA-0121(2012/4Q) (Washington, DC, March 2013); and EIA, AEO2014 National Energy Modeling System run REF2014.D102413A. **Projections:** EIA, AEO2014 National Energy Modeling System run REF2014.D102413A.

Table A16. Renewable energy generating capacity and generation
(gigawatts, unless otherwise noted)

Net summer capacity and generation	Reference case							Annual growth 2012-2040 (percent)
	2011	2012	2020	2025	2030	2035	2040	
Electric power sector[1]								
Net summer capacity								
Conventional hydropower	77.96	78.10	78.41	79.10	79.75	80.07	80.35	0.1%
Geothermal[2]	2.45	2.58	4.02	5.15	6.58	7.99	8.80	4.5%
Municipal waste[3]	3.45	3.57	3.63	3.63	3.63	3.63	3.63	0.1%
Wood and other biomass[4]	2.56	2.70	3.14	3.14	3.14	3.17	3.46	0.9%
Solar thermal	0.48	0.48	1.73	1.73	1.73	1.73	1.73	4.7%
Solar photovoltaic[5]	1.05	2.49	7.90	7.96	8.62	10.33	17.07	7.1%
Wind	46.33	59.01	75.59	75.62	76.12	78.61	85.48	1.3%
Offshore wind	0.00	0.00	0.00	0.00	0.00	0.00	0.00	- -
Total electric power sector capacity	**134.28**	**148.92**	**174.43**	**176.32**	**179.56**	**185.54**	**200.52**	**1.1%**
Generation (billion kilowatthours)								
Conventional hydropower	316.65	273.89	287.67	291.17	294.35	296.14	297.34	0.3%
Geothermal[2]	15.32	15.56	28.24	37.44	49.04	60.60	67.26	5.4%
Biogenic municipal waste[6]	16.20	16.79	19.05	18.19	18.15	18.66	19.21	0.5%
Wood and other biomass	10.73	11.04	36.71	58.87	67.50	70.39	72.22	6.9%
Dedicated plants	9.55	9.84	15.31	15.95	16.17	16.80	18.99	2.4%
Cofiring	1.19	1.20	21.40	42.92	51.33	53.59	53.23	14.5%
Solar thermal	0.81	0.90	3.52	3.53	3.53	3.53	3.53	5.0%
Solar photovoltaic[5]	0.92	3.25	14.54	14.65	16.07	19.86	35.24	8.9%
Wind	120.12	141.87	217.53	217.62	219.06	225.11	248.02	2.0%
Offshore wind	0.00	0.00	0.00	0.00	0.00	0.00	0.00	- -
Total electric power sector generation	**480.74**	**463.29**	**607.26**	**641.47**	**667.71**	**694.30**	**742.82**	**1.7%**
End-use sectors[7]								
Net summer capacity								
Conventional hydropower	0.33	0.29	0.29	0.29	0.29	0.29	0.29	0.0%
Geothermal	0.00	0.00	0.00	0.00	0.00	0.00	0.00	- -
Municipal waste[8]	0.37	0.47	0.47	0.47	0.47	0.47	0.47	0.0%
Biomass	4.85	4.89	6.27	7.17	7.95	8.74	9.62	2.4%
Solar photovoltaic[5]	2.89	4.71	12.75	15.18	18.93	23.73	29.47	6.8%
Wind	0.14	0.15	0.70	0.74	0.90	1.09	1.42	8.3%
Total end-use sector capacity	**8.58**	**10.51**	**20.48**	**23.84**	**28.53**	**34.31**	**41.26**	**5.0%**
Generation (billion kilowatthours)								
Conventional hydropower	1.82	1.38	1.38	1.38	1.38	1.38	1.38	0.0%
Geothermal	0.00	0.00	0.00	0.00	0.00	0.00	0.00	- -
Municipal waste[8]	2.91	3.65	3.63	3.63	3.63	3.63	3.63	0.0%
Biomass	26.69	26.53	34.10	39.18	43.75	48.37	53.50	2.5%
Solar photovoltaic[5]	4.51	7.35	19.91	23.92	30.09	38.00	47.46	6.9%
Wind	0.18	0.20	0.96	1.03	1.25	1.53	2.01	8.6%
Total end-use sector generation	**36.11**	**39.11**	**59.98**	**69.14**	**80.10**	**92.91**	**107.99**	**3.7%**

Table A16. Renewable energy generating capacity and generation (continued)
(gigawatts, unless otherwise noted)

Net summer capacity and generation	Reference case							Annual growth 2012-2040 (percent)
	2011	2012	2020	2025	2030	2035	2040	
Total, all sectors								
Net summer capacity								
Conventional hydropower	78.29	78.39	78.70	79.39	80.03	80.36	80.63	0.1%
Geothermal	2.45	2.58	4.02	5.15	6.58	7.99	8.80	4.5%
Municipal waste	3.82	4.04	4.10	4.10	4.10	4.10	4.10	0.1%
Wood and other biomass[4]	7.42	7.59	9.41	10.30	11.08	11.91	13.08	2.0%
Solar[5]	4.42	7.68	22.38	24.86	29.27	35.78	48.26	6.8%
Wind	46.47	59.16	76.29	76.37	77.02	79.70	86.91	1.4%
Total capacity, all sectors	**142.86**	**159.43**	**194.91**	**200.17**	**208.09**	**219.85**	**241.78**	**1.5%**
Generation (billion kilowatthours)								
Conventional hydropower	318.47	275.27	289.05	292.55	295.73	297.52	298.72	0.3%
Geothermal	15.32	15.56	28.24	37.44	49.04	60.60	67.26	5.4%
Municipal waste	19.11	20.44	22.68	21.82	21.78	22.29	22.84	0.4%
Wood and other biomass	37.42	37.57	70.81	98.06	111.25	118.76	125.72	4.4%
Solar[5]	6.24	11.50	37.98	42.09	49.69	61.40	86.23	7.5%
Wind	120.30	142.06	218.49	218.64	220.32	226.65	250.03	2.0%
Total generation, all sectors	**516.85**	**502.41**	**667.24**	**710.61**	**747.81**	**787.22**	**850.80**	**1.9%**

[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 2012, EIA estimates that as much as 274 megawatts of remote electricity generation PV applications (i.e., off-grid power systems) were in service in 2012, plus an additional 573 megawatts in communications, transportation, and assorted other non-grid-connected, specialized applications. See U.S. Energy Information Administration, *Annual Energy Review 2011*, DOE/EIA-0384(2011) (Washington, DC, September 2012), Table 10.9 (annual PV shipments, 1989-2010), and Table 12 (U.S. photovoltaic module shipments by end use, sector, and type) in U.S. Energy Information Administration, *Solar Photovoltaic Cell/Module Shipments Report, 2011* (Washington, DC, September 2012) and U.S. Energy Information Administration, *Solar Photovoltaic Cell/Module Shipments Report, 2012* (Washington, DC, December 2013). 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 2012 approximately 7 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 2011 and 2012 are model results and may differ from official EIA data reports.
Sources: 2011 and 2012 capacity: U.S. Energy Information Administration (EIA), Form EIA-860, "Annual Electric Generator Report" (preliminary). 2011 and 2012 generation: EIA, *Monthly Energy Review*, DOE/EIA-0035(2013/09) (Washington, DC, September 2013). **Projections:** EIA, AEO2014 National Energy Modeling System run REF2014.D102413A.

Table A17. Renewable energy consumption by sector and source
(quadrillion Btu per year)

Sector and source	Reference case							Annual growth 2012-2040 (percent)
	2011	2012	2020	2025	2030	2035	2040	
Marketed renewable energy[1]								
Residential (wood)	**0.54**	**0.45**	**0.46**	**0.45**	**0.44**	**0.43**	**0.42**	**-0.3%**
Commercial (biomass)	**0.11**	**0.13**	**0.13**	**0.13**	**0.13**	**0.13**	**0.13**	**0.0%**
Industrial[2]	**1.95**	**2.00**	**2.50**	**2.67**	**2.79**	**2.92**	**3.07**	**1.5%**
Conventional hydroelectric	0.02	0.01	0.01	0.01	0.01	0.01	0.01	0.0%
Municipal waste[3]	0.17	0.19	0.20	0.20	0.20	0.20	0.20	0.2%
Biomass	1.30	1.28	1.53	1.67	1.80	1.92	2.07	1.7%
Biofuels heat and coproducts	0.46	0.52	0.76	0.79	0.79	0.79	0.79	1.5%
Transportation	**1.21**	**1.22**	**1.42**	**1.45**	**1.45**	**1.45**	**1.49**	**0.7%**
Ethanol used in E85[4]	0.00	0.01	0.13	0.25	0.31	0.29	0.22	11.9%
Ethanol used in gasoline blending	1.09	1.09	1.07	0.97	0.91	0.93	1.04	-0.2%
Biodiesel used in distillate blending	0.12	0.12	0.17	0.17	0.17	0.17	0.17	1.5%
Biobutanol	0.00	0.00	0.03	0.04	0.04	0.04	0.03	- -
Liquids from biomass	0.00	0.00	0.01	0.01	0.01	0.01	0.01	- -
Renewable diesel and gasoline[5]	0.00	0.00	0.01	0.01	0.01	0.01	0.01	- -
Electric power[6]	**4.80**	**4.59**	**6.08**	**6.42**	**6.68**	**6.95**	**7.44**	**1.7%**
Conventional hydroelectric	3.09	2.66	2.79	2.83	2.86	2.88	2.89	0.3%
Geothermal	0.15	0.15	0.28	0.36	0.48	0.59	0.65	5.4%
Biogenic municipal waste[7]	0.19	0.21	0.25	0.23	0.23	0.24	0.25	0.6%
Biomass	0.18	0.15	0.47	0.70	0.79	0.83	0.86	6.5%
Dedicated plants	0.16	0.16	0.24	0.25	0.26	0.27	0.30	2.3%
Cofiring	0.03	-0.01	0.23	0.45	0.54	0.56	0.56	- -
Solar thermal	0.01	0.01	0.03	0.03	0.03	0.03	0.03	5.0%
Solar photovoltaic	0.01	0.03	0.14	0.14	0.16	0.19	0.34	8.9%
Wind	1.17	1.38	2.11	2.11	2.13	2.19	2.41	2.0%
Total marketed renewable energy	**8.62**	**8.39**	**10.58**	**11.12**	**11.50**	**11.89**	**12.54**	**1.4%**
Sources of ethanol								
from corn and other starch	1.18	1.12	1.11	1.12	1.12	1.12	1.13	0.0%
from cellulose	0.00	0.00	0.01	0.02	0.02	0.02	0.02	- -
Net imports	-0.09	-0.02	0.07	0.08	0.08	0.08	0.11	- -
Total	**1.09**	**1.10**	**1.19**	**1.22**	**1.22**	**1.22**	**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 2012-2040 (percent)
	2011	2012	2020	2025	2030	2035	2040	
Nonmarketed renewable energy[8]								
Selected consumption								
Residential	**0.03**	**0.04**	**0.14**	**0.16**	**0.19**	**0.23**	**0.27**	**6.9%**
Solar hot water heating	0.00	0.01	0.01	0.01	0.01	0.01	0.01	2.4%
Geothermal heat pumps	0.01	0.01	0.02	0.02	0.02	0.02	0.03	3.2%
Solar photovoltaic	0.02	0.02	0.10	0.12	0.14	0.18	0.22	8.3%
Wind	0.00	0.00	0.01	0.01	0.01	0.01	0.01	9.1%
Commercial	**0.11**	**0.13**	**0.18**	**0.21**	**0.24**	**0.29**	**0.35**	**3.7%**
Solar thermal	0.08	0.08	0.09	0.09	0.09	0.10	0.11	1.0%
Solar photovoltaic	0.03	0.05	0.10	0.12	0.15	0.19	0.24	5.9%
Wind	0.00	0.00	0.00	0.00	0.00	0.01	0.01	8.3%

[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. 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 is determined by using the fossil fuel equivalent of 9,716 Btu per kilowatthour.
[2]Includes 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.
[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 2012 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 2011 and 2012 are model results and may differ from official EIA data reports.
Sources: 2011 and 2012 ethanol: U.S. Energy Information Administration (EIA), *Monthly Energy Review*, DOE/EIA-0035(2013/09) (Washington, DC, September 2013). 2011 and 2012 electric power sector: EIA, Form EIA-860, "Annual Electric Generator Report" (preliminary). Other 2011 and 2012 values: EIA, Office of Energy Analysis. **Projections:** EIA, AEO2014 National Energy Modeling System run REF2014.D102413A.

Table A18. Energy-related carbon dioxide emissions by sector and source
(million metric tons, unless otherwise noted)

Sector and source	Reference case							Annual growth 2012-2040 (percent)
	2011	2012	2020	2025	2030	2035	2040	
Residential								
Petroleum	72	69	60	55	51	48	45	-1.6%
Natural gas	255	226	242	239	235	229	223	0.0%
Electricity[1]	824	760	751	770	785	800	814	0.2%
Total residential	**1,150**	**1,056**	**1,054**	**1,064**	**1,071**	**1,077**	**1,082**	**0.1%**
Commercial								
Petroleum	47	45	49	48	48	48	48	0.2%
Natural gas	171	157	172	174	178	185	194	0.7%
Coal	6	4	4	4	4	4	4	0.0%
Electricity[1]	769	732	728	760	781	801	823	0.4%
Total commercial	**992**	**939**	**952**	**987**	**1,011**	**1,038**	**1,069**	**0.5%**
Industrial[2]								
Petroleum	347	350	395	402	405	404	406	0.5%
Natural gas[3]	432	449	512	540	556	567	578	0.9%
Coal	148	139	152	152	147	140	139	0.0%
Electricity[1]	574	543	628	658	654	638	625	0.5%
Total industrial	**1,501**	**1,480**	**1,688**	**1,752**	**1,761**	**1,750**	**1,748**	**0.6%**
Transportation								
Petroleum[4]	1,812	1,771	1,734	1,669	1,618	1,603	1,600	-0.4%
Natural gas[5]	39	41	44	48	58	70	91	2.9%
Electricity[1]	4	4	5	6	7	8	9	3.1%
Total transportation	**1,854**	**1,815**	**1,782**	**1,723**	**1,683**	**1,681**	**1,700**	**-0.2%**
Electric power[6]								
Petroleum	27	19	13	14	14	14	14	-1.0%
Natural gas	409	494	478	514	545	578	608	0.7%
Coal	1,723	1,514	1,609	1,654	1,656	1,643	1,637	0.3%
Other[7]	12	12	12	12	12	12	12	0.0%
Total electric power	**2,171**	**2,039**	**2,112**	**2,194**	**2,227**	**2,247**	**2,271**	**0.4%**
Total by fuel								
Petroleum[4]	2,304	2,254	2,252	2,188	2,136	2,117	2,113	-0.2%
Natural gas	1,306	1,366	1,447	1,516	1,572	1,629	1,694	0.8%
Coal	1,876	1,657	1,766	1,810	1,807	1,788	1,780	0.3%
Other[7]	12	12	12	12	12	12	12	0.0%
Total	**5,498**	**5,290**	**5,476**	**5,526**	**5,527**	**5,546**	**5,599**	**0.2%**
Carbon dioxide emissions (tons per person)	**17.6**	**16.8**	**16.4**	**15.9**	**15.4**	**15.0**	**14.7**	**-0.5%**

[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 2012, international bunker fuels accounted for 90 to 126 million metric tons annually.
[5]Includes pipeline fuel natural gas and natural gas used as fuel in motor vehicles, trains, and ships.
[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 2011 and 2012 are model results and may differ from official EIA data reports.
Sources: 2011 and 2012 emissions and emission factors: U.S. Energy Information Administration (EIA), *Monthly Energy Review*, DOE/EIA-0384(2013/09) (Washington, DC, September 2013). 2011 emissions: EIA, *Monthly Energy Review*, DOE/EIA-0035(2011/10) (Washington, DC, October 2011). 2012 emissions and emission factors: EIA, *Monthly Energy Review*, DOE/EIA-0035(2012/08) (Washington, DC, August 2012). **Projections:** EIA, AEO2014 National Energy Modeling System run REF2014.D102413A.

Table A19. Energy-related carbon dioxide emissions by end use
(million metric tons)

Sector and end use	Reference case							Annual growth 2012-2040 (percent)
	2011	2012	2020	2025	2030	2035	2040	
Residential								
Space heating	285.2	235.7	254.0	245.4	236.2	226.7	217.3	-0.3%
Space cooling	141.5	139.7	139.1	151.3	162.1	172.5	181.4	0.9%
Water heating	146.6	145.2	143.4	144.9	144.1	140.7	137.0	-0.2%
Refrigeration	64.1	61.5	58.3	58.0	57.9	58.7	59.6	-0.1%
Cooking	30.8	30.1	31.0	31.9	32.7	33.5	34.1	0.4%
Clothes dryers	36.3	35.1	35.7	36.9	37.8	38.8	39.5	0.4%
Freezers	13.5	13.0	12.4	12.1	11.8	11.5	11.3	-0.5%
Lighting	108.3	103.0	67.7	60.1	52.8	44.2	39.8	-3.3%
Clothes washers[1]	5.4	5.1	4.0	3.4	3.2	3.2	3.2	-1.6%
Dishwashers[1]	16.9	16.2	15.2	15.0	15.7	16.5	17.2	0.2%
Televisions and related equipment[2]	56.7	54.0	50.8	51.5	52.8	54.9	55.9	0.1%
Computers and related equipment[3]	21.7	20.2	15.2	12.9	10.8	9.2	7.6	-3.4%
Furnace fans and boiler circulation pumps	20.0	15.3	17.9	17.9	17.8	17.5	17.0	0.4%
Other uses[4]	203.6	181.4	209.0	222.8	235.9	248.7	260.7	1.3%
Discrepancy[5]	-0.4	0.3	0.0	0.0	0.0	0.0	0.0	- -
Total residential	**1,150.4**	**1,055.9**	**1,053.7**	**1,064.2**	**1,071.5**	**1,076.6**	**1,081.7**	**0.1%**
Commercial								
Space heating[6]	131.4	115.4	125.8	122.9	118.7	114.6	110.2	-0.2%
Space cooling[6]	95.2	92.1	81.5	82.9	82.6	82.9	83.4	-0.4%
Water heating[6]	42.7	42.8	43.5	44.4	44.5	44.3	44.1	0.1%
Ventilation	86.7	83.8	85.1	87.9	88.3	88.5	88.8	0.2%
Cooking	14.1	14.2	14.5	14.9	15.3	15.6	15.9	0.4%
Lighting	162.2	151.8	136.3	135.4	131.3	125.3	121.2	-0.8%
Refrigeration	65.7	62.0	57.0	57.1	57.2	57.8	58.4	-0.2%
Office equipment (PC)	21.3	18.7	10.5	7.8	5.7	4.3	3.4	-6.0%
Office equipment (non-PC)	37.8	35.3	37.3	41.7	46.5	51.1	55.1	1.6%
Other uses[7]	335.4	322.6	360.6	392.2	420.7	453.4	488.2	1.5%
Total commercial	**992.3**	**938.6**	**952.2**	**987.2**	**1,010.8**	**1,037.9**	**1,068.7**	**0.5%**
Industrial[8]								
Manufacturing								
Refining								-0.2%
Food products	252.4	257.5	254.7	248.9	245.1	244.6	246.7	0.9%
Paper products	96.4	96.8	106.4	111.9	116.2	119.8	123.7	0.1%
Bulk chemicals	74.5	71.0	69.9	70.9	70.9	71.6	73.2	0.5%
Glass	254.8	247.7	295.6	313.5	310.4	295.8	282.2	0.2%
Cement and lime	15.5	15.4	16.1	16.3	17.1	16.7	16.1	1.8%
Iron and steel	29.0	29.1	42.2	43.6	45.0	45.7	47.3	-0.4%
Aluminum	126.9	124.8	136.5	142.4	133.7	120.9	110.4	-0.8%
Fabricated metal products	45.3	45.6	50.3	54.2	49.7	41.2	36.3	0.4%
Machinery	37.8	38.2	42.3	44.3	43.8	43.0	42.2	0.9%
Computers and electronics	21.4	21.8	25.0	27.1	28.2	28.2	28.2	1.3%
Transportation equipment	46.3	46.4	50.5	57.4	61.7	64.6	65.8	1.4%
Electrical equipment	41.7	44.3	50.5	53.2	58.2	62.1	65.0	1.1%
Wood products	8.3	8.2	9.1	9.9	10.5	10.9	11.1	0.5%
Plastics	15.6	15.4	20.7	20.3	19.4	18.2	17.5	0.4%
Balance of manufacturing	39.7	38.7	42.4	44.3	44.6	44.0	43.6	0.9%
Total manufacturing	159.7	154.0	166.2	174.3	179.4	185.8	195.5	**0.4%**
Nonmanufacturing	**1,265.2**	**1,254.9**	**1,378.4**	**1,432.6**	**1,433.9**	**1,413.3**	**1,404.8**	
Agriculture								0.6%
Construction	71.0	65.5	75.7	76.7	77.3	77.4	77.7	1.5%
Mining	59.7	61.0	81.1	83.9	86.6	88.7	91.7	0.0%
Total nonmanufacturing	100.5	101.0	113.3	111.5	107.4	103.9	100.1	**0.6%**
Discrepancy[5]	**231.1**	**227.5**	**270.1**	**272.1**	**271.3**	**270.0**	**269.5**	- -
Total industrial	4.9	-2.6	39.1	47.5	56.2	66.6	74.1	**0.6%**

Table A19. Energy-related carbon dioxide emissions by end use (continued)
(million metric tons)

Sector and end use	Reference case							Annual growth 2012-2040 (percent)
	2011	2012	2020	2025	2030	2035	2040	
Transportation								
Light-duty vehicles	1,037.7	1,030.7	934.9	845.5	780.7	753.9	743.8	-1.2%
Commercial light trucks[9]	35.9	35.6	36.1	34.9	34.1	34.4	35.6	0.0%
Bus transportation	16.8	16.1	16.0	16.1	16.0	15.9	15.8	-0.1%
Freight trucks	369.7	357.7	415.3	438.4	457.1	478.1	502.2	1.2%
Rail, passenger	5.5	5.4	5.6	5.9	6.1	6.2	6.5	0.7%
Rail, freight	36.9	34.7	31.7	32.0	30.5	28.8	27.2	-0.9%
Shipping, domestic	8.1	7.0	6.8	6.3	5.9	5.6	5.5	-0.9%
Shipping, international	60.0	45.3	46.0	46.6	47.1	47.5	47.9	0.2%
Recreational boats	16.1	16.1	17.0	17.7	18.2	18.6	18.8	0.6%
Air	174.4	175.2	184.1	188.1	190.3	190.8	191.4	0.3%
Military use	52.5	50.1	45.4	46.1	48.6	51.4	54.4	0.3%
Lubricants	5.0	4.4	4.5	4.5	4.5	4.5	4.6	0.1%
Pipeline fuel	37.1	38.8	39.3	40.6	43.5	44.3	44.9	0.5%
Discrepancy[5]	-1.4	-1.7	-0.4	0.1	0.6	1.2	1.7	- -
Total transportation	**1,854.1**	**1,815.4**	**1,782.4**	**1,722.6**	**1,683.2**	**1,681.3**	**1,700.4**	**-0.2%**
Biogenic energy combustion[10]								
Biomass	200.6	188.7	242.7	277.4	297.0	311.1	326.0	2.0%
Electric power sector	17.3	13.7	44.0	65.6	74.5	77.9	80.3	6.5%
Other sectors	183.3	175.0	198.7	211.8	222.5	233.2	245.7	1.2%
Biogenic waste	17.6	19.1	22.5	21.1	21.1	21.9	22.8	0.6%
Biofuels heat and coproducts	43.3	48.6	71.6	73.8	73.9	73.8	73.8	1.5%
Ethanol	74.8	75.5	81.6	83.3	83.3	83.2	86.1	0.5%
Biodiesel	8.5	8.4	12.6	12.5	12.5	12.7	12.7	1.5%
Liquids from biomass	0.0	0.0	1.0	1.0	1.0	1.0	1.0	- -
Renewable diesel and gasoline	0.0	0.0	0.9	0.9	0.9	0.9	0.9	- -
Total	**344.8**	**340.3**	**432.9**	**470.1**	**489.7**	**504.6**	**523.3**	**1.5%**

[1]Does not include water heating portion of load.
[2]Includes televisions, set-top boxes, home theater systems, DVD players, and video game consoles.
[3]Includes desktop and laptop computers, monitors, and networking equipment.
[4]Includes small electric devices, heating elements, outdoor grills, exterior lights, pool heaters, spa heaters, backup electricity generators, and motors not listed above. Electric vehicles are included in the transportation sector.
[5]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.
[6]Includes emissions related to fuel consumption for district services.
[7]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, propane, coal, motor gasoline, kerosene, and marketed renewable fuels (biomass).
[8]Includes combined heat and power plants that have a non-regulatory status, and small on-site generating systems.
[9]Commercial trucks 8,501 to 10,000 pounds gross vehicle weight rating.
[10]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 2011 and 2012 are model results and may differ from official EIA data reports.
Sources: 2011 and 2012 emissions and emission factors: U.S. Energy Information Administration (EIA), *Monthly Energy Review*, DOE/EIA-0035(2013/09) (Washington, DC, September 2013). **Projections:** EIA, AEO2014 National Energy Modeling System run REF2014.D102413A.

Table A20. Macroeconomic indicators
(billion 2005 chain-weighted dollars, unless otherwise noted)

Indicators	Reference case 2011	2012	2020	2025	2030	2035	2040	Annual growth 2012-2040 (percent)
Real gross domestic product	**13,299**	**13,593**	**16,753**	**18,769**	**21,139**	**23,751**	**26,670**	**2.4%**
Components of real gross domestic product								
Real consumption	9,429	9,603	11,592	12,773	14,220	15,828	17,635	2.2%
Real investment	1,744	1,914	2,876	3,269	3,740	4,274	4,925	3.4%
Real government spending	2,524	2,481	2,443	2,495	2,623	2,754	2,917	0.6%
Real exports	1,777	1,837	2,863	3,857	5,056	6,516	8,186	5.5%
Real imports	2,185	2,238	2,925	3,453	4,213	5,167	6,328	3.8%
Energy intensity (thousand Btu per 2005 dollar of GDP)								
Delivered energy	5.29	5.08	4.40	3.97	3.54	3.18	2.88	-2.0%
Total energy	7.30	6.99	6.01	5.46	4.89	4.39	3.99	-2.0%
Price indices								
GDP chain-type price index (2005=1.000)	1.134	1.154	1.307	1.421	1.553	1.719	1.913	1.8%
Consumer price index (1982-4=1.00)								
All-urban	2.25	2.30	2.63	2.90	3.20	3.59	4.05	2.1%
Energy commodities and services	2.44	2.46	2.55	2.91	3.33	3.86	4.56	2.2%
Wholesale price index (1982=1.00)								
All commodities	2.01	2.02	2.22	2.40	2.62	2.89	3.21	1.7%
Fuel and power	2.16	2.12	2.42	2.82	3.30	3.92	4.73	2.9%
Metals and metal products	2.26	2.20	2.43	2.56	2.77	2.99	3.22	1.4%
Industrial commodities excluding energy	1.93	1.94	2.14	2.26	2.41	2.59	2.78	1.3%
Interest rates (percent, nominal)								
Federal funds rate	0.10	0.14	3.85	3.99	4.14	4.20	4.22	- -
10-year treasury note	2.79	1.80	4.14	4.24	4.36	4.45	4.52	- -
AA utility bond rate	4.78	3.83	6.60	6.74	6.88	7.05	7.22	- -
Value of shipments (billion 2005 dollars)								
Non-industrial and service sectors	21,240	21,359	26,033	28,947	31,782	34,480	37,135	2.0%
Total industrial	5,926	6,147	7,960	8,778	9,537	10,241	10,994	2.1%
Agriculture, mining, and construction	1,556	1,623	2,226	2,311	2,389	2,457	2,551	1.6%
Manufacturing	4,370	4,525	5,735	6,467	7,148	7,784	8,443	2.3%
Energy-intensive	1,599	1,616	1,931	2,081	2,171	2,238	2,303	1.3%
Non-energy-intensive	2,772	2,909	3,803	4,386	4,977	5,547	6,140	2.7%
Total shipments	**27,166**	**27,506**	**33,994**	**37,725**	**41,319**	**44,721**	**48,129**	**2.0%**
Population and employment (millions)								
Population, with armed forces overseas	312.3	314.6	334.5	347.0	359.0	370.2	380.5	0.7%
Population, aged 16 and over	247.0	249.2	266.7	277.2	287.6	297.9	307.3	0.8%
Population, over age 65	41.7	43.4	56.2	65.3	73.0	77.5	79.8	2.2%
Employment, nonfarm	131.5	133.7	148.4	152.2	158.6	163.7	169.2	0.8%
Employment, manufacturing	11.7	11.9	12.8	12.9	12.5	11.8	11.0	-0.3%
Key labor indicators								
Labor force (millions)	153.6	155.0	163.5	166.9	170.9	175.8	181.2	0.6%
Nonfarm labor productivity (2005=1.00)	1.10	1.11	1.25	1.39	1.53	1.68	1.85	1.8%
Unemployment rate (percent)	8.93	8.08	5.49	5.29	5.10	5.08	5.12	- -
Key indicators for energy demand								
Real disposable personal income	10,150	10,304	12,710	14,162	15,926	17,749	19,724	2.3%
Housing starts (millions)	0.66	0.84	1.75	1.72	1.71	1.67	1.66	2.5%
Commercial floorspace (billion square feet)	81.7	82.4	89.1	93.9	98.2	103.1	108.9	1.0%
Unit sales of light-duty vehicles (millions)	12.73	14.43	16.23	16.55	17.23	17.45	17.93	0.8%

GDP = Gross domestic product.
Btu = British thermal unit.
- - = Not applicable.
Sources: 2011 and 2012: IHS Global Insight, Global Insight Industry and Employment models, May 2013. **Projections:** U.S. Energy Information Administration, AEO2014 National Energy Modeling System run REF2014.D102413A.

Table A21. International petroleum and other liquids supply, disposition, and prices
(million barrels per day, unless otherwise noted)

Supply, disposition, and prices	Reference case							Annual growth 2012-2040 (percent)
	2011	2012	2020	2025	2030	2035	2040	
Crude oil spot prices								
(2012 dollars per barrel)								
Brent	113.24	111.65	96.57	108.99	118.99	129.77	141.46	0.8%
West Texas Intermediate	96.55	94.12	94.57	106.99	116.99	127.77	139.46	1.4%
(nominal dollars per barrel)								
Brent	111.26	111.65	109.37	134.25	160.19	193.27	234.53	2.7%
West Texas Intermediate	94.86	94.12	107.11	131.78	157.49	190.30	231.22	3.3%
Petroleum and other liquids consumption[1]								
OECD								
United States (50 states)	18.65	18.21	19.23	18.97	18.63	18.46	18.42	0.0%
United States territories	0.25	0.25	0.29	0.31	0.33	0.35	0.37	1.5%
Canada	2.25	2.26	2.24	2.17	2.18	2.22	2.30	0.1%
Mexico and Chile	2.45	2.51	2.71	2.85	3.08	3.33	3.63	1.3%
OECD Europe[2]	14.81	14.21	13.85	13.83	13.94	14.12	14.32	0.0%
Japan	4.51	4.75	4.50	4.38	4.29	4.19	4.05	-0.6%
South Korea	2.62	2.65	2.76	2.67	2.68	2.71	2.76	0.2%
Australia and New Zealand	1.24	1.28	1.23	1.19	1.21	1.25	1.30	0.0%
Total OECD consumption	**46.79**	**46.13**	**46.82**	**46.37**	**46.37**	**46.63**	**47.15**	**0.1%**
Non-OECD								
Russia	3.12	3.20	3.55	3.64	3.81	3.91	3.92	0.7%
Other Europe and Eurasia[3]	1.91	1.99	2.32	2.43	2.62	2.82	3.08	1.6%
China	9.94	10.36	13.91	15.70	17.04	18.72	20.48	2.5%
India	3.47	3.68	4.50	5.19	6.11	7.14	8.33	3.0%
Other Asia[4]	7.15	6.97	7.99	8.60	9.35	10.21	11.16	1.7%
Middle East	7.60	7.67	8.81	8.85	9.22	9.75	10.38	1.1%
Africa	3.40	3.47	3.70	3.84	4.03	4.28	4.58	1.0%
Brazil	2.74	2.83	3.12	3.10	3.32	3.52	3.85	1.1%
Other Central and South America	2.76	2.77	3.29	3.51	3.76	3.97	4.13	1.4%
Total non-OECD consumption	**42.10**	**42.94**	**51.19**	**54.84**	**59.24**	**64.32**	**69.90**	**1.8%**
Total consumption	**88.88**	**89.07**	**98.01**	**101.21**	**105.61**	**110.96**	**117.05**	**1.0%**
Petroleum and other liquids production								
OPEC[5]								
Middle East	25.50	25.84	28.28	29.62	32.35	35.77	38.85	1.5%
North Africa	2.37	3.36	3.19	3.20	3.43	3.75	3.96	0.6%
West Africa	4.39	4.40	4.99	5.13	5.26	5.39	5.52	0.8%
South America	2.99	2.99	3.10	3.03	3.01	3.10	3.31	0.4%
Total OPEC production	**35.25**	**36.59**	**39.57**	**40.97**	**44.04**	**48.00**	**51.64**	**1.2%**
Non-OPEC								
OECD								
United States (50 states)	10.11	10.84	14.25	13.86	13.23	12.86	12.42	0.5%
Canada	3.71	4.00	5.10	5.61	5.92	6.12	6.21	1.6%
Mexico and Chile	2.99	2.97	2.13	1.97	2.11	2.18	2.27	-1.0%
OECD Europe[2]	4.20	3.93	3.26	2.94	2.78	2.98	3.63	-0.3%
Japan and South Korea	0.18	0.18	0.16	0.17	0.18	0.18	0.19	0.2%
Australia and New Zealand	0.58	0.57	0.54	0.53	0.56	0.80	0.92	1.7%
Total OECD production	**21.77**	**22.48**	**25.44**	**25.07**	**24.78**	**25.11**	**25.64**	**0.5%**
Non-OECD								
Russia	10.24	10.40	10.74	10.93	11.44	12.01	11.68	0.4%
Other Europe and Eurasia[3]	3.26	3.19	3.73	4.35	4.44	4.62	5.44	1.9%
China	4.32	4.37	4.91	5.35	5.50	5.59	5.62	0.9%
Other Asia[4]	3.81	3.82	3.63	3.42	3.20	3.03	3.31	-0.5%
Middle East	1.51	1.31	0.98	0.86	0.77	0.67	0.71	-2.2%
Africa	2.67	2.34	2.61	2.63	2.57	2.52	2.91	0.8%
Brazil	2.53	2.49	4.00	5.14	6.36	6.81	7.03	3.8%
Other Central and South America	2.16	2.16	2.38	2.42	2.44	2.56	3.06	1.3%
Total non-OECD production	**30.51**	**30.08**	**32.98**	**35.11**	**36.73**	**37.83**	**39.75**	**1.0%**
Total petroleum and other liquids production	**87.53**	**89.15**	**97.99**	**101.15**	**105.55**	**110.94**	**117.03**	**1.0%**
OPEC market share (percent)	40.3	41.0	40.4	40.5	41.7	43.3	44.1	- -

Table A21. International petroleum and other liquids supply, disposition, and prices (continued)
(million barrels per day, unless otherwise noted)

Supply, disposition, and prices	Reference case							Annual growth 2012-2040 (percent)
	2011	2012	2020	2025	2030	2035	2040	
Selected world production subtotals:								
Petroleum								
Crude oil and equivalents[6]	74.37	75.78	82.35	84.40	87.58	91.09	96.56	0.9%
Tight oil	1.36	2.40	5.81	6.43	6.88	7.17	7.28	4.0%
Bitumen[7]	1.74	1.94	3.00	3.52	3.95	4.21	4.26	2.8%
Refinery processing gain[8]	2.37	2.37	2.26	2.33	2.52	2.71	2.86	0.7%
Liquids from renewable sources[9]	1.31	1.34	1.68	1.89	2.09	2.28	2.48	2.2%
Liquids from coal[10]	0.18	0.19	0.40	0.65	0.91	1.12	1.12	6.6%
Liquids from natural gas	8.73	9.21	10.78	11.61	12.19	12.88	13.29	1.3%
Natural gas plant liquids	8.61	9.05	10.46	11.26	11.84	12.53	12.93	1.3%
Gas-to-liquids[11]	0.12	0.16	0.31	0.35	0.35	0.35	0.35	2.9%
Liquids from kerogen[12]	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.6%
Petroleum production[13]								
OPEC[5]								
Middle East	25.44	25.74	28.07	29.38	32.10	35.52	38.61	1.5%
North Africa	2.37	3.36	3.19	3.20	3.43	3.75	3.96	0.6%
West Africa	4.39	4.40	4.96	5.09	5.22	5.35	5.49	0.8%
South America	2.99	2.99	3.10	3.03	3.01	3.10	3.31	0.4%
Total OPEC production	**35.20**	**36.50**	**39.33**	**40.70**	**43.77**	**47.73**	**51.37**	**1.2%**
Non-OPEC								
OECD								
United States (50 states)	9.25	10.00	13.28	12.87	12.24	11.87	11.42	0.5%
Canada	3.69	3.97	5.08	5.58	5.88	6.08	6.17	1.6%
Mexico and Chile	2.99	2.97	2.13	1.97	2.11	2.18	2.27	-1.0%
OECD Europe[2]	3.98	3.71	3.03	2.70	2.53	2.71	3.35	-0.4%
Japan and South Korea	0.17	0.17	0.15	0.16	0.17	0.18	0.18	0.1%
Australia and New Zealand	0.58	0.56	0.53	0.52	0.55	0.79	0.91	1.7%
Total OECD production	**20.65**	**21.39**	**24.21**	**23.80**	**23.49**	**23.80**	**24.30**	**0.5%**
Non-OECD								
Russia	10.24	10.40	10.74	10.93	11.44	12.01	11.68	0.4%
Other Europe and Eurasia[3]	3.26	3.19	3.73	4.34	4.44	4.62	5.43	1.9%
China	4.28	4.32	4.77	4.98	4.82	4.69	4.72	0.3%
Other Asia[4]	3.74	3.75	3.51	3.22	2.99	2.82	3.10	-0.7%
Middle East	1.51	1.31	0.98	0.86	0.77	0.67	0.71	-2.2%
Africa	2.45	2.13	2.28	2.29	2.22	2.17	2.55	0.6%
Brazil	2.25	2.20	3.50	4.55	5.65	5.96	6.00	3.6%
Other Central and South America	2.08	2.06	2.30	2.34	2.36	2.47	2.97	1.3%
Total non-OECD production	**29.81**	**29.35**	**31.81**	**33.51**	**34.69**	**35.40**	**37.15**	**0.8%**
Total petroleum production[13]	**85.66**	**87.24**	**95.34**	**98.01**	**101.95**	**106.94**	**112.82**	**0.9%**
OPEC market share (percent)	41.1	41.8	41.2	41.5	42.9	44.6	45.5	- -

[1]Estimated consumption. Includes both OPEC and non-OPEC consumers in the regional breakdown.
[2]OECD Europe - 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, India (for production), 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 the Petroleum Exporting Countries - Algeria, Angola, Ecuador, Iran, Iraq, Kuwait, Libya, Nigeria, Qatar, Saudi Arabia, the United Arab Emirates, and Venezuela.
[6]Includes crude oil, lease condensate, tight oil (shale oil), extra-heavy oil, and bitumen (oil sands).
[7]Includes diluted and upgraded/synthetic bitumen (syncrude).
[8]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.
[9]Includes liquids produced from energy crops.
[10]Includes liquids converted from coal via the Fischer-Tropsch coal-to-liquids process.
[11]Includes liquids converted from natural gas via the Fischer-Tropsch gas-to-liquids process.
[12]Includes liquids produced from kerogen (oil shale, not to be confused with tight oil (shale oil)).
[13]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.
OECD = Organization for Economic Cooperation and Development.
- - = Not applicable.
Note: Ethanol is represented in motor gasoline equivalent barrels. Totals may not equal sum of components due to independent rounding. Data for 2011 and 2012 are model results and may differ from official EIA data reports.
Sources: 2011 and 2012 Brent and West Texas Intermediate crude oil spot prices: Thomson Reuters. 2011 quantities derived from: Energy Information Administration (EIA), International Energy Statistics database as of September 2013. **2012 quantities and projections:** EIA, AEO2014 National Energy Modeling System run REF2014.D102413A 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	2012	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
Production										
Crude oil and lease condensate	13.87	20.31	20.36	20.39	17.40	17.71	17.82	16.04	16.00	16.40
Natural gas plant liquids	3.21	3.53	3.54	3.55	3.92	3.98	4.09	3.92	3.99	4.05
Dry natural gas	24.59	29.02	29.73	30.59	33.37	35.19	36.94	36.09	38.37	40.33
Coal[1]	20.60	21.18	21.70	22.24	21.67	22.61	23.28	21.67	22.61	23.50
Nuclear / uranium[2]	8.05	8.15	8.15	8.15	8.15	8.18	8.30	8.15	8.49	9.65
Hydropower	2.67	2.84	2.81	2.83	2.84	2.87	2.90	2.86	2.90	2.92
Biomass[3]	3.78	4.52	4.66	4.77	5.02	5.29	5.48	5.24	5.61	6.02
Other renewable energy[4]	1.97	3.09	3.01	3.04	3.25	3.23	3.71	3.42	3.89	5.13
Other[5]	0.41	0.24	0.24	0.23	0.24	0.24	0.23	0.24	0.24	0.23
Total	**79.15**	**92.88**	**94.19**	**95.80**	**95.87**	**99.30**	**102.74**	**97.63**	**102.09**	**108.23**
Imports										
Crude oil	18.57	12.31	13.15	14.08	12.98	15.00	16.49	14.11	17.43	19.26
Petroleum and other liquids[6]	4.26	4.20	4.21	4.25	4.06	4.08	4.12	3.92	3.93	4.45
Natural gas[7]	3.21	2.38	2.39	2.46	1.87	2.01	2.12	2.21	2.28	2.41
Other imports[8]	0.36	0.14	0.17	0.16	0.11	0.12	0.12	0.09	0.10	0.19
Total	**26.40**	**19.03**	**19.92**	**20.95**	**19.02**	**21.22**	**22.84**	**20.34**	**23.73**	**26.30**
Exports										
Petroleum and other liquids[9]	6.29	6.32	6.30	6.29	6.85	6.91	7.00	7.63	7.70	7.75
Natural gas[10]	1.63	4.49	4.30	4.28	6.96	6.96	6.93	8.26	8.09	7.90
Coal	3.22	3.13	3.13	3.11	3.53	3.55	3.57	3.77	3.79	3.73
Total	**11.14**	**13.95**	**13.73**	**13.68**	**17.35**	**17.42**	**17.50**	**19.66**	**19.58**	**19.38**
Discrepancy[11]	**-0.61**	**-0.35**	**-0.35**	**-0.30**	**-0.17**	**-0.17**	**-0.15**	**-0.03**	**-0.07**	**-0.07**
Consumption										
Petroleum and other liquids[12]	35.87	35.93	36.86	37.82	33.28	35.65	37.27	32.04	35.35	38.13
Natural gas	26.20	26.73	27.65	28.60	28.08	30.03	31.92	29.78	32.32	34.62
Coal[13]	17.34	18.01	18.56	19.11	18.08	19.01	19.66	17.83	18.75	19.75
Nuclear / uranium[2]	8.05	8.15	8.15	8.15	8.15	8.18	8.30	8.15	8.49	9.65
Hydropower	2.67	2.84	2.81	2.83	2.84	2.87	2.90	2.86	2.90	2.92
Biomass[14]	2.53	3.22	3.35	3.46	3.69	3.95	4.13	3.92	4.26	4.63
Other renewable energy[4]	1.97	3.09	3.01	3.04	3.25	3.23	3.71	3.42	3.89	5.13
Other[15]	0.39	0.34	0.34	0.34	0.33	0.35	0.35	0.34	0.35	0.38
Total	**95.02**	**98.31**	**100.73**	**103.36**	**97.71**	**103.27**	**108.23**	**98.34**	**106.31**	**115.22**
Prices (2012 dollars per unit)										
Crude oil spot prices (dollars per barrel)										
Brent	111.65	95.51	96.57	97.79	116.23	118.99	121.23	136.52	141.46	145.21
West Texas Intermediate	94.12	93.53	94.57	95.77	114.28	116.99	119.19	134.59	139.46	143.15
Natural gas at Henry Hub (dollars per million Btu)	2.75	4.51	4.38	4.59	5.65	6.03	6.39	7.19	7.65	8.15
Coal (dollars per ton) at the minemouth[16]	39.94	46.31	46.52	46.68	52.85	53.15	53.94	58.57	59.16	60.20
Coal (dollars per million Btu) at the minemouth[16]	1.98	2.32	2.33	2.34	2.66	2.67	2.71	2.94	2.96	3.02
Average end-use[17]	2.60	2.83	2.85	2.89	3.13	3.17	3.23	3.38	3.43	3.54
Average electricity (cents per kilowatthour)	9.8	10.1	10.1	10.1	10.3	10.4	10.6	10.8	11.1	11.6

Table B1. Total energy supply, disposition, and price summary (continued)
(quadrillion Btu per year, unless otherwise noted)

Supply, disposition, and prices	2012	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
Prices (nominal dollars per unit)										
Crude oil spot prices (dollars per barrel)										
Brent	111.65	114.20	109.37	108.50	195.53	160.19	154.87	335.90	234.53	222.72
West Texas Intermediate	94.12	111.84	107.11	106.25	192.24	157.49	152.27	331.15	231.22	219.57
Natural gas at Henry Hub (dollars per million Btu)	2.75	5.40	4.96	5.10	9.50	8.12	8.16	17.69	12.69	12.49
Coal (dollars per ton) at the minemouth[16]	39.94	55.37	52.69	51.79	88.91	71.55	68.91	144.11	98.08	92.34
Coal (dollars per million Btu) at the minemouth[16]	1.98	2.77	2.63	2.59	4.47	3.59	3.46	7.23	4.91	4.63
Average end-use[17]	2.60	3.38	3.23	3.21	5.27	4.27	4.13	8.31	5.68	5.43
Average electricity (cents per kilowatthour)	9.8	12.1	11.5	11.2	17.4	14.0	13.6	26.6	18.5	17.7

[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]Estimated consumption. 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 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 2012 are model results and may differ from official EIA data reports.
Sources: 2012 natural gas supply values: U.S. Energy Information Administration (EIA), *Natural Gas Monthly*, DOE/EIA-0130(2013/06) (Washington, DC, June 2013). 2012 coal minemouth and delivered coal prices: EIA, *Annual Coal Report 2012*, DOE/EIA-0584(2012) (Washington, DC, December 2013). 2012 petroleum supply values: EIA, *Petroleum Supply Annual 2012*, DOE/EIA-0340(2012)/1 (Washington, DC, September 2013). 2012 crude oil spot prices and natural gas spot price at Henry Hub: Thomson Reuters. Other 2012 coal values: *Quarterly Coal Report, October-December 2012*, DOE/EIA-0121(2012/4Q) (Washington, DC, March 2013). Other 2012 values: EIA, *Monthly Energy Review*, DOE/EIA-0035(2013/09) (Washington, DC, September 2013). **Projections:** EIA, AEO2014 National Energy Modeling System runs LOWMACRO.D112913A, REF2014.D102413A, and HIGHMACRO.D112913A.

Table B2. Energy consumption by sector and source

(quadrillion Btu per year, unless otherwise noted)

Sector and source	2012	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	0.51	0.42	0.42	0.43	0.37	0.38	0.40	0.33	0.35	0.38
Kerosene	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Distillate fuel oil	0.51	0.46	0.46	0.46	0.37	0.37	0.37	0.31	0.31	0.31
Petroleum and other liquids subtotal	1.02	0.88	0.89	0.89	0.74	0.75	0.77	0.64	0.66	0.69
Natural gas	4.26	4.50	4.56	4.61	4.25	4.43	4.64	3.91	4.21	4.55
Renewable energy[1]	0.45	0.45	0.46	0.47	0.43	0.44	0.45	0.40	0.42	0.44
Electricity	4.69	4.73	4.84	4.99	4.86	5.21	5.61	5.07	5.65	6.31
Delivered energy	**10.42**	**10.56**	**10.74**	**10.96**	**10.28**	**10.83**	**11.48**	**10.01**	**10.94**	**11.99**
Electricity related losses	9.68	9.43	9.64	9.85	9.53	10.00	10.61	9.60	10.55	11.71
Total	**20.10**	**19.99**	**20.38**	**20.81**	**19.81**	**20.83**	**22.09**	**19.62**	**21.48**	**23.70**
Commercial										
Propane	0.15	0.16	0.16	0.16	0.17	0.17	0.17	0.17	0.18	0.18
Motor gasoline[2]	0.05	0.04	0.04	0.04	0.05	0.05	0.05	0.05	0.05	0.06
Kerosene	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Distillate fuel oil	0.40	0.40	0.40	0.39	0.38	0.38	0.38	0.37	0.37	0.37
Residual fuel oil	0.04	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08
Petroleum and other liquids subtotal	0.63	0.68	0.68	0.68	0.67	0.67	0.68	0.67	0.68	0.68
Natural gas	2.96	3.22	3.23	3.22	3.33	3.35	3.37	3.60	3.65	3.70
Coal	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04
Renewable energy[3]	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13
Electricity	4.52	4.68	4.69	4.71	5.11	5.18	5.24	5.60	5.72	5.81
Delivered energy	**8.29**	**8.75**	**8.78**	**8.80**	**9.29**	**9.38**	**9.46**	**10.05**	**10.22**	**10.38**
Electricity related losses	9.32	9.34	9.34	9.31	10.01	9.94	9.91	10.61	10.66	10.80
Total	**17.61**	**18.09**	**18.12**	**18.11**	**19.30**	**19.32**	**19.38**	**20.66**	**20.88**	**21.17**
Industrial[4]										
Liquefied petroleum gases and other[5]	2.25	2.85	2.90	2.93	2.95	3.05	3.06	2.82	2.90	2.93
Motor gasoline[2]	0.26	0.29	0.30	0.31	0.28	0.30	0.31	0.27	0.29	0.31
Distillate fuel oil	1.20	1.32	1.40	1.48	1.28	1.41	1.52	1.28	1.42	1.56
Residual fuel oil	0.10	0.14	0.14	0.15	0.13	0.15	0.16	0.13	0.15	0.17
Petrochemical feedstocks	0.75	1.22	1.27	1.31	1.47	1.62	1.68	1.49	1.59	1.67
Other petroleum[6]	3.50	3.35	3.56	3.80	3.17	3.58	3.91	3.22	3.75	4.19
Petroleum and other liquids subtotal	8.06	9.17	9.56	9.97	9.29	10.10	10.64	9.21	10.10	10.82
Natural gas	7.29	7.99	8.26	8.50	8.10	8.71	9.20	8.11	8.87	9.73
Natural-gas-to-liquids heat and power	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Lease and plant fuel[7]	1.45	1.77	1.77	1.81	2.07	2.16	2.25	2.30	2.41	2.52
Natural gas subtotal	8.75	9.75	10.04	10.31	10.17	10.87	11.44	10.41	11.28	12.25
Metallurgical coal	0.55	0.54	0.58	0.65	0.49	0.55	0.65	0.41	0.47	0.64
Other industrial coal	0.93	0.95	0.99	1.04	0.92	1.00	1.10	0.92	1.01	1.20
Coal-to-liquids heat and power	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Net coal coke imports	0.00	0.00	0.00	0.01	-0.02	-0.03	-0.03	-0.04	-0.05	-0.06
Coal subtotal	1.48	1.50	1.57	1.70	1.38	1.52	1.72	1.28	1.44	1.78
Biofuels heat and coproducts	0.52	0.76	0.76	0.76	0.78	0.79	0.79	0.77	0.79	0.81
Renewable energy[8]	1.48	1.65	1.74	1.82	1.81	2.01	2.14	2.03	2.28	2.50
Electricity	3.35	3.83	4.04	4.32	3.91	4.33	4.76	3.87	4.34	5.01
Delivered energy	**23.63**	**26.67**	**27.71**	**28.87**	**27.35**	**29.62**	**31.49**	**27.58**	**30.22**	**33.17**
Electricity related losses	6.91	7.65	8.05	8.53	7.66	8.33	8.99	7.33	8.10	9.31
Total	**30.54**	**34.32**	**35.76**	**37.40**	**35.02**	**37.94**	**40.48**	**34.90**	**38.33**	**42.47**

Table B2. Energy consumption by sector and source (continued)
(quadrillion Btu per year, unless otherwise noted)

Sector and source	2012	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
Transportation										
Propane	0.05	0.05	0.05	0.05	0.05	0.06	0.06	0.06	0.07	0.08
Motor gasoline[2]	16.33	14.85	15.00	15.05	11.99	12.69	12.87	10.81	12.09	12.59
of which: E85[9]	0.01	0.19	0.19	0.18	0.54	0.46	0.42	0.47	0.33	0.34
Jet fuel[10]	3.00	3.06	3.08	3.10	3.15	3.20	3.25	3.19	3.28	3.37
Distillate fuel oil[11]	5.82	6.35	6.70	7.17	6.48	7.25	8.07	6.53	7.54	8.94
Residual fuel oil	0.58	0.58	0.58	0.58	0.59	0.59	0.59	0.60	0.60	0.61
Other petroleum[12]	0.15	0.14	0.15	0.15	0.14	0.15	0.15	0.14	0.15	0.15
Petroleum and other liquids subtotal	25.93	25.02	25.55	26.10	22.40	23.94	24.99	21.34	23.73	25.74
Pipeline fuel natural gas	0.73	0.72	0.74	0.76	0.78	0.82	0.86	0.80	0.85	0.89
Compressed / liquefied natural gas	0.04	0.08	0.08	0.08	0.28	0.28	0.30	0.86	0.86	1.05
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	0.04	0.06	0.06	0.06
Delivered energy	**26.72**	**25.85**	**26.40**	**26.98**	**23.50**	**25.08**	**26.20**	**23.05**	**25.50**	**27.75**
Electricity related losses	0.05	0.06	0.06	0.06	0.08	0.08	0.08	0.11	0.12	0.12
Total	**26.77**	**25.92**	**26.47**	**27.04**	**23.58**	**25.17**	**26.28**	**23.16**	**25.62**	**27.87**
Delivered energy consumption for all sectors										
Liquefied petroleum gases and other[5]	2.96	3.47	3.53	3.56	3.54	3.65	3.69	3.38	3.49	3.57
Motor gasoline[2]	16.64	15.18	15.34	15.40	12.31	13.04	13.22	11.13	12.44	12.96
of which: E85[9]	0.01	0.19	0.19	0.18	0.54	0.46	0.42	0.47	0.33	0.34
Jet fuel[10]	3.00	3.06	3.08	3.10	3.15	3.20	3.25	3.19	3.28	3.37
Kerosene	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Distillate fuel oil	7.93	8.52	8.95	9.51	8.51	9.41	10.34	8.49	9.63	11.17
Residual fuel oil	0.72	0.80	0.80	0.82	0.80	0.82	0.83	0.81	0.83	0.85
Petrochemical feedstocks	0.75	1.22	1.27	1.31	1.47	1.62	1.68	1.49	1.59	1.67
Other petroleum[13]	3.64	3.49	3.70	3.94	3.31	3.73	4.06	3.36	3.89	4.34
Petroleum and other liquids subtotal	35.64	35.76	36.68	37.64	33.10	35.47	37.09	31.86	35.17	37.93
Natural gas	14.56	15.78	16.14	16.42	15.97	16.77	17.51	16.47	17.59	19.04
Natural-gas-to-liquids heat and power	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Lease and plant fuel[7]	1.45	1.77	1.77	1.81	2.07	2.16	2.25	2.30	2.41	2.52
Pipeline natural gas	0.73	0.72	0.74	0.76	0.78	0.82	0.86	0.80	0.85	0.89
Natural gas subtotal	16.74	18.27	18.65	19.00	18.81	19.75	20.61	19.56	20.84	22.44
Metallurgical coal	0.55	0.54	0.58	0.65	0.49	0.55	0.65	0.41	0.47	0.64
Other coal	0.98	0.99	1.03	1.09	0.97	1.04	1.14	0.96	1.05	1.25
Coal-to-liquids heat and power	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Net coal coke imports	0.00	0.00	0.00	0.01	-0.02	-0.03	-0.03	-0.04	-0.05	-0.06
Coal subtotal	1.53	1.54	1.61	1.74	1.43	1.56	1.76	1.33	1.48	1.83
Biofuels heat and coproducts	0.52	0.76	0.76	0.76	0.78	0.79	0.79	0.77	0.79	0.81
Renewable energy[14]	2.06	2.24	2.33	2.41	2.38	2.58	2.72	2.56	2.83	3.07
Liquid hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Electricity	12.58	13.27	13.60	14.05	13.93	14.76	15.65	14.60	15.77	17.20
Delivered energy	**69.07**	**71.83**	**73.63**	**75.61**	**70.43**	**74.91**	**78.63**	**70.69**	**76.88**	**83.28**
Electricity related losses	25.95	26.48	27.10	27.75	27.28	28.35	29.60	27.65	29.43	31.93
Total	**95.02**	**98.31**	**100.73**	**103.36**	**97.71**	**103.27**	**108.23**	**98.34**	**106.31**	**115.22**
Electric power[15]										
Distillate fuel oil	0.05	0.09	0.09	0.09	0.09	0.09	0.09	0.08	0.09	0.09
Residual fuel oil	0.18	0.09	0.09	0.09	0.09	0.09	0.10	0.09	0.10	0.11
Petroleum and other liquids subtotal	0.23	0.17	0.18	0.18	0.17	0.18	0.19	0.18	0.19	0.20
Natural gas	9.46	8.47	9.00	9.60	9.27	10.28	11.31	10.21	11.48	12.18
Steam coal	15.82	16.48	16.95	17.36	16.65	17.44	17.90	16.51	17.27	17.93
Nuclear / uranium[16]	8.05	8.15	8.15	8.15	8.15	8.18	8.30	8.15	8.49	9.65
Renewable energy[17]	4.59	6.14	6.08	6.16	6.63	6.68	7.22	6.87	7.44	8.81
Non-biogenic municipal waste	0.23	0.23	0.23	0.23	0.23	0.23	0.23	0.23	0.23	0.23
Electricity imports	0.16	0.11	0.11	0.11	0.11	0.12	0.12	0.11	0.12	0.15
Total	**38.53**	**39.75**	**40.70**	**41.80**	**41.21**	**43.12**	**45.25**	**42.25**	**45.20**	**49.13**

Table B2. Energy consumption by sector and source (continued)
(quadrillion Btu per year, unless otherwise noted)

Sector and source	2012	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 and other[5]	2.96	3.47	3.53	3.56	3.54	3.65	3.69	3.38	3.49	3.57
Motor gasoline[2]	16.64	15.18	15.34	15.40	12.31	13.04	13.22	11.13	12.44	12.96
of which: E85[9]	0.01	0.19	0.19	0.18	0.54	0.46	0.42	0.47	0.33	0.34
Jet fuel[10]	3.00	3.06	3.08	3.10	3.15	3.20	3.25	3.19	3.28	3.37
Kerosene	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Distillate fuel oil	7.98	8.61	9.03	9.60	8.59	9.50	10.43	8.57	9.72	11.26
Residual fuel oil	0.90	0.89	0.89	0.91	0.89	0.91	0.93	0.90	0.93	0.96
Petrochemical feedstocks	0.75	1.22	1.27	1.31	1.47	1.62	1.68	1.49	1.59	1.67
Other petroleum[13]	3.64	3.49	3.70	3.94	3.31	3.73	4.06	3.36	3.89	4.34
Petroleum and other liquids subtotal	35.87	35.93	36.86	37.82	33.28	35.65	37.27	32.04	35.35	38.13
Natural gas	24.02	24.25	25.14	26.03	25.23	27.05	28.82	26.68	29.07	31.21
Natural-gas-to-liquids heat and power	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Lease and plant fuel[7]	1.45	1.77	1.77	1.81	2.07	2.16	2.25	2.30	2.41	2.52
Pipeline natural gas	0.73	0.72	0.74	0.76	0.78	0.82	0.86	0.80	0.85	0.89
Natural gas subtotal	26.20	26.73	27.65	28.60	28.08	30.03	31.92	29.78	32.32	34.62
Metallurgical coal	0.55	0.54	0.58	0.65	0.49	0.55	0.65	0.41	0.47	0.64
Other coal	16.79	17.47	17.98	18.45	17.62	18.49	19.04	17.47	18.32	19.18
Coal-to-liquids heat and power	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Net coal coke imports	0.00	0.00	0.00	0.01	-0.02	-0.03	-0.03	-0.04	-0.05	-0.06
Coal subtotal	17.34	18.01	18.56	19.11	18.08	19.01	19.66	17.83	18.75	19.75
Nuclear / uranium[16]	8.05	8.15	8.15	8.15	8.15	8.18	8.30	8.15	8.49	9.65
Biofuels heat and coproducts	0.52	0.76	0.76	0.76	0.78	0.79	0.79	0.77	0.79	0.81
Renewable energy[18]	6.65	8.38	8.40	8.58	9.00	9.26	9.95	9.43	10.27	11.88
Liquid hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Non-biogenic municipal waste	0.23	0.23	0.23	0.23	0.23	0.23	0.23	0.23	0.23	0.23
Electricity imports	0.16	0.11	0.11	0.11	0.11	0.12	0.12	0.11	0.12	0.15
Total	**95.02**	**98.31**	**100.73**	**103.36**	**97.71**	**103.27**	**108.23**	**98.34**	**106.31**	**115.22**
Energy use and related statistics										
Delivered energy use	69.07	71.83	73.63	75.61	70.43	74.91	78.63	70.69	76.88	83.28
Total energy use	95.02	98.31	100.73	103.36	97.71	103.27	108.23	98.34	106.31	115.22
Ethanol consumed in motor gasoline and E85	1.09	1.21	1.22	1.22	1.25	1.25	1.25	1.25	1.29	1.34
Population (millions)	314.58	332.91	334.47	336.27	354.64	359.03	364.05	372.79	380.53	389.40
Gross domestic product (billion 2005 dollars)	13,593	15,918	16,753	17,594	18,910	21,139	22,725	23,158	26,670	29,154
Carbon dioxide emissions (million metric tons)	5,290	5,327	5,476	5,633	5,195	5,527	5,778	5,170	5,599	5,972

[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 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 ethane, natural gasoline, and refinery olefins.
[6]Includes petroleum coke, asphalt, road oil, lubricants, still gas, and miscellaneous petroleum products.
[7]Represents natural gas used in well, field, and lease operations, in natural gas processing plant machinery, and for liquefaction in export facilities.
[8]Includes consumption of energy produced from hydroelectric, wood and wood waste, municipal waste, and other biomass sources. Excludes ethanol in motor gasoline.
[9]E85 refers to a blend of 85 percent ethanol (renewable) and 15 percent motor gasoline (nonrenewable). To address cold starting issues, the percentage of ethanol varies seasonally. The annual average ethanol content of 74 percent is used for this forecast.
[10]Includes only kerosene type.
[11]Diesel fuel for on- and off- road use.
[12]Includes aviation gasoline and lubricants.
[13]Includes aviation gasoline, petroleum coke, asphalt, road oil, lubricants, still gas, and miscellaneous petroleum products.
[14]Includes electricity generated for sale to the grid and for own use from renewable sources, and non-electric energy from renewable sources. Excludes ethanol and nonmarketed renewable energy consumption for geothermal heat pumps, buildings photovoltaic systems, and solar thermal water heaters.
[15]Includes consumption of energy by electricity-only and combined heat and power plants that have a regulatory status.
[16]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.
[17]Includes conventional hydroelectric, geothermal, wood and wood waste, biogenic municipal waste, other biomass, wind, photovoltaic, and solar thermal sources. Excludes net electricity imports.
[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: Includes estimated consumption for petroleum and other liquids. Totals may not equal sum of components due to independent rounding. Data for 2012 are model results and may differ from official EIA data reports.
Sources: 2012 consumption based on: U.S. Energy Information Administration (EIA), *Monthly Energy Review*, DOE/EIA-0035(2013/09) (Washington, DC, September 2013). 2012 population and gross domestic product: IHS Global Insight Industry and Employment models, May 2013. 2012 carbon dioxide emissions and emission factors: EIA, *Monthly Energy Review*, DOE/EIA-0035(2013/09) (Washington, DC, September 2013). **Projections:** EIA, AEO2014 National Energy Modeling System runs LOWMACRO.D112913A, REF2014.D102413A, and HIGHMACRO.D112913A.

Table B3. Energy prices by sector and source
(2012 dollars per million Btu, unless otherwise noted)

Sector and source	2012	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	24.12	23.76	23.79	24.21	25.45	25.75	26.02	27.09	27.64	27.99
Distillate fuel oil	27.30	24.26	24.67	25.12	27.69	28.60	29.24	31.27	32.64	33.97
Natural gas	10.46	11.58	11.59	12.22	12.92	13.50	14.06	14.90	15.98	17.10
Electricity	34.83	36.20	36.15	36.03	36.93	36.98	37.33	38.37	38.83	39.81
Commercial										
Propane	20.75	20.29	20.33	20.81	22.40	22.79	23.13	24.51	25.17	25.62
Distillate fuel oil	26.81	21.40	21.77	22.47	24.90	25.66	26.23	28.31	29.72	31.07
Residual fuel oil	22.84	14.19	14.40	14.52	17.39	17.92	18.26	20.36	20.99	21.89
Natural gas	8.11	9.50	9.49	9.96	10.72	11.19	11.62	12.26	13.08	13.94
Electricity	29.55	30.42	30.80	30.98	30.65	31.26	32.26	31.56	33.01	34.76
Industrial[1]										
Propane	21.09	20.60	20.64	21.14	22.86	23.27	23.64	25.10	25.84	26.32
Distillate fuel oil	27.41	21.86	22.22	22.77	25.46	26.11	26.65	28.77	29.92	31.25
Residual fuel oil	20.90	14.67	14.88	15.03	17.82	18.29	18.61	20.80	21.48	22.37
Natural gas[2]	3.77	5.84	5.79	6.08	6.57	6.99	7.37	8.11	8.59	9.25
Metallurgical coal	7.25	8.48	8.43	8.42	9.57	9.51	9.57	10.21	10.20	10.43
Other industrial coal	3.24	3.58	3.59	3.61	3.86	3.88	3.95	4.16	4.19	4.26
Coal to liquids	- -	- -	- -	- -	- -	- -	- -	- -	- -	- -
Electricity	19.50	20.54	20.77	20.98	21.45	21.99	22.77	22.94	24.05	25.45
Transportation										
Propane	25.14	24.82	24.85	25.45	26.51	26.81	27.08	28.14	28.82	29.20
E85[3]	35.06	25.36	25.61	27.09	25.63	27.91	29.07	29.82	35.49	36.50
Motor gasoline[4]	30.68	25.48	25.59	26.22	27.98	28.54	28.90	30.76	32.67	33.65
Jet fuel[5]	22.99	19.12	19.47	19.95	22.89	23.71	24.33	26.92	28.07	29.36
Diesel fuel (distillate fuel oil)[6]	28.80	26.44	26.80	27.38	30.07	30.68	31.22	33.34	34.53	35.85
Residual fuel oil	20.07	12.26	12.46	12.67	15.08	15.50	15.83	17.91	18.55	19.41
Natural gas[7]	14.64	15.44	15.62	16.41	15.95	16.63	17.25	18.26	19.67	20.83
Electricity	31.43	29.38	29.86	30.23	31.08	31.68	32.54	32.45	34.19	35.88
Electric power[8]										
Distillate fuel oil	24.12	20.27	20.66	21.19	23.77	24.65	25.25	27.39	28.81	30.14
Residual fuel oil	20.68	13.65	13.86	13.98	16.72	17.14	17.46	19.76	20.42	21.32
Natural gas	3.44	5.06	5.07	5.37	6.04	6.49	6.89	7.63	8.16	8.78
Steam coal	2.39	2.59	2.61	2.64	2.90	2.93	2.95	3.16	3.19	3.24
Average price to all users[9]										
Propane	23.24	22.51	22.54	23.02	24.30	24.66	25.00	26.12	26.79	27.24
E85[3]	35.06	25.36	25.61	27.09	25.63	27.91	29.07	29.82	35.49	36.50
Motor gasoline[4]	30.44	25.48	25.58	26.22	27.97	28.53	28.90	30.76	32.67	33.64
Jet fuel[5]	22.99	19.12	19.47	19.95	22.89	23.71	24.33	26.92	28.07	29.36
Distillate fuel oil	28.36	25.33	25.70	26.30	28.99	29.67	30.24	32.32	33.54	34.94
Residual fuel oil	20.41	12.95	13.15	13.36	15.85	16.32	16.68	18.74	19.42	20.34
Natural gas	5.38	7.15	7.09	7.42	8.10	8.49	8.86	9.81	10.38	11.16
Metallurgical coal	7.25	8.48	8.43	8.42	9.57	9.51	9.57	10.21	10.20	10.43
Other coal	2.44	2.66	2.67	2.70	2.96	2.98	3.02	3.22	3.25	3.31
Coal to liquids	- -	- -	- -	- -	- -	- -	- -	- -	- -	- -
Electricity	28.85	29.62	29.72	29.70	30.26	30.56	31.20	31.65	32.63	33.90
Non-renewable energy expenditures by sector (billion 2012 dollars)										
Residential	234.06	244.36	249.25	258.05	254.20	272.82	296.05	271.38	306.56	350.21
Commercial	173.25	187.07	189.44	192.88	208.45	215.91	225.21	239.06	255.39	273.61
Industrial[1]	213.75	265.70	279.45	299.80	306.22	343.02	376.63	342.35	390.91	450.69
Transportation	755.09	613.11	632.05	662.34	606.78	667.67	711.94	655.67	772.91	874.31
Total non-renewable expenditures	1,376.15	1,310.24	1,350.18	1,413.07	1,375.65	1,499.43	1,609.82	1,508.46	1,725.77	1,948.83
Transportation renewable expenditures	0.50	4.86	4.89	4.77	13.77	12.96	12.35	14.14	11.80	12.43
Total expenditures	**1,376.66**	**1,315.10**	**1,355.07**	**1,417.84**	**1,389.42**	**1,512.39**	**1,622.18**	**1,522.61**	**1,737.56**	**1,961.26**

Table B3. Energy prices by sector and source (continued)

(nominal dollars per million Btu, unless otherwise noted)

Sector and source	2012	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
Residential										
Propane	24.12	28.41	26.94	26.86	42.82	34.67	33.24	66.64	45.83	42.93
Distillate fuel oil	27.30	29.00	27.94	27.87	46.59	38.50	37.35	76.92	54.12	52.10
Natural gas	10.46	13.84	13.13	13.56	21.74	18.18	17.97	36.65	26.49	26.23
Electricity	34.83	43.29	40.94	39.97	62.12	49.78	47.70	94.41	64.39	61.06
Commercial										
Propane	20.75	24.26	23.02	23.08	37.69	30.68	29.55	60.30	41.74	39.29
Distillate fuel oil	26.81	25.59	24.66	24.93	41.89	34.54	33.51	69.64	49.27	47.65
Residual fuel oil	22.84	16.97	16.31	16.11	29.25	24.12	23.33	50.10	34.80	33.58
Natural gas	8.11	11.36	10.75	11.06	18.03	15.07	14.84	30.16	21.68	21.38
Electricity	29.55	36.38	34.88	34.37	51.56	42.08	41.21	77.65	54.73	53.32
Industrial[1]										
Propane	21.09	24.64	23.38	23.45	38.45	31.32	30.20	61.77	42.83	40.37
Distillate fuel oil	27.41	26.14	25.17	25.26	42.83	35.15	34.04	70.79	49.61	47.93
Residual fuel oil	20.90	17.55	16.85	16.68	29.98	24.62	23.77	51.17	35.61	34.32
Natural gas[2]	3.77	6.98	6.56	6.75	11.06	9.41	9.41	19.96	14.25	14.19
Metallurgical coal	7.25	10.14	9.55	9.34	16.10	12.81	12.22	25.13	16.91	16.00
Other industrial coal	3.24	4.28	4.07	4.00	6.50	5.23	5.05	10.22	6.95	6.54
Coal to liquids	- -	- -	- -	- -	- -	- -	- -	- -	- -	- -
Electricity	19.50	24.56	23.52	23.28	36.09	29.60	29.09	56.45	39.88	39.03
Transportation										
Propane	25.14	29.68	28.14	28.23	44.59	36.09	34.60	69.24	47.79	44.78
E85[3]	35.06	30.32	29.00	30.05	43.12	37.57	37.14	73.38	58.85	55.99
Motor gasoline[4]	30.68	30.46	28.98	29.09	47.06	38.42	36.92	75.69	54.17	51.61
Jet fuel[5]	22.99	22.87	22.06	22.14	38.51	31.91	31.08	66.24	46.53	45.04
Diesel fuel (distillate fuel oil)[6]	28.80	31.62	30.35	30.38	50.59	41.30	39.89	82.02	57.25	54.99
Residual fuel oil	20.07	14.66	14.11	14.05	25.37	20.86	20.23	44.06	30.76	29.77
Natural gas[7]	14.64	18.46	17.69	18.21	26.83	22.38	22.04	44.93	32.61	31.95
Electricity	31.43	35.13	33.82	33.54	52.29	42.65	41.56	79.83	56.68	55.04
Electric power[8]										
Distillate fuel oil	24.12	24.23	23.40	23.51	39.98	33.18	32.26	67.38	47.77	46.22
Residual fuel oil	20.68	16.33	15.70	15.51	28.13	23.08	22.30	48.61	33.86	32.70
Natural gas	3.44	6.05	5.75	5.96	10.16	8.74	8.80	18.76	13.53	13.47
Steam coal	2.39	3.10	2.96	2.93	4.88	3.94	3.77	7.78	5.29	4.97

Table B3. Energy prices by sector and source (continued)

(nominal dollars per million Btu, unless otherwise noted)

Sector and source	2012	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	23.24	26.91	25.53	25.54	40.88	33.20	31.93	64.27	44.42	41.78
E85[3]	35.06	30.32	29.00	30.05	43.12	37.57	37.14	73.38	58.85	55.99
Motor gasoline[4]	30.44	30.46	28.98	29.09	47.06	38.41	36.92	75.68	54.17	51.60
Jet fuel[5]	22.99	22.87	22.06	22.14	38.51	31.91	31.08	66.24	46.53	45.04
Distillate fuel oil	28.36	30.29	29.11	29.18	48.78	39.94	38.63	79.52	55.61	53.60
Residual fuel oil	20.41	15.48	14.90	14.82	26.67	21.97	21.31	46.10	32.20	31.20
Natural gas	5.38	8.55	8.04	8.23	13.62	11.43	11.32	24.13	17.22	17.12
Metallurgical coal	7.25	10.14	9.55	9.34	16.10	12.81	12.22	25.13	16.91	16.00
Other coal	2.44	3.17	3.03	2.99	4.97	4.02	3.86	7.92	5.39	5.08
Coal to liquids	- -	- -	- -	- -	- -	- -	- -	- -	- -	- -
Electricity	28.85	35.42	33.66	32.95	50.90	41.13	39.85	77.86	54.11	52.00
Non-renewable energy expenditures by sector (billion nominal dollars)										
Residential	234.06	292.19	282.30	286.31	427.62	367.27	378.21	667.71	508.27	537.16
Commercial	173.25	223.69	214.56	214.01	350.66	290.65	287.71	588.19	423.44	419.68
Industrial[1]	213.75	317.71	316.50	332.63	515.14	461.77	481.15	842.31	648.12	691.29
Transportation	755.09	733.13	715.87	734.87	1,020.75	898.80	909.52	1,613.19	1,281.47	1,341.05
Total non-renewable expenditures	1,376.15	1,566.72	1,529.23	1,567.81	2,314.17	2,018.49	2,056.59	3,711.39	2,861.30	2,989.19
Transportation renewable expenditures	0.50	5.81	5.54	5.29	23.16	17.45	15.78	34.80	19.56	19.06
Total expenditures	**1,376.66**	**1,572.53**	**1,534.77**	**1,573.10**	**2,337.33**	**2,035.94**	**2,072.36**	**3,746.19**	**2,880.86**	**3,008.25**

[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 fuel in motor vehicles, trains, and ships. Price 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 2012 are model results and may differ from official EIA data reports.
Sources: 2012 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(2013/08) (Washington, DC, August 2013). 2012 residential, commercial, and industrial natural gas delivered prices: EIA, *Natural Gas Monthly*, DOE/EIA-0130(2013/06) (Washington, DC, June 2013). 2012 transportation sector natural gas delivered prices are model results. 2012 electric power sector distillate and residual fuel oil prices: EIA, *Monthly Energy Review*, DOE/EIA-0035(2013/09) (Washington, DC, September 2013). 2012 electric power sector natural gas prices: EIA, *Electric Power Monthly*, DOE/EIA-0226, April 2012 and April 2013, Table 4.2, and EIA, *State Energy Data Report 2011*, DOE/EIA-0214(2011) (Washington, DC, June 2013). 2012 coal prices based on: EIA, *Quarterly Coal Report, October-December 2012*, DOE/EIA-0121(2012/4Q) (Washington, DC, March 2013) and EIA, AEO2014 National Energy Modeling System run REF2014.D102413A. 2012 electricity prices: EIA, *Monthly Energy Review*, DOE/EIA-0035(2013/09) (Washington, DC, September 2013). 2012 E85 prices derived from monthly prices in the Clean Cities Alternative Fuel Price Report. **Projections:** EIA, AEO2014 National Energy Modeling System runs LOWMACRO.D112913A, REF2014.D102413A, and HIGHMACRO.D112913A.

Table B4. Macroeconomic indicators
(billion 2005 chain-weighted dollars, unless otherwise noted)

Indicators	2012	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	**13,593**	**15,918**	**16,753**	**17,594**	**18,910**	**21,139**	**22,725**	**23,158**	**26,670**	**29,154**
Components of real gross domestic product										
Real consumption	9,603	11,020	11,592	12,118	12,576	14,220	15,309	14,671	17,635	19,162
Real investment	1,914	2,554	2,876	3,256	3,174	3,740	4,288	4,137	4,925	5,702
Real government spending	2,481	2,374	2,443	2,505	2,425	2,623	2,708	2,587	2,917	3,005
Real exports	1,837	2,778	2,863	2,962	4,703	5,056	5,438	7,707	8,186	9,273
Real imports	2,238	2,738	2,925	3,127	3,746	4,213	4,667	5,339	6,328	7,128
Energy intensity										
(thousand Btu per 2005 dollar of GDP)										
Delivered energy	5.08	4.51	4.40	4.30	3.72	3.54	3.46	3.05	2.88	2.86
Total energy	6.99	6.18	6.01	5.87	5.17	4.89	4.76	4.25	3.99	3.95
Price indices										
GDP chain-type price index (2005=1.000)	1.154	1.380	1.307	1.280	1.941	1.553	1.474	2.839	1.913	1.770
Consumer price index (1982-4=1.00)										
All-urban	2.30	2.77	2.63	2.58	3.99	3.20	3.04	6.01	4.05	3.76
Energy commodities and services	2.46	2.68	2.55	2.54	4.08	3.33	3.21	6.51	4.56	4.39
Wholesale price index (1982=1.00)										
All commodities	2.02	2.35	2.22	2.20	3.28	2.62	2.51	4.79	3.21	3.06
Fuel and power	2.12	2.54	2.42	2.41	4.00	3.30	3.23	6.72	4.73	4.61
Metals and metal products	2.20	2.54	2.43	2.51	3.41	2.77	2.75	4.67	3.22	3.28
Industrial commodities excluding energy	1.94	2.27	2.14	2.13	3.07	2.41	2.30	4.27	2.78	2.64
Interest rates (percent, nominal)										
Federal funds rate	0.14	5.28	3.85	3.40	7.03	4.14	3.63	7.45	4.22	3.85
10-year treasury note	1.80	6.02	4.14	3.61	7.26	4.36	3.83	7.84	4.52	4.05
AA utility bond rate	3.83	8.91	6.60	5.59	10.42	6.88	5.99	11.30	7.22	6.35
Value of shipments (billion 2005 dollars)										
Non-industrial and service sectors	21,359	24,672	26,033	27,492	28,252	31,782	34,301	31,742	37,135	40,577
Total industrial	6,147	7,439	7,960	8,614	8,400	9,537	10,672	9,475	10,994	12,985
Agriculture, mining, and construction	1,623	2,011	2,226	2,470	2,040	2,389	2,717	2,159	2,551	2,945
Manufacturing	4,525	5,428	5,735	6,144	6,360	7,148	7,955	7,315	8,443	10,041
Energy-intensive	1,616	1,861	1,931	2,012	2,003	2,171	2,292	2,105	2,303	2,484
Non-energy-intensive	2,909	3,567	3,803	4,131	4,358	4,977	5,663	5,210	6,140	7,557
Total shipments	**27,506**	**32,111**	**33,994**	**36,105**	**36,651**	**41,319**	**44,973**	**41,217**	**48,129**	**53,563**
Population and employment (millions)										
Population, with armed forces overseas	314.6	332.9	334.5	336.3	354.6	359.0	364.1	372.8	380.5	389.4
Population, aged 16 and over	249.2	265.6	266.7	268.0	284.4	287.6	291.4	301.4	307.3	314.0
Population, over age 65	43.4	56.2	56.2	56.3	72.7	73.0	73.3	79.1	79.8	80.6
Employment, nonfarm	133.7	145.4	148.4	153.5	155.0	158.6	166.4	163.0	169.2	178.4
Employment, manufacturing	11.9	12.2	12.8	13.7	11.1	12.5	13.9	9.5	11.0	13.1
Key labor indicators										
Labor force (millions)	155.0	162.4	163.5	165.0	168.3	170.9	174.7	176.9	181.2	189.8
Non-farm labor productivity (1992=1.00)	1.11	1.21	1.25	1.27	1.41	1.53	1.58	1.64	1.85	1.94
Unemployment rate (percent)	8.08	5.87	5.49	5.07	5.38	5.10	4.80	5.27	5.12	4.72
Key indicators for energy demand										
Real disposable personal income	10,304	12,212	12,710	13,204	14,681	15,926	16,752	17,688	19,724	20,650
Housing starts (millions)	0.84	1.25	1.75	2.38	1.09	1.71	2.50	1.02	1.66	2.59
Commercial floorspace (billion square feet)	82.4	88.6	89.1	89.8	96.5	98.2	100.0	105.6	108.9	112.3
Unit sales of light-duty vehicles (millions)	14.43	15.16	16.23	17.06	15.49	17.23	17.93	15.27	17.93	19.42

GDP = Gross domestic product.
Btu = British thermal unit.
Sources: 2012: IHS Global Insight, Global Insight Industry and Employment models, May 2013. **Projections:** U.S. Energy Information Administration, AEO2014 National Energy Modeling System runs LOWMACRO.D112913A, REF2014.D102413A, and HIGHMACRO.D112913A.

Appendix C

Price case comparisons

Table C1. Total energy supply, disposition, and price summary
(quadrillion Btu per year, unless otherwise noted)

Supply, disposition, and prices	2012	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	13.87	19.06	20.36	22.76	14.60	17.71	19.80	12.41	16.00	17.55
Natural gas plant liquids	3.21	3.47	3.54	3.62	3.80	3.98	4.18	3.69	3.99	4.17
Dry natural gas	24.59	28.18	29.73	30.60	31.92	35.19	39.44	33.89	38.37	42.37
Coal[1]	20.60	21.75	21.70	21.30	22.70	22.61	22.32	23.08	22.61	23.23
Nuclear / uranium[2]	8.05	8.15	8.15	8.15	8.16	8.18	8.22	8.41	8.49	9.37
Hydropower	2.67	2.80	2.81	2.80	2.86	2.87	2.88	2.90	2.90	2.92
Biomass[3]	3.78	4.52	4.66	4.74	5.16	5.29	5.31	5.52	5.61	5.63
Other renewable energy[4]	1.97	2.98	3.01	3.07	3.22	3.23	3.32	3.94	3.89	4.50
Other[5]	0.41	0.27	0.24	0.23	0.29	0.24	0.23	0.29	0.24	0.23
Total	**79.15**	**91.20**	**94.19**	**97.28**	**92.71**	**99.30**	**105.70**	**94.13**	**102.09**	**109.96**
Imports										
Crude oil	18.57	15.06	13.15	9.40	19.49	15.00	10.61	22.99	17.43	12.69
Petroleum and other liquids[6]	4.26	4.74	4.21	3.72	4.99	4.08	3.29	5.58	3.93	3.00
Natural gas[7]	3.21	2.37	2.39	2.46	1.95	2.01	1.95	2.34	2.28	2.12
Other imports[8]	0.36	0.14	0.17	0.57	0.12	0.12	0.16	0.09	0.10	0.27
Total	**26.40**	**22.31**	**19.92**	**16.16**	**26.55**	**21.22**	**16.01**	**31.00**	**23.73**	**18.08**
Exports										
Petroleum and other liquids[9]	6.29	6.51	6.30	5.93	7.39	6.91	6.54	8.09	7.70	7.26
Natural gas[10]	1.63	3.04	4.30	4.69	4.34	6.96	9.92	5.33	8.09	10.89
Coal	3.22	3.14	3.13	3.10	3.61	3.55	3.29	4.15	3.79	3.33
Total	**11.14**	**12.69**	**13.73**	**13.72**	**15.34**	**17.42**	**19.74**	**17.57**	**19.58**	**21.48**
Discrepancy[11]	**-0.61**	**-0.28**	**-0.35**	**-0.34**	**-0.12**	**-0.17**	**-0.16**	**0.06**	**-0.07**	**-0.14**
Consumption										
Petroleum and other liquids[12]	35.87	37.64	36.86	35.44	37.19	35.65	33.13	38.16	35.35	32.69
Natural gas	26.20	27.36	27.65	28.20	29.36	30.03	31.24	30.66	32.32	32.98
Coal[13]	17.34	18.58	18.56	18.60	19.03	19.01	19.02	18.84	18.75	19.58
Nuclear / uranium[2]	8.05	8.15	8.15	8.15	8.16	8.18	8.22	8.41	8.49	9.37
Hydropower	2.67	2.80	2.81	2.80	2.86	2.87	2.88	2.90	2.90	2.92
Biomass[14]	2.53	3.24	3.35	3.45	3.87	3.95	3.98	4.24	4.26	4.28
Other renewable energy[4]	1.97	2.98	3.01	3.07	3.22	3.23	3.32	3.94	3.89	4.50
Other[15]	0.39	0.34	0.34	0.34	0.35	0.35	0.35	0.35	0.35	0.39
Total	**95.02**	**101.10**	**100.73**	**100.06**	**104.04**	**103.27**	**102.14**	**107.49**	**106.31**	**106.71**
Prices (2012 dollars per unit)										
Crude oil spot prices (dollars per barrel)										
Brent	111.65	68.90	96.57	150.28	71.90	118.99	173.69	74.90	141.46	204.24
West Texas Intermediate	94.12	66.90	94.57	148.28	69.90	116.99	171.69	72.90	139.46	202.24
Natural gas at Henry Hub (dollars per million Btu)	2.75	4.35	4.38	4.73	5.75	6.03	6.88	7.43	7.65	8.34
Coal (dollars per ton) at the minemouth[16]	39.94	45.43	46.52	48.49	51.20	53.15	55.00	56.67	59.16	60.51
Coal (dollars per million Btu) at the minemouth[16]	1.98	2.27	2.33	2.42	2.58	2.67	2.75	2.85	2.96	3.04
Average end-use[17]	2.60	2.76	2.85	2.99	3.03	3.17	3.30	3.25	3.43	3.60
Average electricity (cents per kilowatthour)	9.8	10.1	10.1	10.3	10.4	10.4	10.7	11.1	11.1	11.7

Table C1. Total energy supply, disposition, and price summary (continued)
(quadrillion Btu per year, unless otherwise noted)

Supply, disposition, and prices	2012	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	111.65	77.64	109.37	171.98	94.64	160.19	243.19	119.51	234.53	351.41
West Texas Intermediate	94.12	75.39	107.11	169.69	92.01	157.49	240.39	116.32	231.22	347.97
Natural gas at Henry Hub (dollars per million Btu)	2.75	4.90	4.96	5.41	7.57	8.12	9.64	11.86	12.69	14.34
Coal (dollars per ton) at the minemouth[16]	39.94	51.20	52.69	55.49	67.39	71.55	77.01	90.42	98.08	104.11
Coal (dollars per million Btu) at the minemouth[16]	1.98	2.56	2.63	2.77	3.40	3.59	3.86	4.54	4.91	5.23
Average end-use[17]	2.60	3.11	3.23	3.42	3.99	4.27	4.63	5.18	5.68	6.20
Average electricity (cents per kilowatthour)	9.8	11.3	11.5	11.8	13.6	14.0	15.0	17.6	18.5	20.1

[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]Estimated consumption. 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 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 2012 are model results and may differ from official EIA data reports.
Sources: 2012 natural gas supply values: U.S. Energy Information Administration (EIA), *Natural Gas Monthly*, DOE/EIA-0130(2013/06) (Washington, DC, June 2013). 2012 coal minemouth and delivered coal prices: EIA, *Annual Coal Report 2012*, DOE/EIA-0584(2012) (Washington, DC, December 2013). 2012 petroleum supply values: EIA, *Petroleum Supply Annual 2012*, DOE/EIA-0340(2012)/1 (Washington, DC, September 2013). 2012 crude oil spot prices and natural gas spot price at Henry Hub: Thomson Reuters. Other 2012 coal values: *Quarterly Coal Report, October-December 2012*, DOE/EIA-0121(2012/4Q) (Washington, DC, March 2013). Other 2012 values: EIA, *Monthly Energy Review*, DOE/EIA-0035(2013/09) (Washington, DC, September 2013). **Projections:** EIA, AEO2014 National Energy Modeling System runs LOWPRICE.D120613A, REF2014.D102413A, and HIGHPRICE.D120613A.

Table C2. Energy consumption by sector and source
(quadrillion Btu per year, unless otherwise noted)

Sector and source	2012	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	0.51	0.43	0.42	0.42	0.39	0.38	0.37	0.36	0.35	0.34
Kerosene	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Distillate fuel oil	0.51	0.48	0.46	0.43	0.40	0.37	0.35	0.34	0.31	0.29
Petroleum and other liquids subtotal	1.02	0.91	0.89	0.85	0.79	0.75	0.72	0.70	0.66	0.63
Natural gas	4.26	4.57	4.56	4.54	4.44	4.43	4.39	4.22	4.21	4.16
Renewable energy[1]	0.45	0.41	0.46	0.55	0.37	0.44	0.51	0.33	0.42	0.48
Electricity	4.69	4.86	4.84	4.81	5.23	5.21	5.16	5.69	5.65	5.57
Delivered energy	**10.42**	**10.75**	**10.74**	**10.75**	**10.82**	**10.83**	**10.78**	**10.95**	**10.94**	**10.85**
Electricity related losses	9.68	9.67	9.64	9.59	10.05	10.00	9.96	10.61	10.55	10.60
Total	**20.10**	**20.42**	**20.38**	**20.34**	**20.88**	**20.83**	**20.75**	**21.56**	**21.48**	**21.45**
Commercial										
Propane	0.15	0.17	0.16	0.15	0.18	0.17	0.16	0.19	0.18	0.17
Motor gasoline[2]	0.05	0.05	0.04	0.04	0.05	0.05	0.05	0.06	0.05	0.05
Kerosene	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.00	0.00
Distillate fuel oil	0.40	0.43	0.40	0.35	0.42	0.38	0.33	0.43	0.37	0.32
Residual fuel oil	0.04	0.09	0.08	0.06	0.10	0.08	0.06	0.10	0.08	0.06
Petroleum and other liquids subtotal	0.63	0.74	0.68	0.61	0.76	0.67	0.60	0.79	0.68	0.60
Natural gas	2.96	3.25	3.23	3.22	3.36	3.35	3.32	3.66	3.65	3.59
Coal	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04
Renewable energy[3]	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13
Electricity	4.52	4.70	4.69	4.67	5.19	5.18	5.14	5.74	5.72	5.66
Delivered energy	**8.29**	**8.86**	**8.78**	**8.68**	**9.48**	**9.38**	**9.24**	**10.36**	**10.22**	**10.02**
Electricity related losses	9.32	9.35	9.34	9.32	9.97	9.94	9.93	10.70	10.66	10.75
Total	**17.61**	**18.21**	**18.12**	**18.00**	**19.46**	**19.32**	**19.17**	**21.06**	**20.88**	**20.78**
Industrial[4]										
Liquefied petroleum gases and other[5]	2.25	2.86	2.90	2.97	2.87	3.05	3.18	2.79	2.90	3.10
Motor gasoline[2]	0.26	0.30	0.30	0.30	0.29	0.30	0.29	0.30	0.29	0.29
Distillate fuel oil	1.20	1.40	1.40	1.38	1.42	1.41	1.36	1.45	1.42	1.36
Residual fuel oil	0.10	0.17	0.14	0.12	0.19	0.15	0.13	0.21	0.15	0.13
Petrochemical feedstocks	0.75	1.27	1.27	1.27	1.58	1.62	1.62	1.49	1.59	1.70
Other petroleum[6]	3.50	3.67	3.56	3.38	3.83	3.58	3.34	4.10	3.75	3.46
Petroleum and other liquids subtotal	8.06	9.66	9.56	9.43	10.19	10.10	9.92	10.33	10.10	10.04
Natural gas	7.29	8.11	8.26	8.40	8.54	8.71	8.57	8.49	8.87	8.74
Natural-gas-to-liquids heat and power	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.40
Lease and plant fuel[7]	1.45	1.57	1.77	1.90	1.77	2.16	2.84	1.83	2.41	3.11
Natural gas subtotal	8.75	9.69	10.04	10.29	10.32	10.87	11.42	10.32	11.28	12.26
Metallurgical coal	0.55	0.57	0.58	0.59	0.55	0.55	0.53	0.49	0.47	0.46
Other industrial coal	0.93	0.98	0.99	0.99	0.99	1.00	1.00	1.00	1.01	1.02
Coal-to-liquids heat and power	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.56
Net coal coke imports	0.00	0.00	0.00	0.01	-0.03	-0.03	-0.03	-0.05	-0.05	-0.04
Coal subtotal	1.48	1.56	1.57	1.59	1.51	1.52	1.51	1.44	1.44	2.01
Biofuels heat and coproducts	0.52	0.76	0.76	0.75	0.79	0.79	0.78	0.78	0.79	0.78
Renewable energy[8]	1.48	1.74	1.74	1.74	2.05	2.01	1.93	2.38	2.28	2.20
Electricity	3.35	4.02	4.04	4.09	4.31	4.33	4.27	4.34	4.34	4.33
Delivered energy	**23.63**	**27.43**	**27.71**	**27.90**	**29.18**	**29.62**	**29.82**	**29.59**	**30.22**	**31.61**
Electricity related losses	6.91	8.01	8.05	8.16	8.30	8.33	8.25	8.10	8.10	8.22
Total	**30.54**	**35.44**	**35.76**	**36.05**	**37.48**	**37.94**	**38.07**	**37.69**	**38.33**	**39.83**

Table C2. Energy consumption by sector and source (continued)
(quadrillion Btu per year, unless otherwise noted)

Sector and source	2012	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
Transportation										
Propane	0.05	0.04	0.05	0.06	0.05	0.06	0.07	0.05	0.07	0.08
Motor gasoline[2]	16.33	15.61	15.00	14.05	13.81	12.69	11.52	13.69	12.09	10.88
of which: E85[9]	0.01	0.13	0.19	0.29	0.30	0.46	0.59	0.27	0.33	0.56
Jet fuel[10]	3.00	3.08	3.08	3.07	3.20	3.20	3.19	3.29	3.28	3.27
Distillate fuel oil[11]	5.82	6.69	6.70	6.47	7.47	7.25	6.18	8.36	7.54	6.24
Residual fuel oil	0.58	0.58	0.58	0.58	0.59	0.59	0.59	0.60	0.60	0.60
Other petroleum[12]	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15
Petroleum and other liquids subtotal	25.93	26.15	25.55	24.38	25.27	23.94	21.70	26.14	23.73	21.22
Pipeline fuel natural gas	0.73	0.71	0.74	0.76	0.76	0.82	0.86	0.78	0.85	0.89
Compressed / liquefied natural gas	0.04	0.07	0.08	0.43	0.08	0.28	1.44	0.10	0.86	2.32
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	0.06	0.07
Delivered energy	**26.72**	**26.97**	**26.40**	**25.60**	**26.16**	**25.08**	**24.05**	**27.08**	**25.50**	**24.51**
Electricity related losses	0.05	0.06	0.06	0.07	0.08	0.08	0.09	0.10	0.12	0.14
Total	**26.77**	**27.03**	**26.47**	**25.66**	**26.23**	**25.17**	**24.15**	**27.18**	**25.62**	**24.65**
Delivered energy consumption for all sectors										
Liquefied petroleum gases and other[5]	2.96	3.50	3.53	3.60	3.49	3.65	3.77	3.39	3.49	3.68
Motor gasoline[2]	16.64	15.95	15.34	14.39	14.16	13.04	11.85	14.05	12.44	11.22
of which: E85[9]	0.01	0.13	0.19	0.29	0.30	0.46	0.59	0.27	0.33	0.56
Jet fuel[10]	3.00	3.08	3.08	3.07	3.20	3.20	3.19	3.29	3.28	3.27
Kerosene	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Distillate fuel oil	7.93	9.00	8.95	8.64	9.71	9.41	8.23	10.58	9.63	8.21
Residual fuel oil	0.72	0.85	0.80	0.77	0.88	0.82	0.78	0.92	0.83	0.80
Petrochemical feedstocks	0.75	1.27	1.27	1.27	1.58	1.62	1.62	1.49	1.59	1.70
Other petroleum[13]	3.64	3.81	3.70	3.52	3.97	3.73	3.48	4.24	3.89	3.61
Petroleum and other liquids subtotal	35.64	37.46	36.68	35.27	37.00	35.47	32.94	37.97	35.17	32.50
Natural gas	14.56	16.00	16.14	16.59	16.43	16.77	17.72	16.47	17.59	18.81
Natural-gas-to-liquids heat and power	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.40
Lease and plant fuel[7]	1.45	1.57	1.77	1.90	1.77	2.16	2.84	1.83	2.41	3.11
Pipeline natural gas	0.73	0.71	0.74	0.76	0.76	0.82	0.86	0.78	0.85	0.89
Natural gas subtotal	16.74	18.28	18.65	19.24	18.96	19.75	21.42	19.08	20.84	23.21
Metallurgical coal	0.55	0.57	0.58	0.59	0.55	0.55	0.53	0.49	0.47	0.46
Other coal	0.98	1.03	1.03	1.04	1.03	1.04	1.05	1.04	1.05	1.07
Coal-to-liquids heat and power	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.56
Net coal coke imports	0.00	0.00	0.00	0.01	-0.03	-0.03	-0.03	-0.05	-0.05	-0.04
Coal subtotal	1.53	1.60	1.61	1.64	1.55	1.56	1.55	1.48	1.48	2.05
Biofuels heat and coproducts	0.52	0.76	0.76	0.75	0.79	0.79	0.78	0.78	0.79	0.78
Renewable energy[14]	2.06	2.28	2.33	2.42	2.56	2.58	2.58	2.84	2.83	2.82
Liquid hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Electricity	12.58	13.61	13.60	13.60	14.77	14.76	14.62	15.83	15.77	15.63
Delivered energy	**69.07**	**74.00**	**73.63**	**72.93**	**75.64**	**74.91**	**73.89**	**77.98**	**76.88**	**76.99**
Electricity related losses	25.95	27.10	27.10	27.13	28.40	28.35	28.25	29.51	29.43	29.71
Total	**95.02**	**101.10**	**100.73**	**100.06**	**104.04**	**103.27**	**102.14**	**107.49**	**106.31**	**106.71**
Electric power[15]										
Distillate fuel oil	0.05	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09
Residual fuel oil	0.18	0.09	0.09	0.09	0.09	0.09	0.09	0.11	0.10	0.10
Petroleum and other liquids subtotal	0.23	0.18	0.18	0.18	0.18	0.18	0.18	0.19	0.19	0.19
Natural gas	9.46	9.08	9.00	8.96	10.40	10.28	9.81	11.58	11.48	9.76
Steam coal	15.82	16.98	16.95	16.96	17.48	17.44	17.47	17.37	17.27	17.53
Nuclear / uranium[16]	8.05	8.15	8.15	8.15	8.16	8.18	8.22	8.41	8.49	9.37
Renewable energy[17]	4.59	5.98	6.08	6.15	6.60	6.68	6.83	7.45	7.44	8.11
Non-biogenic municipal waste	0.23	0.23	0.23	0.23	0.23	0.23	0.23	0.23	0.23	0.23
Electricity imports	0.16	0.11	0.11	0.11	0.12	0.12	0.12	0.12	0.12	0.16
Total	**38.53**	**40.71**	**40.70**	**40.74**	**43.16**	**43.12**	**42.87**	**45.34**	**45.20**	**45.34**

Table C2. Energy consumption by sector and source (continued)
(quadrillion Btu per year, unless otherwise noted)

Sector and source	2012	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 and other[5]	2.96	3.50	3.53	3.60	3.49	3.65	3.77	3.39	3.49	3.68
Motor gasoline[2]	16.64	15.95	15.34	14.39	14.16	13.04	11.85	14.05	12.44	11.22
of which: E85[9]	0.01	0.13	0.19	0.29	0.30	0.46	0.59	0.27	0.33	0.56
Jet fuel[10]	3.00	3.08	3.08	3.07	3.20	3.20	3.19	3.29	3.28	3.27
Kerosene	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Distillate fuel oil	7.98	9.09	9.03	8.73	9.79	9.50	8.31	10.66	9.72	8.29
Residual fuel oil	0.90	0.94	0.89	0.86	0.98	0.91	0.88	1.03	0.93	0.90
Petrochemical feedstocks	0.75	1.27	1.27	1.27	1.58	1.62	1.62	1.49	1.59	1.70
Other petroleum[13]	3.64	3.81	3.70	3.52	3.97	3.73	3.48	4.24	3.89	3.61
Petroleum and other liquids subtotal	35.87	37.64	36.86	35.44	37.19	35.65	33.13	38.16	35.35	32.69
Natural gas	24.02	25.07	25.14	25.55	26.82	27.05	27.53	28.05	29.07	28.58
Natural-gas-to-liquids heat and power	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.40
Lease and plant fuel[7]	1.45	1.57	1.77	1.90	1.77	2.16	2.84	1.83	2.41	3.11
Pipeline natural gas	0.73	0.71	0.74	0.76	0.76	0.82	0.86	0.78	0.85	0.89
Natural gas subtotal	26.20	27.36	27.65	28.20	29.36	30.03	31.24	30.66	32.32	32.98
Metallurgical coal	0.55	0.57	0.58	0.59	0.55	0.55	0.53	0.49	0.47	0.46
Other coal	16.79	18.01	17.98	18.00	18.51	18.49	18.52	18.41	18.32	18.59
Coal-to-liquids heat and power	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.56
Net coal coke imports	0.00	0.00	0.00	0.01	-0.03	-0.03	-0.03	-0.05	-0.05	-0.04
Coal subtotal	17.34	18.58	18.56	18.60	19.03	19.01	19.02	18.84	18.75	19.58
Nuclear / uranium[16]	8.05	8.15	8.15	8.15	8.16	8.18	8.22	8.41	8.49	9.37
Biofuels heat and coproducts	0.52	0.76	0.76	0.75	0.79	0.79	0.78	0.78	0.79	0.78
Renewable energy[18]	6.65	8.26	8.40	8.57	9.16	9.26	9.41	10.29	10.27	10.93
Liquid hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Non-biogenic municipal waste	0.23	0.23	0.23	0.23	0.23	0.23	0.23	0.23	0.23	0.23
Electricity imports	0.16	0.11	0.11	0.11	0.12	0.12	0.12	0.12	0.12	0.16
Total	**95.02**	**101.10**	**100.73**	**100.06**	**104.04**	**103.27**	**102.14**	**107.49**	**106.31**	**106.71**
Energy use and related statistics										
Delivered energy use	69.07	74.00	73.63	72.93	75.64	74.91	73.89	77.98	76.88	76.99
Total energy use	95.02	101.10	100.73	100.06	104.04	103.27	102.14	107.49	106.31	106.71
Ethanol consumed in motor gasoline and E85	1.09	1.22	1.22	1.21	1.25	1.25	1.24	1.25	1.29	1.31
Population (millions)	314.58	334.47	334.47	334.47	359.03	359.03	359.03	380.53	380.53	380.53
Gross domestic product (billion 2005 dollars)	13,593	16,739	16,753	16,812	21,150	21,139	21,100	26,725	26,670	26,772
Carbon dioxide emissions (million metric tons)	5,290	5,523	5,476	5,401	5,621	5,527	5,401	5,746	5,599	5,475

[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 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 ethane, natural gasoline, and refinery olefins.
[6]Includes petroleum coke, asphalt, road oil, lubricants, still gas, and miscellaneous petroleum products.
[7]Represents natural gas used in well, field, and lease operations, in natural gas processing plant machinery, and for liquefaction in export facilities.
[8]Includes consumption of energy produced from hydroelectric, wood and wood waste, municipal waste, and other biomass sources. Excludes ethanol in motor gasoline.
[9]E85 refers to a blend of 85 percent ethanol (renewable) and 15 percent motor gasoline (nonrenewable). To address cold starting issues, the percentage of ethanol varies seasonally. The annual average ethanol content of 74 percent is used for this forecast.
[10]Includes only kerosene type.
[11]Diesel fuel for on- and off- road use.
[12]Includes aviation gasoline and lubricants.
[13]Includes aviation gasoline, petroleum coke, asphalt, road oil, lubricants, still gas, and miscellaneous petroleum products.
[14]Includes electricity generated for sale to the grid and for own use from renewable sources, and non-electric energy from renewable sources. Excludes ethanol and nonmarketed renewable energy consumption for geothermal heat pumps, buildings photovoltaic systems, and solar thermal water heaters.
[15]Includes consumption of energy by electricity-only and combined heat and power plants that have a regulatory status.
[16]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.
[17]Includes conventional hydroelectric, geothermal, wood and wood waste, biogenic municipal waste, other biomass, wind, photovoltaic, and solar thermal sources. Excludes net electricity imports.
[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: Includes estimated consumption for petroleum and other liquids. Totals may not equal sum of components due to independent rounding. Data for 2012 are model results and may differ from official EIA data reports.
Sources: 2012 consumption based on: U.S. Energy Information Administration (EIA), *Monthly Energy Review*, DOE-EIA-0035(2013/09) (Washington, DC, September 2013). 2012 population and gross domestic product: IHS Global Insight Industry and Employment models, May 2013. 2012 carbon dioxide emissions and emission factors: EIA, *Monthly Energy Review*, DOE/EIA-0035(2013/09) (Washington, DC, September 2013). **Projections:** EIA, AEO2014 National Energy Modeling System runs LOWPRICE.D120613A, REF2014.D102413A, and HIGHPRICE.D120613A.

Table C3. Energy prices by sector and source
(2012 dollars per million Btu, unless otherwise noted)

Sector and source	2012	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	24.12	22.39	23.79	25.81	23.38	25.75	28.16	24.24	27.64	29.79
Distillate fuel oil	27.30	19.42	24.67	34.47	20.14	28.60	38.28	20.70	32.64	43.67
Natural gas	10.46	11.58	11.59	11.91	13.32	13.50	14.02	15.76	15.98	17.01
Electricity	34.83	35.80	36.15	36.73	36.70	36.98	37.81	38.53	38.83	40.50
Commercial										
Propane	20.75	18.60	20.33	22.87	19.78	22.79	25.93	20.80	25.17	28.11
Distillate fuel oil	26.81	16.64	21.77	31.50	17.38	25.66	35.27	17.87	29.72	40.58
Residual fuel oil	22.84	10.41	14.40	22.09	11.17	17.92	25.57	11.73	20.99	30.45
Natural gas	8.11	9.45	9.49	9.79	10.95	11.19	11.62	12.85	13.08	14.20
Electricity	29.55	30.53	30.80	31.28	31.07	31.26	31.98	32.82	33.01	34.56
Industrial[1]										
Propane	21.09	18.85	20.64	23.33	20.23	23.27	26.61	21.65	25.84	28.95
Distillate fuel oil	27.41	17.04	22.22	31.89	17.72	26.11	35.68	18.11	29.92	40.96
Residual fuel oil	20.90	10.84	14.88	22.60	11.54	18.29	25.97	12.15	21.48	30.80
Natural gas[2]	3.77	5.70	5.79	6.11	6.70	6.99	7.67	8.48	8.59	9.53
Metallurgical coal	7.25	8.34	8.43	8.60	9.38	9.51	9.65	10.05	10.20	10.38
Other industrial coal	3.24	3.51	3.59	3.72	3.76	3.88	4.04	4.02	4.19	4.36
Coal to liquids	- -	- -	- -	- -	- -	- -	- -	- -	- -	3.16
Electricity	19.50	20.54	20.77	21.17	21.75	21.99	22.71	23.86	24.05	25.41
Transportation										
Propane	25.14	23.49	24.85	26.88	24.52	26.81	29.22	25.43	28.82	30.84
E85[3]	35.06	22.62	25.61	33.07	24.13	27.91	34.30	26.08	35.49	40.38
Motor gasoline[4]	30.68	21.22	25.59	34.56	21.23	28.54	37.08	21.79	32.67	42.21
Jet fuel[5]	22.99	14.26	19.47	29.11	15.29	23.71	32.98	16.09	28.07	38.74
Diesel fuel (distillate fuel oil)[6]	28.80	21.63	26.80	36.44	22.33	30.68	40.19	22.73	34.53	45.47
Residual fuel oil	20.07	8.73	12.46	19.50	9.40	15.50	22.49	10.00	18.55	26.71
Natural gas[7]	14.64	16.00	15.62	18.62	16.68	16.63	19.78	17.80	19.67	21.46
Electricity	31.43	29.74	29.86	30.17	31.41	31.68	32.47	33.74	34.19	36.24
Electric power[8]										
Distillate fuel oil	24.12	15.46	20.66	30.47	16.25	24.65	34.31	16.86	28.81	39.77
Residual fuel oil	20.68	9.88	13.86	21.50	10.48	17.14	24.95	10.78	20.42	29.76
Natural gas	3.44	5.00	5.07	5.35	6.20	6.49	7.05	8.05	8.16	8.98
Steam coal	2.39	2.52	2.61	2.75	2.79	2.93	3.06	3.00	3.19	3.40
Average price to all users[9]										
Propane	23.24	20.99	22.54	24.84	21.99	24.66	27.45	22.80	26.79	29.34
E85[3]	35.06	22.62	25.61	33.07	24.13	27.91	34.30	26.08	35.49	40.38
Motor gasoline[4]	30.44	21.22	25.58	34.56	21.22	28.53	37.08	21.78	32.67	42.21
Jet fuel[5]	22.99	14.26	19.47	29.11	15.29	23.71	32.98	16.09	28.07	38.74
Distillate fuel oil	28.36	20.51	25.70	35.36	21.30	29.67	39.14	21.79	33.54	44.42
Residual fuel oil	20.41	9.39	13.15	20.34	10.10	16.32	23.48	10.70	19.42	27.91
Natural gas	5.38	7.03	7.09	7.55	8.16	8.49	9.57	10.00	10.38	11.96
Metallurgical coal	7.25	8.34	8.43	8.60	9.38	9.51	9.65	10.05	10.20	10.38
Other coal	2.44	2.59	2.67	2.81	2.85	2.98	3.12	3.07	3.25	3.46
Coal to liquids	- -	- -	- -	- -	- -	- -	- -	- -	- -	3.16
Electricity	28.85	29.46	29.72	30.17	30.34	30.56	31.33	32.42	32.63	34.15
Non-renewable energy expenditures by sector (billion 2012 dollars)										
Residential	234.06	245.83	249.25	256.46	268.11	272.82	280.40	301.65	306.56	319.45
Commercial	173.25	186.48	189.44	195.36	211.31	215.91	222.46	249.84	255.39	268.38
Industrial[1]	213.75	249.82	279.45	335.52	285.52	343.02	407.85	312.95	390.91	479.52
Transportation	755.09	527.76	632.05	827.37	514.23	667.67	809.67	548.77	772.91	923.38
Total non-renewable expenditures	1,376.15	1,209.88	1,350.18	1,614.71	1,279.17	1,499.43	1,720.37	1,413.21	1,725.77	1,990.73
Transportation renewable expenditures	0.50	2.85	4.89	9.50	7.27	12.96	20.25	7.05	11.80	22.66
Total expenditures	**1,376.66**	**1,212.74**	**1,355.07**	**1,624.21**	**1,286.44**	**1,512.39**	**1,740.62**	**1,420.26**	**1,737.56**	**2,013.39**

Table C3. Energy prices by sector and source (continued)
(nominal dollars per million Btu, unless otherwise noted)

Sector and source	2012	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	24.12	25.22	26.94	29.54	30.77	34.67	39.43	38.67	45.83	51.25
Distillate fuel oil	27.30	21.89	27.94	39.45	26.51	38.50	53.60	33.02	54.12	75.14
Natural gas	10.46	13.05	13.13	13.62	17.53	18.18	19.62	25.15	26.49	29.27
Electricity	34.83	40.34	40.94	42.04	48.31	49.78	52.93	61.48	64.39	69.68
Commercial										
Propane	20.75	20.97	23.02	26.17	26.04	30.68	36.31	33.19	41.74	48.37
Distillate fuel oil	26.81	18.75	24.66	36.05	22.87	34.54	49.38	28.51	49.27	69.82
Residual fuel oil	22.84	11.73	16.31	25.27	14.70	24.12	35.80	18.71	34.80	52.39
Natural gas	8.11	10.65	10.75	11.20	14.42	15.07	16.27	20.51	21.68	24.43
Electricity	29.55	34.40	34.88	35.80	40.89	42.08	44.78	52.37	54.73	59.46
Industrial[1]										
Propane	21.09	21.24	23.38	26.70	26.63	31.32	37.26	34.54	42.83	49.82
Distillate fuel oil	27.41	19.20	25.17	36.50	23.33	35.15	49.96	28.89	49.61	70.48
Residual fuel oil	20.90	12.21	16.85	25.87	15.19	24.62	36.36	19.39	35.61	52.99
Natural gas[2]	3.77	6.42	6.56	7.00	8.82	9.41	10.73	13.53	14.25	16.40
Metallurgical coal	7.25	9.40	9.55	9.84	12.35	12.81	13.51	16.04	16.91	17.87
Other industrial coal	3.24	3.95	4.07	4.26	4.94	5.23	5.66	6.42	6.95	7.51
Coal to liquids	- -	- -	- -	- -	- -	- -	- -	- -	- -	5.44
Electricity	19.50	23.14	23.52	24.23	28.63	29.60	31.80	38.07	39.88	43.73
Transportation										
Propane	25.14	26.48	28.14	30.75	32.27	36.09	40.91	40.57	47.79	53.06
E85[3]	35.06	25.49	29.00	37.84	31.77	37.57	48.02	41.61	58.85	69.48
Motor gasoline[4]	30.68	23.91	28.98	39.55	27.94	38.42	51.91	34.76	54.17	72.63
Jet fuel[5]	22.99	16.07	22.06	33.32	20.12	31.91	46.18	25.67	46.53	66.66
Diesel fuel (distillate fuel oil)[6]	28.80	24.38	30.35	41.70	29.39	41.30	56.27	36.26	57.25	78.23
Residual fuel oil	20.07	9.84	14.11	22.31	12.37	20.86	31.48	15.95	30.76	45.96
Natural gas[7]	14.64	18.03	17.69	21.31	21.95	22.38	27.69	28.40	32.61	36.92
Electricity	31.43	33.51	33.82	34.52	41.34	42.65	45.46	53.83	56.68	62.36
Electric power[8]										
Distillate fuel oil	24.12	17.42	23.40	34.87	21.40	33.18	48.04	26.91	47.77	68.43
Residual fuel oil	20.68	11.13	15.70	24.60	13.79	23.08	34.94	17.19	33.86	51.21
Natural gas	3.44	5.63	5.75	6.12	8.16	8.74	9.87	12.84	13.53	15.46
Steam coal	2.39	2.84	2.96	3.14	3.67	3.94	4.29	4.79	5.29	5.84

Table C3. Energy prices by sector and source (continued)
(nominal dollars per million Btu, unless otherwise noted)

Sector and source	2012	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	23.24	23.65	25.53	28.42	28.95	33.20	38.44	36.38	44.42	50.48
E85[3]	35.06	25.49	29.00	37.84	31.77	37.57	48.02	41.61	58.85	69.48
Motor gasoline[4]	30.44	23.91	28.98	39.55	27.94	38.41	51.91	34.76	54.17	72.62
Jet fuel[5]	22.99	16.07	22.06	33.32	20.12	31.91	46.18	25.67	46.53	66.66
Distillate fuel oil	28.36	23.12	29.11	40.47	28.04	39.94	54.81	34.77	55.61	76.43
Residual fuel oil	20.41	10.58	14.90	23.27	13.30	21.97	32.87	17.07	32.20	48.03
Natural gas	5.38	7.92	8.04	8.64	10.75	11.43	13.40	15.96	17.22	20.57
Metallurgical coal	7.25	9.40	9.55	9.84	12.35	12.81	13.51	16.04	16.91	17.87
Other coal	2.44	2.91	3.03	3.21	3.75	4.02	4.37	4.89	5.39	5.94
Coal to liquids	- -	- -	- -	- -	- -	- -	- -	- -	- -	5.44
Electricity	28.85	33.19	33.66	34.52	39.94	41.13	43.87	51.73	54.11	58.76
Non-renewable energy expenditures by sector (billion nominal dollars)										
Residential	234.06	277.02	282.30	293.48	352.89	367.27	392.59	481.30	508.27	549.64
Commercial	173.25	210.13	214.56	223.56	278.14	290.65	311.47	398.63	423.44	461.77
Industrial[1]	213.75	281.51	316.50	383.95	375.82	461.77	571.03	499.33	648.12	825.06
Transportation	755.09	594.71	715.87	946.80	676.84	898.80	1,133.62	875.60	1,281.47	1,588.74
Total non-renewable expenditures	1,376.15	1,363.37	1,529.23	1,847.79	1,683.69	2,018.49	2,408.71	2,254.86	2,861.30	3,425.20
Transportation renewable expenditures	0.50	3.21	5.54	10.87	9.57	17.45	28.36	11.24	19.56	38.98
Total expenditures	**1,376.66**	**1,366.59**	**1,534.77**	**1,858.66**	**1,693.26**	**2,035.94**	**2,437.07**	**2,266.10**	**2,880.86**	**3,464.18**

[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 fuel in motor vehicles, trains, and ships. Price 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 2012 are model results and may differ from official EIA data reports.
Sources: 2012 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(2013/08) (Washington, DC, August 2013). 2012 residential, commercial, and industrial natural gas delivered prices: EIA, *Natural Gas Monthly*, DOE/EIA-0130(2013/06) (Washington, DC, June 2013). 2012 transportation sector natural gas delivered prices are model results. 2012 electric power sector distillate and residual fuel oil prices: EIA, *Monthly Energy Review*, DOE/EIA-0035(2013/09) (Washington, DC, September 2013). 2012 electric power sector natural gas prices: EIA, *Electric Power Monthly*, DOE/EIA-0226, April 2012 and April 2013, Table 4.2, and EIA, *State Energy Data Report 2011*, DOE/EIA-0214(2011) (Washington, DC, June 2013). 2012 coal prices based on: EIA, *Quarterly Coal Report, October-December 2012*, DOE/EIA-0121(2012/4Q) (Washington, DC, March 2013) and EIA, AEO2014 National Energy Modeling System run REF2014.D102413A. 2012 electricity prices: EIA, *Monthly Energy Review*, DOE/EIA-0035(2013/09) (Washington, DC, September 2013). 2012 E85 prices derived from monthly prices in the Clean Cities Alternative Fuel Price Report. **Projections:** EIA, AEO2014 National Energy Modeling System runs LOWPRICE.D120613A, REF2014.D102413A, and HIGHPRICE.D120613A.

Table C4. Petroleum and other liquids supply and disposition
(million barrels per day, unless otherwise noted)

Supply and disposition	2012	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]	6.49	8.95	9.55	10.69	6.85	8.30	9.28	5.81	7.48	8.21
Alaska	0.53	0.44	0.44	0.44	0.00	0.24	0.55	0.00	0.26	0.40
Lower 48 states	5.96	8.51	9.12	10.25	6.85	8.06	8.73	5.81	7.22	7.81
Net imports	8.43	6.65	5.79	4.09	8.65	6.64	4.66	10.26	7.74	5.61
Gross imports	8.49	6.80	5.94	4.25	8.78	6.77	4.79	10.38	7.87	5.73
Exports	0.06	0.15	0.15	0.15	0.13	0.13	0.13	0.12	0.12	0.12
Other crude supply[2]	0.09	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total crude supply	**15.01**	**15.59**	**15.34**	**14.78**	**15.50**	**14.94**	**13.94**	**16.07**	**15.22**	**13.81**
Other petroleum supply	**0.10**	**0.41**	**0.23**	**0.06**	**-0.05**	**-0.34**	**-0.65**	**-0.12**	**-0.86**	**-1.20**
Net product imports	-0.92	-0.70	-0.86	-0.92	-1.11	-1.29	-1.49	-1.18	-1.82	-2.04
Gross refined product imports[3]	0.85	1.10	0.98	0.92	1.27	1.06	0.88	1.52	1.10	0.89
Unfinished oil imports	0.60	0.59	0.52	0.43	0.62	0.49	0.37	0.62	0.45	0.31
Blending component imports	0.62	0.68	0.62	0.52	0.60	0.50	0.40	0.62	0.40	0.31
Exports	2.98	3.08	2.97	2.79	3.60	3.33	3.14	3.95	3.76	3.54
Refinery processing gain[4]	1.08	1.11	1.08	0.97	1.05	0.96	0.84	1.06	0.95	0.83
Product stock withdrawal	-0.06	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Other non-petroleum supply	**3.48**	**3.90**	**3.96**	**4.00**	**4.19**	**4.32**	**4.43**	**4.11**	**4.36**	**4.88**
Supply from renewable sources	0.89	1.01	1.01	1.01	1.03	1.04	1.03	1.04	1.07	1.09
Ethanol	0.83	0.90	0.90	0.88	0.89	0.91	0.90	0.92	0.95	0.97
Domestic production	0.84	0.85	0.84	0.81	0.84	0.86	0.83	0.86	0.86	0.86
Net imports	-0.02	0.05	0.06	0.07	0.05	0.06	0.07	0.06	0.08	0.11
Stock withdrawal	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Biodiesel	0.06	0.07	0.09	0.09	0.06	0.09	0.09	0.06	0.09	0.10
Domestic production	0.06	0.06	0.08	0.08	0.05	0.08	0.08	0.05	0.08	0.08
Net imports	0.00	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Stock withdrawal	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Other biomass-derived liquids[5]	0.00	0.04	0.03	0.04	0.08	0.04	0.05	0.06	0.03	0.02
Domestic production	0.00	0.04	0.03	0.04	0.08	0.04	0.05	0.06	0.03	0.02
Net imports	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Stock withdrawal	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Liquids from gas	2.40	2.60	2.65	2.71	2.85	2.98	3.12	2.76	2.98	3.32
Natural gas plant liquids	2.40	2.60	2.65	2.71	2.85	2.98	3.12	2.76	2.98	3.11
Gas-to-liquids	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.20
Liquids from coal	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.20
Other[6]	0.19	0.29	0.30	0.28	0.31	0.30	0.28	0.31	0.31	0.27
Total primary supply[7]	**18.59**	**19.90**	**19.52**	**18.84**	**19.64**	**18.93**	**17.72**	**20.06**	**18.72**	**17.49**
Product supplied										
by fuel										
Liquefied petroleum gases and other[8]	2.32	2.70	2.73	2.79	2.71	2.84	2.94	2.63	2.73	2.88
Motor gasoline[9]	8.71	8.67	8.35	7.85	7.73	7.15	6.52	7.67	6.84	6.20
of which: E85[10]	0.01	0.09	0.13	0.20	0.21	0.32	0.41	0.19	0.23	0.39
Jet fuel[11]	1.40	1.49	1.49	1.49	1.55	1.55	1.55	1.59	1.59	1.59
Distillate fuel oil[12]	3.74	4.32	4.30	4.15	4.66	4.52	3.95	5.07	4.62	3.95
of which: Diesel	3.45	3.95	3.94	3.82	4.33	4.21	3.67	4.76	4.34	3.69
Residual fuel oil	0.35	0.41	0.39	0.37	0.43	0.40	0.38	0.45	0.40	0.39
Other[13]	1.97	2.32	2.28	2.20	2.57	2.49	2.38	2.64	2.55	2.49
by sector										
Residential and commercial	0.94	0.92	0.88	0.83	0.87	0.81	0.76	0.84	0.76	0.71
Industrial[14]	4.42	5.39	5.37	5.35	5.69	5.72	5.69	5.70	5.68	5.74
Transportation	13.44	13.51	13.19	12.59	13.01	12.32	11.20	13.42	12.20	10.96
Electric power[15]	0.10	0.08	0.08	0.08	0.08	0.08	0.08	0.09	0.08	0.08
Total	**18.49**	**19.91**	**19.53**	**18.84**	**19.65**	**18.94**	**17.73**	**20.06**	**18.73**	**17.50**
Discrepancy[16]	0.11	-0.01	-0.01	-0.01	-0.01	-0.01	-0.01	0.00	-0.01	-0.01

Table C4. Petroleum and other liquids supply and disposition (continued)
(million barrels per day, unless otherwise noted)

Supply and disposition	2012	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[17]	17.3	18.1	18.1	18.1	18.1	18.1	18.1	18.1	18.1	18.1
Capacity utilization rate (percent)[18]	89.0	86.0	84.6	81.5	85.5	82.4	76.9	88.6	84.0	76.2
Net import share of product supplied (percent)	40.3	30.2	25.6	17.3	38.8	28.6	18.3	45.6	32.2	21.1
Net expenditures for imported crude oil and petroleum products (billion 2012 dollars)	313.70	160.27	198.85	226.18	214.45	278.60	290.21	264.46	385.39	408.21

[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]Includes ethane, natural gasoline, and refinery olefins.
[9]Includes ethanol and ethers blended into gasoline.
[10]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.
[11]Includes only kerosene type.
[12]Includes distillate fuel oil from petroleum and biomass feedstocks.
[13]Includes Kerosene, aviation gasoline, petrochemical feedstocks, lubricants, waxes, asphalt, road oil, still gas, special naphthas, petroleum coke, crude oil product supplied, methanol, and miscellaneous petroleum products.
[14]Includes energy for combined heat and power plants that have a non-regulatory status, and small on-site generating systems.
[15]Includes consumption of energy by electricity-only and combined heat and power plants that have a regulatory status.
[16]Balancing item. Includes unaccounted for supply, losses, and gains.
[17]End-of-year operable capacity.
[18]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 2012 are model results and may differ from official EIA data reports.
Sources: 2012 product supplied based on: U.S. Energy Information Administration (EIA), *Monthly Energy Review*, DOE/EIA-0035(2013/09) (Washington, DC, September 2013). Other 2012 data: EIA, *Petroleum Supply Annual 2012*, DOE/EIA-0340(2012)/1 (Washington, DC, September 2013). **Projections:** EIA, AEO2014 National Energy Modeling System runs LOWPRICE.D120613A, REF2014.D102413A, and HIGHPRICE.D120613A.

Table C5. Petroleum and other liquids prices
(2012 dollars per gallon, unless otherwise noted)

Sector and fuel	2012	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 (2012 dollars per barrel)										
Brent spot	111.65	68.90	96.57	150.28	71.90	118.99	173.69	74.90	141.46	204.24
West Texas Intermediate spot	94.12	66.90	94.57	148.28	69.90	116.99	171.69	72.90	139.46	202.24
Average imported refiners acquisition cost[1]	101.10	61.93	88.07	139.34	64.73	109.22	160.61	67.84	130.80	190.62
Delivered sector product prices										
Residential										
Propane	2.20	2.04	2.17	2.36	2.14	2.35	2.57	2.21	2.52	2.72
Distillate fuel oil	3.79	2.69	3.42	4.78	2.79	3.97	5.31	2.87	4.53	6.06
Commercial										
Distillate fuel oil	3.70	2.29	3.00	4.34	2.40	3.54	4.86	2.46	4.10	5.59
Residual fuel oil	3.42	1.56	2.16	3.31	1.67	2.68	3.83	1.76	3.14	4.56
Residual fuel oil (2012 dollars per barrel)	143.59	65.46	90.53	138.85	70.23	112.66	160.76	73.73	131.97	191.43
Industrial[2]										
Propane	1.93	1.72	1.89	2.13	1.85	2.13	2.43	1.98	2.36	2.64
Distillate fuel oil	3.76	2.34	3.05	4.38	2.43	3.58	4.90	2.49	4.11	5.62
Residual fuel oil	3.13	1.62	2.23	3.38	1.73	2.74	3.89	1.82	3.22	4.61
Residual fuel oil (2012 dollars per barrel)	131.40	68.13	93.56	142.11	72.54	115.00	163.27	76.40	135.04	193.63
Transportation										
Propane	2.30	2.15	2.27	2.45	2.24	2.45	2.67	2.32	2.63	2.82
Ethanol (E85)[3]	3.33	2.15	2.43	3.14	2.29	2.65	3.26	2.48	3.37	3.84
Ethanol wholesale price	2.58	2.58	2.66	2.81	2.50	2.52	2.63	2.34	2.65	2.80
Motor gasoline[4]	3.69	2.55	3.08	4.16	2.55	3.43	4.45	2.61	3.90	5.04
Jet fuel[5]	3.10	1.93	2.63	3.93	2.06	3.20	4.45	2.17	3.79	5.23
Diesel fuel (distillate fuel oil)[6]	3.95	2.96	3.67	4.99	3.06	4.20	5.51	3.11	4.73	6.23
Residual fuel oil	3.00	1.31	1.86	2.92	1.41	2.32	3.37	1.50	2.78	4.00
Residual fuel oil (2012 dollars per barrel)	126.17	54.90	78.31	122.57	59.10	97.43	141.38	62.85	116.65	167.94
Electric power[7]										
Distillate fuel oil	3.35	2.14	2.87	4.23	2.25	3.42	4.76	2.34	4.00	5.52
Residual fuel oil	3.10	1.48	2.07	3.22	1.57	2.57	3.74	1.61	3.06	4.45
Residual fuel oil (2012 dollars per barrel)	130.00	62.10	87.12	135.14	65.87	107.77	156.88	67.74	128.40	187.11
Average prices, all sectors[8]										
Propane	2.12	1.92	2.06	2.27	2.01	2.25	2.51	2.08	2.45	2.68
Motor gasoline[4]	3.66	2.55	3.08	4.16	2.55	3.43	4.45	2.61	3.90	5.04
Jet fuel[5]	3.10	1.93	2.63	3.93	2.06	3.20	4.45	2.17	3.79	5.23
Distillate fuel oil	3.89	2.81	3.53	4.85	2.92	4.07	5.37	2.99	4.60	6.09
Residual fuel oil	3.05	1.41	1.97	3.04	1.51	2.44	3.51	1.60	2.91	4.18
Residual fuel oil (2012 dollars per barrel)	128.30	59.05	82.69	127.85	63.52	102.60	147.61	67.25	122.12	175.49
Average	**3.28**	**2.27**	**2.80**	**3.81**	**2.32**	**3.19**	**4.17**	**2.42**	**3.69**	**4.79**

Table C5. Petroleum and other liquids prices (continued)

(nominal dollars per gallon, unless otherwise noted)

Sector and fuel	2012	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	111.65	77.64	109.37	171.98	94.64	160.19	243.19	119.51	234.53	351.41
West Texas Intermediate spot	94.12	75.39	107.11	169.69	92.01	157.49	240.39	116.32	231.22	347.97
Average imported refiners acquisition cost[1]	101.10	69.79	99.75	159.45	85.20	147.02	224.87	108.25	216.87	327.97
Delivered sector product prices										
Residential										
Propane	2.20	2.30	2.46	2.70	2.81	3.17	3.60	3.53	4.19	4.68
Distillate fuel oil	3.79	3.04	3.88	5.47	3.68	5.34	7.43	4.58	7.51	10.42
Commercial										
Distillate fuel oil	3.70	2.59	3.40	4.97	3.15	4.76	6.81	3.93	6.79	9.63
Residual fuel oil	3.42	1.76	2.44	3.78	2.20	3.61	5.36	2.80	5.21	7.84
Industrial[2]										
Propane	1.93	1.94	2.14	2.44	2.43	2.86	3.40	3.15	3.91	4.55
Distillate fuel oil	3.76	2.64	3.46	5.01	3.20	4.82	6.86	3.97	6.81	9.67
Residual fuel oil	3.13	1.83	2.52	3.87	2.27	3.69	5.44	2.90	5.33	7.93
Transportation										
Propane	2.30	2.42	2.57	2.81	2.95	3.30	3.74	3.71	4.36	4.85
Ethanol (E85)[3]	3.33	2.42	2.76	3.60	3.02	3.57	4.56	3.96	5.59	6.60
Ethanol wholesale price	2.58	2.91	3.02	3.22	3.29	3.39	3.68	3.73	4.39	4.82
Motor gasoline[4]	3.69	2.88	3.49	4.76	3.36	4.61	6.23	4.17	6.47	8.68
Jet fuel[5]	3.10	2.17	2.98	4.50	2.72	4.31	6.23	3.47	6.28	9.00
Diesel fuel (distillate fuel oil)[6]	3.95	3.34	4.16	5.71	4.03	5.66	7.71	4.97	7.84	10.72
Residual fuel oil	3.00	1.47	2.11	3.34	1.85	3.12	4.71	2.39	4.60	6.88
Electric power[7]										
Distillate fuel oil	3.35	2.42	3.25	4.84	2.97	4.60	6.66	3.73	6.62	9.49
Residual fuel oil	3.10	1.67	2.35	3.68	2.06	3.45	5.23	2.57	5.07	7.67
Average prices, all sectors[8]										
Propane	2.12	2.16	2.33	2.60	2.64	3.03	3.51	3.32	4.06	4.61
Motor gasoline[4]	3.66	2.88	3.49	4.76	3.36	4.61	6.23	4.17	6.47	8.67
Jet fuel[5]	3.10	2.17	2.98	4.50	2.72	4.31	6.23	3.47	6.28	9.00
Distillate fuel oil	3.89	3.17	3.99	5.55	3.85	5.48	7.52	4.77	7.63	10.48
Residual fuel oil (nominal dollars per barrel)	128.30	66.54	93.65	146.31	83.60	138.12	206.68	107.31	202.47	301.95
Average	**3.28**	**2.56**	**3.17**	**4.36**	**3.05**	**4.30**	**5.84**	**3.85**	**6.11**	**8.24**

[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 2012 are model results and may differ from official EIA data reports.
Sources: 2012 Brent and West Texas Intermediate crude oil spot prices: Thomson Reuters. 2012 average imported crude oil cost: Energy Information Administration (EIA), *Monthly Energy Review*, DOE/EIA-0035Monthly Energy Review. 2012 prices for motor gasoline, distillate fuel oil, and jet fuel are based on: EIA, *Petroleum Marketing Monthly*, DOE/EIA-0380(2013/08) (Washington, DC, August 2013). 2012 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." 2012 electric power prices based on: *Monthly Energy Review*, DOE/EIA-0035(2013/09) (Washington, DC, September 2013). 2012 E85 prices derived from monthly prices in the Clean Cities Alternative Fuel Price Report. 2012 wholesale ethanol prices derived from Bloomberg U.S. average rack price. **Projections:** EIA, AEO2014 National Energy Modeling System runs LOWPRICE.D120613A, REF2014.D102413A, and HIGHPRICE.D120613A.

Table C6. International petroleum and other liquids supply, disposition, and prices
(million barrels per day, unless otherwise noted)

Supply, disposition, and prices	2012	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										
(2012 dollars per barrel)										
Brent	111.65	68.90	96.57	150.28	71.90	118.99	173.69	74.90	141.46	204.24
West Texas Intermediate	94.12	66.90	94.57	148.28	69.90	116.99	171.69	72.90	139.46	202.24
(nominal dollars per barrel)										
Brent	111.65	77.64	109.37	171.98	94.64	160.19	243.19	119.51	234.53	351.41
West Texas Intermediate	94.12	75.39	107.11	169.69	92.01	157.49	240.39	116.32	231.22	347.97
Petroleum and other liquids consumption[1]										
OECD										
United States (50 states)	18.21	19.61	19.23	18.55	19.35	18.63	17.43	19.76	18.42	17.18
United States territories	0.25	0.31	0.29	0.28	0.35	0.33	0.32	0.39	0.37	0.36
Canada	2.26	2.35	2.24	2.15	2.36	2.18	2.13	2.46	2.30	2.31
Mexico and Chile	2.51	2.78	2.71	2.61	3.32	3.08	3.02	4.00	3.63	3.60
OECD Europe[2]	14.21	14.47	13.85	13.30	15.06	13.94	13.49	15.80	14.32	13.93
Japan	4.75	4.75	4.50	4.28	4.69	4.29	4.13	4.49	4.05	3.90
South Korea	2.65	2.74	2.76	2.65	2.97	2.68	2.58	3.18	2.76	2.68
Australia and New Zealand	1.28	1.22	1.23	1.18	1.28	1.21	1.19	1.40	1.30	1.28
Total OECD consumption	**46.13**	**48.23**	**46.82**	**45.01**	**49.39**	**46.37**	**44.30**	**51.47**	**47.15**	**45.22**
Non-OECD										
Russia	3.20	3.77	3.55	3.43	4.14	3.81	3.72	4.29	3.92	3.85
Other Europe and Eurasia[3]	1.99	2.52	2.32	2.25	2.88	2.62	2.54	3.45	3.08	3.00
China	10.36	13.90	13.91	13.63	16.49	17.04	17.73	18.78	20.48	22.98
India	3.68	4.58	4.50	4.38	6.52	6.11	6.19	8.89	8.33	8.94
Other Asia[4]	6.97	8.14	7.99	7.71	9.47	9.35	9.28	11.01	11.16	11.36
Middle East	7.67	8.64	8.81	8.54	9.15	9.22	9.22	10.00	10.38	10.74
Africa	3.47	3.79	3.70	3.55	4.16	4.03	3.93	4.52	4.58	4.54
Brazil	2.83	3.18	3.12	2.96	3.50	3.32	3.25	3.88	3.85	3.94
Other Central and South America	2.77	3.53	3.29	3.16	3.95	3.76	3.62	4.38	4.13	4.00
Total non-OECD consumption	**42.94**	**52.06**	**51.19**	**49.60**	**60.26**	**59.24**	**59.48**	**69.20**	**69.90**	**73.35**
Total consumption	**89.07**	**100.29**	**98.01**	**94.61**	**109.65**	**105.61**	**103.78**	**120.68**	**117.05**	**118.57**
Petroleum and other liquids production										
OPEC[5]										
Middle East	25.84	29.62	28.28	23.24	35.30	32.35	27.29	44.28	38.85	32.84
North Africa	3.36	3.74	3.19	2.95	3.99	3.43	3.25	4.62	3.96	3.69
West Africa	4.40	5.79	4.99	4.71	6.46	5.26	5.15	7.06	5.52	5.38
South America	2.99	3.56	3.10	2.98	4.13	3.01	2.98	5.10	3.31	3.24
Total OPEC production	**36.59**	**42.71**	**39.57**	**33.88**	**49.87**	**44.04**	**38.68**	**61.06**	**51.64**	**45.15**
Non-OPEC										
OECD										
United States (50 states)	10.84	13.63	14.25	15.30	11.73	13.23	14.19	10.63	12.42	13.52
Canada	4.00	5.18	5.10	6.00	6.15	5.92	7.24	5.77	6.21	7.81
Mexico and Chile	2.97	1.93	2.13	1.92	1.75	2.11	1.95	1.68	2.27	2.15
OECD Europe[2]	3.93	3.24	3.26	3.24	2.86	2.78	2.73	3.74	3.63	3.72
Japan and South Korea	0.18	0.18	0.16	0.17	0.20	0.18	0.18	0.21	0.19	0.19
Australia and New Zealand	0.57	0.53	0.54	0.52	0.56	0.56	0.55	0.83	0.92	0.93
Total OECD production	**22.48**	**24.69**	**25.44**	**27.15**	**23.25**	**24.78**	**26.84**	**22.85**	**25.64**	**28.31**
Non-OECD										
Russia	10.40	10.22	10.74	10.76	10.81	11.44	11.41	10.86	11.68	11.98
Other Europe and Eurasia[3]	3.19	3.86	3.73	3.89	4.02	4.44	4.50	3.56	5.44	5.54
China	4.37	4.49	4.91	4.56	5.51	5.50	5.80	5.63	5.62	8.43
Other Asia[4]	3.82	3.41	3.63	3.41	3.04	3.20	2.96	3.10	3.31	3.11
Middle East	1.31	1.19	0.98	1.18	1.07	0.77	1.03	0.95	0.71	0.95
Africa	2.34	2.91	2.61	2.95	2.97	2.57	2.96	3.32	2.91	3.41
Brazil	2.49	4.81	4.00	4.80	7.03	6.36	7.46	6.65	7.03	8.95
Other Central and South America	2.16	2.23	2.38	2.26	2.32	2.44	2.32	2.90	3.06	3.00
Total non-OECD production	**30.08**	**33.13**	**32.98**	**33.81**	**36.77**	**36.73**	**38.43**	**36.97**	**39.75**	**45.37**
Total petroleum and other liquids production	**89.15**	**100.53**	**97.99**	**94.84**	**109.89**	**105.55**	**103.95**	**120.89**	**117.03**	**118.83**
OPEC market share (percent)	41.0	42.5	40.4	35.7	45.4	41.7	37.2	50.5	44.1	38.0

Table C6. International petroleum and other liquids supply, disposition, and prices (continued)
(million barrels per day, unless otherwise noted)

Supply, disposition, and prices	2012	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
Selected world production subtotals:										
Petroleum										
Crude oil and equivalents[6]	75.78	85.10	82.35	79.06	91.71	87.58	85.40	99.82	96.56	95.06
Tight oil	2.40	5.28	5.81	6.78	5.79	6.88	7.42	6.04	7.28	9.00
Bitumen[7]	1.94	3.18	3.00	3.87	4.29	3.95	5.19	3.99	4.26	5.71
Refinery processing gain[8]	2.37	2.40	2.26	2.11	2.70	2.52	2.32	3.00	2.86	2.52
Liquids from renewable sources[9]	1.34	1.83	1.68	1.91	2.79	2.09	2.52	4.10	2.48	4.21
Liquids from coal[10]	0.19	0.36	0.40	0.53	0.82	0.91	1.15	0.98	1.12	2.78
Liquids from natural gas	9.21	10.36	10.78	10.76	11.56	12.19	12.39	12.37	13.29	13.56
Natural gas plant liquids	9.05	10.06	10.46	10.47	11.24	11.84	12.07	12.05	12.93	13.10
Gas-to-liquids[11]	0.16	0.30	0.31	0.29	0.32	0.35	0.32	0.31	0.35	0.46
Liquids from kerogen[12]	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Petroleum production[13]										
OPEC[5]										
Middle East	25.74	29.42	28.07	23.06	35.07	32.10	27.07	44.06	38.61	32.62
North Africa	3.36	3.74	3.19	2.95	3.99	3.43	3.25	4.62	3.96	3.69
West Africa	4.40	5.76	4.96	4.68	6.42	5.22	5.12	7.03	5.49	5.35
South America	2.99	3.56	3.10	2.98	4.13	3.01	2.98	5.10	3.31	3.24
Total OPEC production	**36.50**	**42.48**	**39.33**	**33.67**	**49.62**	**43.77**	**38.44**	**60.81**	**51.37**	**44.90**
Non-OPEC										
OECD										
United States (50 states)	10.00	12.66	13.28	14.37	10.75	12.24	13.24	9.64	11.42	12.15
Canada	3.97	5.15	5.08	5.97	6.09	5.88	7.19	5.69	6.17	7.73
Mexico and Chile	2.97	1.93	2.13	1.92	1.75	2.11	1.95	1.68	2.27	2.15
OECD Europe[2]	3.71	3.02	3.03	3.00	2.55	2.53	2.45	3.31	3.35	3.27
Japan and South Korea	0.17	0.18	0.15	0.16	0.19	0.17	0.17	0.19	0.18	0.18
Australia and New Zealand	0.56	0.52	0.53	0.51	0.54	0.55	0.54	0.81	0.91	0.91
Total OECD production	**21.39**	**23.46**	**24.21**	**25.93**	**21.87**	**23.49**	**25.55**	**21.32**	**24.30**	**26.39**
Non-OECD										
Russia	10.40	10.22	10.74	10.76	10.81	11.44	11.41	10.86	11.68	11.98
Other Europe and Eurasia[3]	3.19	3.85	3.73	3.89	4.01	4.44	4.49	3.55	5.43	5.53
China	4.32	4.35	4.77	4.27	4.76	4.82	4.83	4.60	4.72	6.04
Other Asia[4]	3.75	3.29	3.51	3.27	2.82	2.99	2.73	2.85	3.10	2.82
Middle East	1.31	1.19	0.98	1.18	1.07	0.77	1.03	0.95	0.71	0.95
Africa	2.13	2.61	2.28	2.61	2.66	2.22	2.58	3.02	2.55	3.01
Brazil	2.20	4.19	3.50	4.13	5.88	5.65	6.46	4.53	6.00	6.78
Other Central and South America	2.06	2.15	2.30	2.18	2.21	2.36	2.22	2.74	2.97	2.84
Total non-OECD production	**29.35**	**31.85**	**31.81**	**32.29**	**34.22**	**34.69**	**35.76**	**33.10**	**37.15**	**39.94**
Total petroleum production[13]	**87.24**	**97.79**	**95.34**	**91.90**	**105.71**	**101.95**	**99.75**	**115.23**	**112.82**	**111.23**
OPEC market share (percent)	41.8	43.4	41.2	36.6	46.9	42.9	38.5	52.8	45.5	40.4

[1]Estimated consumption. Includes both OPEC and non-OPEC consumers in the regional breakdown.
[2]OECD Europe - 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, India (for production), 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 the Petroleum Exporting Countries - Algeria, Angola, Ecuador, Iran, Iraq, Kuwait, Libya, Nigeria, Qatar, Saudi Arabia, the United Arab Emirates, and Venezuela.
[6]Includes crude oil, lease condensate, tight oil (shale oil), extra-heavy oil, and bitumen (oil sands).
[7]Includes diluted and upgraded/synthetic bitumen (syncrude).
[8]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.
[9]Includes liquids produced from energy crops.
[10]Includes liquids converted from coal via the Fischer-Tropsch coal-to-liquids process.
[11]Includes liquids converted from natural gas via the Fischer-Tropsch natural-gas-to-liquids process.
[12]Includes liquids produced from kerogen (oil shale, not to be confused with tight oil (shale oil)).
[13]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.
OECD = Organization for Economic Cooperation and Development.
Note: Ethanol is represented in motor gasoline equivalent barrels. Totals may not equal sum of components due to independent rounding. Data for 2012 are model results and may differ from official EIA data reports.
Sources: 2012 Brent and West Texas Intermediate crude oil spot prices: Thomson Reuters. **2012 quantities and projections:** Energy Information Administration (EIA), AEO2014 National Energy Modeling System runs LOWPRICE.D120613A, REF2014.D102413A, and HIGHPRICE.D120613A and EIA, Generate World Oil Balance Model.

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Results from side cases

Table D1. Key results for demand sector technology cases

Consumption, emissions, combined heat and power capacity and generation	2012	2020				2030			
		2013 Demand Technology	Reference	High Demand Technology	Best Available Demand Technology	2013 Demand Technology	Reference	High Demand Technology	Best Available Demand Technology
Energy consumption (quadrillion Btu)									
Residential									
Liquid fuels and other petroleum[1]	1.02	0.91	0.89	0.86	0.83	0.79	0.75	0.70	0.66
Natural gas	4.26	4.65	4.56	4.33	4.04	4.63	4.43	4.06	3.51
Renewable energy[2]	0.45	0.48	0.46	0.44	0.43	0.50	0.44	0.41	0.38
Electricity	4.69	5.00	4.84	4.47	4.15	5.56	5.21	4.53	4.13
Total residential	**10.42**	**11.04**	**10.74**	**10.10**	**9.45**	**11.48**	**10.83**	**9.70**	**8.68**
Nonmarketed renewables, residential	0.04	0.11	0.14	0.15	0.16	0.12	0.19	0.28	0.40
Commercial									
Liquid fuels and other petroleum[3]	0.63	0.68	0.68	0.67	0.67	0.67	0.67	0.65	0.65
Natural gas	2.96	3.23	3.23	3.20	3.20	3.32	3.35	3.34	3.31
Coal	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04
Renewable energy[4]	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13
Electricity	4.52	4.77	4.69	4.44	4.31	5.38	5.18	4.49	4.28
Total commercial	**8.29**	**8.86**	**8.78**	**8.50**	**8.35**	**9.55**	**9.38**	**8.66**	**8.42**
Nonmarketed renewables, commercial	0.13	0.18	0.18	0.22	0.23	0.20	0.24	0.35	0.43
Industrial[5]									
Liquefied petroleum gases and other[6]	2.25	2.91	2.90	2.88	2.91	3.07	3.05	3.04	3.07
Distillate fuel oil	1.20	1.46	1.40	1.36	1.38	1.54	1.41	1.35	1.39
Petrochemical feedstocks	0.75	1.29	1.27	1.27	1.28	1.65	1.62	1.60	1.63
Other petroleum[7]	3.86	4.12	4.00	3.92	3.99	4.26	4.02	3.92	4.03
Liquid fuels and other petroleum	8.06	9.77	9.56	9.43	9.56	10.53	10.10	9.92	10.12
Natural gas	8.75	10.41	10.04	10.07	10.04	11.70	10.87	10.89	10.90
Coal	1.48	1.62	1.57	1.54	1.58	1.64	1.52	1.46	1.57
Renewable energy[8]	2.00	2.47	2.50	2.54	2.51	2.72	2.79	2.94	2.82
Electricity	3.35	4.14	4.04	3.99	4.08	4.57	4.33	4.27	4.47
Total industrial	**23.63**	**28.42**	**27.71**	**27.57**	**27.77**	**31.17**	**29.62**	**29.47**	**29.88**
Transportation									
Motor gasoline[9]	16.33	14.99	15.00	14.88	15.00	12.64	12.69	12.54	12.71
of which: E85[10]	0.01	0.18	0.19	0.20	0.19	0.45	0.46	0.48	0.47
Jet fuel	3.00	3.08	3.08	3.06	3.08	3.20	3.20	3.16	3.20
Distillate fuel oil	5.82	6.70	6.70	6.58	6.68	7.20	7.25	7.08	7.32
Other petroleum[11]	0.77	0.78	0.78	0.77	0.78	0.80	0.80	0.79	0.80
Liquid fuels and other petroleum	25.93	25.55	25.55	25.30	25.53	23.84	23.94	23.57	24.04
Pipeline fuel natural gas	0.73	0.76	0.74	0.72	0.71	0.86	0.82	0.77	0.76
Compressed / liquefied natural gas	0.04	0.08	0.08	0.08	0.08	0.28	0.28	0.21	0.30
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	0.04
Total transportation	**26.72**	**26.42**	**26.40**	**26.13**	**26.36**	**25.02**	**25.08**	**24.59**	**25.14**
Electric power[12]									
Distillate and residual fuel oil	0.23	0.18	0.18	0.17	0.16	0.19	0.18	0.17	0.16
Natural gas	9.46	9.32	9.00	8.29	8.28	11.35	10.28	8.42	8.54
Steam coal	15.82	17.42	16.95	16.16	15.05	17.81	17.44	16.43	15.11
Nuclear / uranium[13]	8.05	8.15	8.15	8.15	8.15	8.20	8.18	8.15	8.15
Renewable energy[14]	4.59	6.15	6.08	5.69	5.55	7.17	6.68	6.18	6.02
Non-biogenic municipal waste	0.23	0.23	0.23	0.23	0.23	0.23	0.23	0.23	0.23
Net electricity imports	0.16	0.11	0.11	0.11	0.11	0.12	0.12	0.09	0.09
Total electric power	**38.53**	**41.56**	**40.70**	**38.81**	**37.54**	**45.07**	**43.12**	**39.68**	**38.30**
Total energy consumption									
Liquid fuels and other petroleum	35.87	37.09	36.86	36.42	36.76	36.02	35.65	35.01	35.63
Natural gas	26.20	28.45	27.65	26.69	26.35	32.14	30.03	27.68	27.31
Steam coal	17.34	19.08	18.56	17.74	16.67	19.50	19.01	17.93	16.73
Nuclear / uranium[13]	8.05	8.15	8.15	8.15	8.15	8.20	8.18	8.15	8.15
Renewable energy[15]	7.17	9.24	9.17	8.81	8.63	10.52	10.05	9.66	9.36
Other[16]	0.39	0.34	0.34	0.34	0.34	0.35	0.35	0.32	0.32
Total energy consumption	**95.02**	**102.35**	**100.73**	**98.16**	**96.90**	**106.74**	**103.27**	**98.76**	**97.50**

2040				Annual Growth 2012-2040 (percent)			
2013 Demand Technology	Reference	High Demand Technology	Best Available Demand Technology	2013 Demand Technology	Reference	High Demand Technology	Best Available Demand Technology
0.72	0.66	0.60	0.55	-1.2%	-1.5%	-1.9%	-2.2%
4.54	4.21	3.75	3.02	0.2%	0.0%	-0.5%	-1.2%
0.50	0.42	0.36	0.33	0.4%	-0.3%	-0.8%	-1.2%
6.15	5.65	4.92	4.36	1.0%	0.7%	0.2%	-0.3%
11.91	**10.94**	**9.64**	**8.26**	**0.5%**	**0.2%**	**-0.3%**	**-0.8%**
0.13	0.27	0.48	0.79	4.3%	6.9%	9.1%	11.1%
0.68	0.68	0.65	0.65	0.2%	0.2%	0.1%	0.1%
3.53	3.65	3.69	3.63	0.6%	0.7%	0.8%	0.7%
0.04	0.04	0.04	0.04	0.0%	0.0%	0.0%	0.0%
0.13	0.13	0.13	0.13	0.0%	0.0%	0.0%	0.0%
6.27	5.72	4.71	4.48	1.2%	0.8%	0.2%	0.0%
10.66	**10.22**	**9.24**	**8.93**	**0.9%**	**0.7%**	**0.4%**	**0.3%**
0.23	0.35	0.59	0.75	2.2%	3.7%	5.6%	6.5%
2.95	2.90	2.88	2.91	1.0%	0.9%	0.9%	0.9%
1.61	1.42	1.36	1.39	1.1%	0.6%	0.4%	0.5%
1.65	1.59	1.57	1.60	2.9%	2.7%	2.7%	2.7%
4.53	4.19	4.08	4.19	0.6%	0.3%	0.2%	0.3%
10.74	10.10	9.89	10.10	1.0%	0.8%	0.7%	0.8%
12.47	11.28	11.24	11.27	1.3%	0.9%	0.9%	0.9%
1.62	1.44	1.38	1.51	0.3%	-0.1%	-0.3%	0.1%
2.92	3.07	3.32	3.09	1.4%	1.5%	1.8%	1.6%
4.78	4.34	4.24	4.51	1.3%	0.9%	0.8%	1.1%
32.53	**30.22**	**30.06**	**30.47**	**1.1%**	**0.9%**	**0.9%**	**0.9%**
12.05	12.09	12.07	12.18	-1.1%	-1.1%	-1.1%	-1.0%
0.34	0.33	0.35	0.35	11.9%	11.9%	12.0%	12.1%
3.28	3.28	3.17	3.28	0.3%	0.3%	0.2%	0.3%
7.51	7.54	7.55	7.63	0.9%	0.9%	0.9%	1.0%
0.82	0.82	0.81	0.82	0.2%	0.2%	0.2%	0.2%
23.66	23.73	23.61	23.91	-0.3%	-0.3%	-0.3%	-0.3%
0.89	0.85	0.77	0.77	0.7%	0.5%	0.2%	0.2%
0.79	0.86	0.54	0.95	11.0%	11.3%	9.5%	11.7%
0.00	0.00	0.00	0.00	- -	- -	- -	- -
0.06	0.06	0.07	0.06	3.6%	3.6%	3.9%	3.6%
25.41	**25.50**	**24.99**	**25.70**	**-0.2%**	**-0.2%**	**-0.2%**	**-0.1%**
0.20	0.19	0.17	0.16	-0.5%	-0.8%	-1.1%	-1.3%
12.38	11.48	9.08	9.24	1.0%	0.7%	-0.1%	-0.1%
17.75	17.27	16.35	15.05	0.4%	0.3%	0.1%	-0.2%
9.32	8.49	8.25	8.15	0.5%	0.2%	0.1%	0.0%
9.30	7.44	6.51	6.33	2.6%	1.7%	1.3%	1.2%
0.23	0.23	0.23	0.23	0.0%	0.0%	0.0%	0.0%
0.14	0.12	0.10	0.10	-0.4%	-1.1%	-1.6%	-1.8%
49.32	**45.20**	**40.69**	**39.26**	**0.9%**	**0.6%**	**0.2%**	**0.1%**
36.00	35.35	34.91	35.37	0.0%	-0.1%	-0.1%	-0.1%
34.61	32.32	29.08	28.88	1.0%	0.8%	0.4%	0.3%
19.41	18.75	17.77	16.60	0.4%	0.3%	0.1%	-0.2%
9.32	8.49	8.25	8.15	0.5%	0.2%	0.1%	0.0%
12.86	11.05	10.32	9.88	2.1%	1.6%	1.3%	1.2%
0.37	0.35	0.33	0.33	-0.1%	-0.4%	-0.5%	-0.6%
112.56	**106.31**	**100.67**	**99.21**	**0.6%**	**0.4%**	**0.2%**	**0.2%**

Table D1. Key results for demand sector technology cases (continued)

Consumption, emissions, combined heat and power capacity and generation	2012	2020				2030			
		2013 Demand Technology	Reference	High Demand Technology	Best Available Demand Technology	2013 Demand Technology	Reference	High Demand Technology	Best Available Demand Technology
Carbon dioxide emissions (million metric tons)									
by sector									
Residential	295	308	302	288	271	300	286	263	231
Commercial	206	224	224	222	222	228	230	228	226
Industrial[5]	937	1,094	1,060	1,054	1,061	1,183	1,107	1,097	1,114
Transportation	1,812	1,779	1,777	1,759	1,775	1,672	1,677	1,644	1,681
Electric power[12]	2,039	2,174	2,112	2,000	1,892	2,318	2,227	2,031	1,911
by fuel									
Petroleum[17]	2,254	2,263	2,252	2,226	2,244	2,152	2,136	2,098	2,133
Natural gas	1,366	1,489	1,447	1,396	1,378	1,684	1,572	1,448	1,428
Coal	1,657	1,815	1,766	1,688	1,586	1,854	1,807	1,705	1,590
Other[18]	12	12	12	12	12	12	12	12	12
Total carbon dioxide emissions	**5,290**	**5,579**	**5,476**	**5,322**	**5,220**	**5,702**	**5,527**	**5,263**	**5,163**
Residential delivered energy intensity (million Btu per household)	91.5	90.5	88.1	82.8	77.5	86.4	81.5	73.0	65.3
Commercial delivered energy intensity (thousand Btu per square foot)	100.7	99.4	98.5	95.3	93.7	97.3	95.6	88.2	85.8
Industrial delivered energy intensity (thousand Btu per 2005 dollar)	3.84	3.57	3.48	3.46	3.48	3.29	3.11	3.06	3.09
Residential sector net summer capacity (megawatts)									
Natural gas	0	0	0	0	0	0	0	0	0
Solar photovoltaic	1,553	5,330	6,327	6,867	7,904	5,638	9,364	14,807	22,999
Wind	55	186	590	644	737	186	590	644	737
Residential sector 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	2.48	8.29	9.96	10.81	12.47	8.80	14.92	23.67	36.77
Wind	0.07	0.26	0.82	0.89	1.00	0.26	0.82	0.89	1.00
Commercial sector net summer capacity (megawatts)									
Natural gas	1,041	1,638	1,770	2,132	2,177	3,085	4,206	5,921	5,959
Solar photovoltaic	3,155	6,205	6,417	6,731	7,566	7,170	9,561	12,978	18,279
Wind	97	104	109	108	109	160	307	309	303
Commercial sector electricity generation (billion kilowatthours)									
Natural gas	7.57	11.91	12.87	15.50	15.83	22.43	30.59	43.07	43.35
Solar photovoltaic	4.86	9.53	9.94	10.46	11.80	11.07	15.16	20.63	28.99
Wind	0.12	0.13	0.14	0.14	0.14	0.22	0.43	0.43	0.43

[1]Includes propane, kerosene, and distillate fuel oil.
[2]Includes wood used for residential heating. Excludes nonmarketed renewable energy consumption for geothermal heat pumps, buildings photovoltaic systems, and solar thermal water heaters.
[3]Includes propane, motor gasoline (including ethanol and ethers), kerosene, distillate fuel oil, and residual fuel oil.
[4]Includes commercial sector consumption of wood and wood waste, landfill gas, municipal waste, and other biomass for combined heat and power. Excludes nonmarketed renewable energy consumption for geothermal heat pumps, buildings photovoltaic systems, and solar thermal water heaters.
[5]Includes energy for combined heat and power plants that have a non-regulatory status, and small on-site generating systems.
[6]Includes ethane, natural gasoline, and refinery olefins.
[7]Includes motor gasoline (including ethanol and ethers), residual fuel oil, petroleum coke, asphalt, road oil, lubricants, still gas, and miscellaneous petroleum products.
[8]Includes consumption of energy produced from hydroelectric, wood and wood waste, municipal waste, and other biomass sources. Excludes ethanol.
[9]Includes ethanol and ethers blended into gasoline.
[10]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.
[11]Includes propane, residual fuel oil, aviation gasoline, and lubricants.
[12]Includes consumption of energy by electricity-only and combined heat and power plants that have a regulatory status.
[13]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.
[14]Includes conventional hydroelectric, geothermal, wood and wood waste, biogenic municipal waste, other biomass, wind, photovoltaic, and solar thermal sources. Excludes net electricity imports.
[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 2012, international bunker fuels accounted for 90 to 126 million metric tons annually.
[18]Includes emissions from geothermal power and emissions from non-biogenic municipal waste.
Btu = British thermal unit.
- - = Not applicable.
Note: Totals may not equal sum of components due to independent rounding. Data for 2012 are model results and may differ from official EIA data reports.
Source: U.S. Energy Information Administration, AEO2014 National Energy Modeling System, runs FROZTECH.D121813A, REF2014.D102413A, HIGHTECH.D121813A, and BESTTECH.D121813A.

2040				Annual Growth 2012-2040 (percent)			
2013 Demand Technology	Reference	High Demand Technology	Best Available Demand Technology	2013 Demand Technology	Reference	High Demand Technology	Best Available Demand Technology
289	268	240	197	-0.1%	-0.4%	-0.7%	-1.4%
240	246	246	242	0.5%	0.6%	0.6%	0.6%
1,235	1,123	1,110	1,128	1.0%	0.6%	0.6%	0.7%
1,685	1,691	1,660	1,703	-0.3%	-0.2%	-0.3%	-0.2%
2,361	2,271	2,057	1,941	0.5%	0.4%	0.0%	-0.2%
2,145	2,113	2,090	2,113	-0.2%	-0.2%	-0.3%	-0.2%
1,811	1,694	1,523	1,512	1.0%	0.8%	0.4%	0.4%
1,842	1,780	1,687	1,576	0.4%	0.3%	0.1%	-0.2%
12	12	12	12	0.0%	0.0%	0.0%	0.0%
5,810	**5,599**	**5,313**	**5,213**	**0.3%**	**0.2%**	**0.0%**	**-0.1%**
83.3	76.5	67.4	57.7	-0.3%	-0.6%	-1.1%	-1.6%
97.9	93.9	84.8	82.0	-0.1%	-0.3%	-0.6%	-0.7%
2.98	2.75	2.71	2.73	-0.9%	-1.2%	-1.2%	-1.2%
1	1	1	1	- -	- -	- -	- -
6,283	14,366	27,180	47,373	5.1%	8.3%	10.8%	13.0%
186	610	667	794	4.4%	8.9%	9.3%	10.0%
0.00	0.00	0.00	0.00	- -	- -	- -	- -
9.82	23.12	43.67	75.94	5.0%	8.3%	10.8%	13.0%
0.26	0.85	0.92	1.09	4.6%	9.1%	9.4%	10.0%
5,691	9,752	14,094	13,792	6.3%	8.3%	9.7%	9.6%
9,341	15,094	23,123	33,742	4.0%	5.7%	7.4%	8.8%
396	814	944	1,114	5.2%	7.9%	8.5%	9.1%
41.40	70.94	102.53	100.33	6.3%	8.3%	9.7%	9.6%
14.54	24.33	36.99	53.91	4.0%	5.9%	7.5%	9.0%
0.56	1.16	1.34	1.57	5.6%	8.3%	8.9%	9.5%

Table D2. Key results for policy extension cases

Consumption, emissions, electricity generating capacity and generation, and prices	2012	2020			2030			2040		
		Reference	No Sunset	Extended Policies	Reference	No Sunset	Extended Policies	Reference	No Sunset	Extended Policies
Energy consumption (quadrillion Btu)										
Residential										
Liquid fuels and other petroleum[1]	1.02	0.89	0.88	0.89	0.75	0.75	0.75	0.66	0.66	0.65
Natural gas	4.26	4.56	4.52	4.54	4.43	4.34	4.24	4.21	4.07	3.89
Renewable energy[2]	0.45	0.46	0.46	0.46	0.44	0.44	0.44	0.42	0.41	0.41
Electricity	4.69	4.84	4.79	4.79	5.21	5.02	4.80	5.65	5.36	4.96
Total residential	**10.42**	**10.74**	**10.65**	**10.67**	**10.83**	**10.55**	**10.22**	**10.94**	**10.50**	**9.91**
Commercial										
Liquid fuels and other petroleum[3]	0.63	0.68	0.68	0.68	0.67	0.67	0.67	0.68	0.68	0.67
Natural gas	2.96	3.23	3.23	3.22	3.35	3.38	3.35	3.65	3.72	3.65
Coal	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04
Renewable energy[4]	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13
Electricity	4.52	4.69	4.69	4.68	5.18	5.16	5.10	5.72	5.69	5.62
Total commercial	**8.29**	**8.78**	**8.78**	**8.76**	**9.38**	**9.39**	**9.29**	**10.22**	**10.27**	**10.11**
Industrial[5]										
Liquid fuels and other petroleum[6]	8.06	9.56	9.56	9.55	10.10	10.13	10.06	10.10	10.15	9.94
Natural gas	8.75	10.04	10.03	10.05	10.87	10.94	10.93	11.28	11.42	11.36
Coal	1.48	1.57	1.56	1.56	1.52	1.53	1.53	1.44	1.46	1.46
Renewable energy[7]	2.00	2.50	2.50	2.49	2.79	2.81	2.80	3.07	3.08	3.07
Electricity	3.35	4.04	4.04	4.03	4.33	4.35	4.35	4.34	4.38	4.37
Total industrial	**23.63**	**27.71**	**27.68**	**27.68**	**29.62**	**29.76**	**29.68**	**30.22**	**30.49**	**30.19**
Transportation										
Liquid fuels and other petroleum[8]	25.93	25.55	25.54	25.51	23.94	23.96	23.56	23.73	23.80	22.33
Pipeline fuel natural gas	0.73	0.74	0.74	0.75	0.82	0.81	0.80	0.85	0.80	0.80
Compressed / liquefied natural gas	0.04	0.08	0.08	0.08	0.28	0.28	0.26	0.86	0.91	0.94
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	0.06	0.06	0.12
Total transportation	**26.72**	**26.40**	**26.40**	**26.37**	**25.08**	**25.10**	**24.68**	**25.50**	**25.58**	**24.19**
Electric power[9]										
Distillate and residual fuel oil	0.23	0.18	0.18	0.18	0.18	0.18	0.18	0.19	0.18	0.18
Natural gas	9.46	9.00	9.26	9.26	10.28	9.76	9.54	11.48	9.11	8.88
Steam coal	15.82	16.95	16.77	16.75	17.44	17.23	17.10	17.27	17.13	16.99
Nuclear / uranium[10]	8.05	8.15	8.15	8.15	8.18	8.15	8.15	8.49	8.15	8.15
Renewable energy[11]	4.59	6.08	5.73	5.71	6.68	7.21	6.86	7.44	10.62	9.81
Non-biogenic municipal waste	0.23	0.23	0.23	0.23	0.23	0.23	0.23	0.23	0.23	0.23
Net electricity imports	0.16	0.11	0.11	0.11	0.12	0.11	0.10	0.12	0.11	0.10
Total electric power	**38.53**	**40.70**	**40.43**	**40.37**	**43.12**	**42.88**	**42.15**	**45.20**	**45.53**	**44.34**
Total energy consumption										
Liquid fuels and other petroleum	35.87	36.86	36.84	36.80	35.65	35.70	35.21	35.35	35.47	33.76
Natural gas	26.20	27.65	27.87	27.89	30.03	29.52	29.12	32.32	30.03	29.51
Steam coal	17.34	18.56	18.38	18.35	19.01	18.81	18.67	18.75	18.63	18.49
Nuclear / uranium[10]	8.05	8.15	8.15	8.15	8.18	8.15	8.15	8.49	8.15	8.15
Renewable energy[12]	7.17	9.17	8.81	8.79	10.05	10.59	10.23	11.05	14.25	13.42
Other[13]	0.39	0.34	0.34	0.34	0.35	0.34	0.33	0.35	0.34	0.33
Total energy consumption	**95.02**	**100.73**	**100.39**	**100.32**	**103.27**	**103.11**	**101.72**	**106.31**	**106.88**	**103.67**
Carbon dioxide emissions (million metric tons)										
by sector										
Residential	295	302	300	301	286	281	275	268	260	250
Commercial	206	224	224	223	230	231	229	246	250	245
Industrial[5]	937	1,060	1,059	1,060	1,107	1,113	1,108	1,123	1,134	1,116
Transportation	1,812	1,777	1,776	1,775	1,677	1,676	1,648	1,691	1,694	1,595
Electric power[9]	2,039	2,112	2,109	2,106	2,227	2,179	2,155	2,271	2,132	2,107
by fuel										
Petroleum[14]	2,254	2,252	2,249	2,249	2,136	2,135	2,104	2,113	2,117	2,001
Natural gas	1,366	1,447	1,459	1,460	1,572	1,545	1,524	1,694	1,573	1,545
Coal	1,657	1,766	1,748	1,746	1,807	1,788	1,775	1,780	1,768	1,755
Other[15]	12	12	12	12	12	12	12	12	12	12
Total carbon dioxide emissions	**5,290**	**5,476**	**5,468**	**5,466**	**5,527**	**5,480**	**5,415**	**5,599**	**5,469**	**5,313**

Table D2. Key results for policy extension cases (continued)

Consumption, emissions, electricity generating capacity and generation, and prices	2012	2020			2030			2040		
		Reference	No Sunset	Extended Policies	Reference	No Sunset	Extended Policies	Reference	No Sunset	Extended Policies
Electricity generating capacity (gigawatts)	**1,066**	**1,069**	**1,056**	**1,053**	**1,168**	**1,184**	**1,156**	**1,316**	**1,414**	**1,350**
Electric power sector[9]	1,032	1,022	1,000	996	1,105	1,084	1,055	1,228	1,262	1,198
Coal	307	259	255	253	258	254	252	258	254	252
Oil and natural gas steam	100	86	84	82	72	70	65	70	67	62
Combined-cycle	212	231	231	233	286	262	261	342	287	281
Combustion turbine / diesel	140	150	148	147	184	173	164	224	208	186
Nuclear / uranium	102	98	98	98	98	98	98	102	98	98
Pumped storage	22	22	22	22	22	22	22	22	22	22
Renewable sources	149	174	161	161	180	203	191	201	321	292
of which: Solar	3	10	9	9	10	19	17	19	66	58
of which: Wind	59	76	62	62	76	90	80	85	159	138
Distributed generation	0	2	1	1	5	3	2	9	5	4
Residential and commercial sectors	7	16	25	25	25	60	60	41	103	103
of which: Natural gas	1	2	2	2	4	5	4	10	10	10
of which: Solar photovoltaic	5	13	21	21	19	49	49	29	81	81
of which: Wind	0	1	1	2	1	5	5	1	11	11
Industrial sector[5]	27	31	32	32	39	40	41	46	49	49
of which: Natural gas	15	17	18	18	23	25	25	29	32	32
Cumulative capacity additions (gigawatts)	**0**	**87**	**80**	**81**	**201**	**224**	**203**	**351**	**458**	**401**
Cumulative capacity retirements (gigawatts)	**0**	**78**	**85**	**89**	**94**	**101**	**108**	**97**	**105**	**111**
Generation by fuel (billion kilowatthours)	**4,054**	**4,402**	**4,400**	**4,399**	**4,815**	**4,819**	**4,742**	**5,219**	**5,243**	**5,116**
Electric power sector[9]	3,890	4,193	4,175	4,173	4,540	4,479	4,400	4,844	4,753	4,628
Coal	1,499	1,632	1,616	1,614	1,678	1,660	1,647	1,661	1,649	1,637
Petroleum	20	16	16	16	16	16	16	16	16	16
Natural gas	1,133	1,155	1,189	1,191	1,391	1,296	1,266	1,605	1,231	1,199
Nuclear / uranium	769	779	779	779	782	779	779	811	779	779
Pumped storage / other	6	3	3	3	3	3	3	3	3	3
Renewable sources	463	607	571	569	668	723	687	743	1,072	992
of which: Wood and other biomass	11	37	43	42	68	60	59	72	64	65
of which: Solar	4	18	17	17	20	40	35	39	147	129
of which: Wind	142	218	172	172	219	258	229	248	480	417
Distributed generation	0	1	1	1	2	2	2	4	3	2
Residential and commercial sectors	20	38	53	53	66	123	123	125	225	222
of which: Natural gas	8	13	13	13	31	33	33	71	75	73
of which: Solar photovoltaic	7	20	33	33	30	79	79	47	129	129
of which: Wind	0	1	2	2	1	7	7	2	15	15
Industrial sector[5]	145	171	172	173	209	216	218	251	265	266
of which: Natural gas	88	99	101	102	128	135	137	160	174	175
Delivered natural gas prices (2012 dollars per thousand cubic feet)										
Residential	10.69	11.85	11.89	11.98	13.80	13.65	13.62	16.33	15.62	15.77
Commercial	8.29	9.70	9.73	9.83	11.44	11.25	11.11	13.37	12.65	12.56
Industrial[5]	3.85	5.92	5.94	6.06	7.14	6.96	6.81	8.78	8.28	8.23
Electric power[9]	3.51	5.19	5.21	5.32	6.64	6.43	6.27	8.34	7.70	7.65
Average electricity price (2012 cents per kilowatthour)	9.8	10.1	10.1	10.1	10.4	10.3	10.2	11.1	10.7	10.6

[1]Includes propane, kerosene, and distillate fuel oil.
[2]Includes wood used for residential heating. Excludes nonmarketed renewable energy consumption for geothermal heat pumps, buildings photovoltaic systems, and solar thermal water heaters.
[3]Includes propane, motor gasoline (including ethanol and ethers), kerosene, distillate fuel oil, and residual fuel oil.
[4]Includes commercial sector consumption of wood and wood waste, landfill gas, municipal waste, and other biomass for combined heat and power. Excludes nonmarketed renewable energy consumption for geothermal heat pumps, buildings photovoltaic systems, and solar thermal water heaters.
[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 and ethers), 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]Includes propane, motor gasoline, ethanol and ethers, jet fuel, distillate fuel oil, residual fuel oil, aviation gasoline, and lubricants.
[9]Includes consumption of energy by electricity-only and combined heat and power plants that have a regulatory status.
[10]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.
[11]Includes conventional hydroelectric, geothermal, wood and wood waste, biogenic municipal waste, other biomass, wind, photovoltaic, and solar thermal sources.
[12]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.
[13]Includes non-biogenic municipal waste, liquid hydrogen, and net electricity imports.
[14]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 2012, international bunker fuels accounted for 90 to 126 million metric tons annually.
[15]Includes emissions from geothermal power and emissions from non-biogenic municipal waste.
Btu = British thermal unit.
- - = Not applicable.
Note: Totals may not equal sum of components due to independent rounding. Data for 2012 are model results and may differ from official EIA data reports.
Source: U.S. Energy Information Administration, AEO2014 National Energy Modeling System, runs REF2014.D102413A, NOSUNSET.D121713A, and EXTENDED.D022814A.

Table D3. Key results for accelerated power plant retirement and nuclear plant cases
(gigawatts, unless otherwise noted)

Net summer capacity, generation, emissions, and fuel prices	2012	2040					
		High Nuclear	Reference	Accelerated Coal Retirements	Accelerated Nuclear Retirements	Accelerated Coal and Nuclear Retirements	Low Nuclear
Capacity							
Coal steam	306.6	258.3	258.4	198.8	260.0	204.7	239.1
Oil and natural gas steam	100.4	70.5	69.6	65.3	67.4	64.7	75.2
Combined cycle	211.9	331.5	342.2	383.9	373.7	406.9	406.1
Combustion turbine / diesel	139.8	221.9	223.7	221.1	223.5	220.7	229.4
Nuclear / uranium	102.1	119.7	102.0	104.1	60.4	60.4	25.2
Pumped storage	22.4	22.4	22.4	22.4	22.4	22.4	22.4
Fuel cells	0.0	0.1	0.1	0.1	0.1	0.1	0.1
Renewable sources	148.9	199.4	200.5	202.1	213.9	211.6	200.8
Distributed generation	0.0	9.1	8.9	6.0	8.9	5.5	12.6
Combined heat and power[1]	33.8	86.4	87.7	95.3	89.8	97.5	152.5
Total	**1,065.8**	**1,319.4**	**1,315.6**	**1,299.1**	**1,319.8**	**1,294.4**	**1,363.3**
Cumulative additions							
Coal steam	0.0	2.6	2.6	2.5	4.2	2.5	2.5
Oil and natural gas steam	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Combined cycle	0.0	119.9	130.6	172.3	162.1	195.3	194.5
Combustion turbine / diesel	0.0	91.4	93.2	90.8	93.1	90.6	99.0
Nuclear / uranium	0.0	16.4	9.7	11.8	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	0.0	51.4	52.5	54.1	65.8	63.5	52.8
Distributed generation	0.0	9.1	8.9	6.0	8.9	5.5	12.6
Combined heat and power[1]	0.0	52.6	53.9	61.5	56.0	63.8	118.7
Total	**0.0**	**343.5**	**351.5**	**399.1**	**395.8**	**426.8**	**485.6**
Cumulative retirements	**0.0**	**95.9**	**96.7**	**160.8**	**136.8**	**193.2**	**183.2**
Generation by fuel (billion kilowatthours)							
Coal	1,499	1,659	1,661	1,118	1,672	1,178	1,504
Petroleum	20	16	16	14	16	15	16
Natural gas	1,133	1,493	1,605	1,922	1,834	2,114	2,413
Nuclear / uranium	769	951	811	827	483	483	201
Pumped storage / other	6	3	3	3	3	3	3
Renewable sources	463	739	743	820	782	849	727
Distributed generation	0	4	4	3	5	3	34
Combined heat and power[1]	165	371	375	404	383	412	505
Total	**4,054**	**5,238**	**5,219**	**5,111**	**5,178**	**5,056**	**5,404**
Carbon dioxide emissions by the electric power sector (million metric tons)[2]							
Petroleum	19	14	14	13	14	13	14
Natural gas	494	570	608	714	684	780	914
Coal	1,514	1,635	1,637	1,082	1,646	1,142	1,479
Other[3]	12	12	12	12	12	12	12
Total	**2,039**	**2,231**	**2,271**	**1,821**	**2,356**	**1,946**	**2,418**
Prices to the electric power sector[2] (2012 dollars per million Btu)							
Petroleum	21.46	24.25	24.30	23.83	24.29	23.91	21.23
Natural gas	3.44	7.87	8.16	8.60	8.57	9.03	5.43
Coal	2.39	3.18	3.19	5.14	3.20	5.20	3.01
Average electricity price (2012 cents per kilowatthour)	**9.8**	**11.0**	**11.1**	**12.0**	**11.5**	**12.5**	**9.9**

[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 2012 are model results and may differ from official EIA data reports.
Source: U.S. Energy Information Administration, AEO2014 National Energy Modeling System runs HINUC14.D120313A, REF2014.D102413A, HCCSTOM.D012314A, LOWNUC14.D012314B, HCLONUC.D012314A, and ALTLOWNUC14.D012314C.

Table D4. Key results for renewable technology case

Capacity, generation, and emissions	2012	2020		2030		2040	
		Reference	Low Renewable Technology Cost	Reference	Low Renewable Technology Cost	Reference	Low Renewable Technology Cost
Net summer capacity (gigawatts)							
Electric power sector[1]							
Conventional hydropower	78.10	78.41	79.55	79.75	80.50	80.35	82.00
Geothermal[2]	2.58	4.02	4.28	6.58	6.66	8.80	9.07
Municipal waste[3]	3.57	3.63	3.63	3.63	3.63	3.63	3.63
Wood and other biomass[4]	2.70	3.14	3.14	3.14	3.26	3.46	4.56
Solar thermal	0.48	1.73	1.73	1.73	1.73	1.73	1.73
Solar photovoltaic[5]	2.49	7.90	14.63	8.62	20.83	17.07	56.34
Wind	59.01	75.59	77.27	76.12	82.63	85.48	119.92
Total	**148.92**	**174.43**	**184.23**	**179.56**	**199.24**	**200.52**	**277.26**
End-use sector[6]							
Conventional hydropower	0.29	0.29	0.29	0.29	0.29	0.29	0.29
Geothermal	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Municipal waste[7]	0.47	0.47	0.47	0.47	0.47	0.47	0.47
Wood and other biomass	4.89	6.27	6.92	7.95	9.86	9.62	13.35
Solar photovoltaic[5]	4.71	12.75	13.89	18.93	25.65	29.47	43.27
Wind	0.15	0.70	1.21	0.90	1.70	1.42	3.38
Total	**10.51**	**20.48**	**22.77**	**28.53**	**37.97**	**41.26**	**60.75**
Generation (billion kilowatthours)							
Electric power sector[1]							
Coal	1,499	1,632	1,602	1,678	1,656	1,661	1,644
Petroleum	20	16	16	16	16	16	17
Natural gas	1,133	1,155	1,132	1,391	1,337	1,605	1,405
Total fossil	**2,651**	**2,803**	**2,750**	**3,085**	**3,009**	**3,282**	**3,066**
Conventional hydropower	273.89	287.67	293.48	294.35	297.83	297.34	303.30
Geothermal	15.56	28.24	30.34	49.04	49.86	67.26	69.62
Municipal waste[8]	16.79	19.05	18.67	18.15	18.53	19.21	19.12
Wood and other biomass[4]	11.04	36.71	63.30	67.50	85.07	72.22	93.42
Dedicated plants	9.84	15.31	15.86	16.17	17.43	18.99	27.03
Cofiring	1.20	21.40	47.44	51.33	67.64	53.23	66.39
Solar thermal	0.90	3.52	3.52	3.53	3.53	3.53	3.53
Solar photovoltaic[5]	3.25	14.54	30.06	16.07	44.82	35.24	128.36
Wind	141.87	217.53	223.15	219.06	237.99	248.02	354.74
Total renewable	**463.29**	**607.26**	**662.52**	**667.71**	**737.62**	**742.82**	**972.09**
End-use sector[6]							
Total fossil	**112**	**128**	**128**	**175**	**173**	**247**	**247**
Conventional hydropower	1.38	1.38	1.38	1.38	1.38	1.38	1.38
Geothermal	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Municipal waste[7]	3.65	3.63	3.63	3.63	3.63	3.63	3.63
Wood and other biomass	26.53	34.10	37.75	43.75	54.79	53.50	75.17
Solar photovoltaic[5]	7.35	19.91	21.75	30.09	40.94	47.46	69.49
Wind	0.20	0.96	1.62	1.25	2.33	2.01	4.67
Total renewable	**39.11**	**59.98**	**66.13**	**80.10**	**103.07**	**107.99**	**154.34**

Table D4. Key results for renewable technology case (continued)

Capacity, generation, and emissions	2012	2020		2030		2040	
		Reference	Low Renewable Technology Cost	Reference	Low Renewable Technology Cost	Reference	Low Renewable Technology Cost
Carbon dioxide emissions by the electric power sector (million metric tons)[1]							
Coal	1,514	1,609	1,580	1,656	1,634	1,637	1,621
Petroleum	19	13	13	14	14	14	14
Natural gas	494	478	469	545	530	608	541
Other [9]	12	12	12	12	12	12	12
Total	**2,039**	**2,112**	**2,073**	**2,227**	**2,189**	**2,271**	**2,188**

[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]Does not include off-grid photovoltaics (PV). Based on annual PV shipments from 1989 through 2012, EIA estimates that as much as 274 megawatts of remote electricity generation PV applications (i.e., off-grid power systems) were in service in 2012, plus an additional 573 megawatts in communications, transportation, and assorted other non-grid-connected, specialized applications. See U.S. Energy Information Administration, *Annual Energy Review 2011*, DOE/EIA-0384(2011) (Washington, DC, September 2012), Table 10.9 (annual PV shipments, 1989-2010), and Table 12 (U.S. photovoltaic module shipments by end use, sector, and type) in U.S. Energy Information Administration, *Solar Photovoltaic Cell/Module Shipments Report, 2011* (Washington, DC, September 2012) and U.S. Energy Information Administration, *Solar Photovoltaic Cell/Module Shipments Report, 2012* (Washington, DC, December 2013). 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 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.
[7]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.
[8]Includes biogenic municipal waste, landfill gas, and municipal sewage sludge. Incremental growth is assumed to be for landfill gas facilities. Only biogenic municipal waste is included. The U.S. Energy Information Administration estimates that in 2012 approximately 7 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).
[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 2012 are model results and may differ from official EIA data reports.
Source: U.S. Energy Information Administration, AEO2014 National Energy Modeling System runs REF2014.D102413A, and LCR_2014.D120613A.

Table D5. Key results for enviornmental cases

Net summer capacity, generation, emissions, fuel prices, and coal production	2012	2030					2040				
		Reference	GHG10	GHG25	High Oil and Gas Resource	GHG10 and Low Gas Prices	Reference	GHG10	GHG25	High Oil and Gas Resource	GHG10 and Low Gas Prices
Capacity (gigawatts)											
Coal steam	306.6	258.4	208.4	52.6	243.8	163.2	258.4	176.7	19.1	243.8	127.4
Oil and natural gas steam	100.4	72.1	64.8	42.4	81.2	65.9	69.6	55.2	31.2	79.8	60.4
Combined cycle	211.9	285.6	313.4	381.6	294.4	372.6	342.2	365.4	420.7	382.3	477.5
Combustion turbine / diesel	139.8	184.0	178.8	185.8	202.4	191.1	223.7	206.1	179.4	241.2	218.4
Nuclear / uranium	102.1	98.2	101.3	142.1	97.8	97.8	102.0	141.8	231.6	97.8	111.0
Pumped storage	22.4	22.4	22.4	22.4	22.4	22.4	22.4	22.4	22.4	22.4	22.4
Renewable sources	148.9	179.6	200.5	312.6	170.1	183.5	200.5	279.8	363.1	177.4	227.5
Distributed generation	0.0	4.6	1.5	0.3	7.6	2.4	8.9	2.9	0.3	17.8	4.8
Combined heat and power[1]	33.8	63.4	67.1	75.5	64.0	67.6	87.7	96.4	109.3	86.9	95.2
Total	**1,065.8**	**1,168.2**	**1,158.4**	**1,215.2**	**1,183.7**	**1,166.5**	**1,315.6**	**1,346.6**	**1,377.3**	**1,349.5**	**1,344.4**
Cumulative additions (gigawatts)											
Coal steam	0.0	2.5	2.5	2.5	2.5	2.5	2.6	2.5	2.5	2.5	2.5
Combined cycle	0.0	74.0	101.8	170.0	82.8	160.9	130.6	153.8	209.1	170.7	265.9
Combustion turbine / diesel	0.0	53.0	48.3	59.8	70.7	60.1	93.2	77.2	75.2	110.0	88.2
Nuclear / uranium	0.0	5.8	9.0	49.8	5.5	5.5	9.7	49.4	139.3	5.5	18.7
Renewable sources	0.0	31.6	52.5	164.6	22.1	35.5	52.5	131.8	215.1	29.4	79.5
Distributed generation	0.0	4.6	1.5	0.3	7.6	2.4	8.9	2.9	0.3	17.8	4.8
Combined heat and power[1]	0.0	29.7	33.4	41.7	30.2	33.8	53.9	62.6	75.6	53.2	61.4
Total	**0.0**	**201.1**	**249.0**	**488.6**	**221.4**	**300.8**	**351.5**	**480.2**	**717.2**	**389.1**	**520.9**
Cumulative retirements (gigawatts)	**0.0**	**93.8**	**151.4**	**334.1**	**98.5**	**195.2**	**96.7**	**194.5**	**400.6**	**100.4**	**237.3**
Generation by fuel (billion kilowatthours)											
Coal	1,499	1,678	1,255	241	1,544	834	1,661	964	48	1,445	460
Petroleum	20	16	15	10	16	13	16	14	9	16	12
Natural gas	1,133	1,391	1,531	1,780	1,647	2,148	1,605	1,489	1,405	2,108	2,623
Nuclear / uranium	769	782	802	1,114	779	779	811	1,116	1,819	779	879
Pumped storage / other	6	3	3	3	3	3	3	3	3	3	3
Renewable sources	463	668	794	1,044	631	717	743	1,074	1,185	672	847
Distributed generation	0	2	1	0	22	1	4	1	0	48	2
Combined heat and power[1]	165	276	287	313	283	295	375	400	432	385	411
Total	**4,054**	**4,815**	**4,689**	**4,505**	**4,924**	**4,791**	**5,219**	**5,060**	**4,902**	**5,456**	**5,237**
Retrofits (gigawatts)											
Scrubber	0.00	31.99	23.25	22.94	28.71	23.03	31.99	23.25	22.94	28.71	23.03
Nitrogen oxide controls											
Combustion	0.00	0.78	0.78	0.78	0.78	0.78	0.78	0.78	0.78	0.78	0.78
Selective catalytic reduction post-combustion	0.00	10.33	11.11	11.71	10.29	10.25	10.33	11.97	11.71	10.29	10.68
Selective non-catalytic reduction post-combustion	0.00	3.04	3.04	3.04	3.04	3.04	3.04	4.49	3.04	3.04	3.78
Emissions by the electric power sector[2]											
Sulfur dioxide (million short tons)	3.34	1.58	1.09	0.24	1.37	0.67	1.61	0.84	0.03	1.32	0.38
Nitrogen oxides (million short tons)	1.68	1.59	1.16	0.37	1.44	0.78	1.60	0.94	0.24	1.39	0.55
Mercury (short tons)	26.35	6.69	4.90	1.15	6.07	3.24	6.81	3.90	0.28	5.91	1.90
Carbon dioxide emissions (million metric tons)											
by sector											
Residential	295	286	282	277	291	288	268	264	257	277	271
Commercial	206	230	224	219	239	234	246	240	233	263	254
Industrial[3]	937	1,107	1,086	1,073	1,151	1,121	1,123	1,102	1,078	1,206	1,171
Transportation	1,812	1,677	1,647	1,606	1,723	1,686	1,691	1,651	1,604	1,767	1,714
Electric power[2]	2,039	2,227	1,810	826	2,201	1,620	2,271	1,446	419	2,254	1,372
by fuel											
Petroleum[4]	2,254	2,136	2,094	2,040	2,192	2,141	2,113	2,060	2,000	2,208	2,143
Natural gas	1,366	1,572	1,589	1,592	1,730	1,851	1,694	1,595	1,412	1,981	2,066
Coal	1,657	1,807	1,354	358	1,671	944	1,780	1,036	168	1,565	562
Other[5]	12	12	12	12	12	12	12	12	12	12	12
Total carbon dioxide emissions	**5,290**	**5,527**	**5,049**	**4,001**	**5,605**	**4,949**	**5,599**	**4,703**	**3,591**	**5,767**	**4,782**

Table D5. Key results for enviornmental cases (continued)

Net summer capacity, generation, emissions, fuel prices, and coal production	2012	2030					2040				
		Reference	GHG10	GHG25	High Oil and Gas Resource	GHG10 and Low Gas Prices	Reference	GHG10	GHG25	High Oil and Gas Resource	GHG10 and Low Gas Prices
Energy consumption (quadrillion Btu)											
Liquid fuels and other petroleum[6]	35.87	35.65	35.01	34.28	36.59	35.87	35.35	34.57	33.72	37.20	36.16
Natural gas	26.20	30.03	30.56	31.99	33.02	35.53	32.32	31.07	30.36	37.86	39.93
Coal[7]	17.34	19.01	14.50	3.95	17.57	10.07	18.75	11.41	1.96	16.49	6.15
Nuclear / uranium[8]	8.05	8.18	8.40	11.66	8.15	8.15	8.49	11.68	19.03	8.15	9.20
Hydropower	2.67	2.87	2.91	2.93	2.83	2.87	2.90	2.98	2.95	2.84	2.94
Biomass[9]	2.53	3.95	4.61	4.13	3.96	4.32	4.26	5.29	4.33	4.37	4.53
Other renewable energy[10]	1.97	3.23	3.76	6.69	2.91	3.32	3.89	6.03	8.15	3.21	4.62
Other[11]	0.39	0.35	0.35	0.42	0.33	0.34	0.35	0.36	0.45	0.30	0.32
Total consumption	**95.02**	**103.27**	**100.10**	**96.05**	**105.37**	**100.47**	**106.31**	**103.40**	**100.95**	**110.43**	**103.85**
Prices to the electric power sector[2] (2012 dollars per million Btu)											
Natural gas	3.44	6.49	7.70	9.34	5.02	6.07	8.16	9.57	12.38	5.17	7.31
Coal	2.39	2.93	4.74	7.14	2.78	4.45	3.19	6.08	10.27	2.97	5.62
Average energy prices to all users (2012 dollars per million Btu)											
Propane	23.24	24.66	26.03	27.85	22.48	23.99	26.79	28.59	31.75	24.04	26.10
E85[12]	35.06	27.91	28.85	30.40	26.18	26.72	35.49	35.93	37.64	33.33	33.92
Motor gasoline[13]	30.44	28.53	29.95	32.02	26.09	27.32	32.67	34.65	37.85	29.18	30.82
Jet fuel[14]	22.99	23.71	25.09	27.10	20.82	22.07	28.07	30.28	33.46	24.10	26.52
Distillate fuel oil	28.36	29.67	31.06	33.10	27.15	28.40	33.54	35.61	38.90	30.19	32.20
Residual fuel oil	20.41	16.32	17.79	19.83	14.79	16.07	19.42	21.81	25.28	17.18	19.54
Natural gas	5.38	8.49	9.62	11.07	6.88	7.65	10.38	11.86	14.65	7.06	8.92
Metallurgical coal	7.25	9.51	11.60	14.45	9.42	11.49	10.20	13.52	18.91	10.05	13.35
Other coal	2.44	2.98	4.82	7.46	2.85	4.56	3.25	6.18	11.26	3.04	5.84
Electricity	28.85	30.56	33.64	38.27	28.56	31.42	32.63	36.54	39.72	28.40	32.93
Average electricity price (2012 cents per kilowatthour)	**9.8**	**10.4**	**11.5**	**13.1**	**9.7**	**10.7**	**11.1**	**12.5**	**13.6**	**9.7**	**11.2**

[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.
[3]Includes combined heat and power plants that have a non-regulatory status, and small on-site generating systems.
[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 2012, international bunker fuels accounted for 90 to 126 million metric tons annually.
[5]Includes emissions from geothermal power and emissions from non-biogenic municipal waste.
[6]Estimated consumption. 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.
[7]Excludes coal converted to coal-based synthetic liquids and natural gas.
[8]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.
[9]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.
[10]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.
[11]Includes non-biogenic municipal waste, liquid hydrogen, and net electricity imports.
[12]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.
[13]Sales weighted-average price for all grades. Includes Federal, State and local taxes.
[14]Kerosene-type jet fuel. Includes Federal and State taxes while excluding county and local taxes.
GHG = Greenhouse gas.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Data for 2012 are model results and may differ from official EIA data reports.
Source: U.S. Energy Information Administration, AEO2014 National Energy Modeling System runs REF2014.D102413A, CO2FEE10.D011614A, CO2FEE25.D011614A, HIGHRESOURCE.D112913B, CO2FEE10HR.D011614A.

Table D6. Key results for low electricity demand case
(gigawatts, unless otherwise noted)

Net summer capacity, generation, emissions, and fuel prices	2012	2020		2030		2040	
		Reference	Low Electricity Demand	Reference	Low Electricity Demand	Reference	Low Electricity Demand
Total electricity sales (billion kilowatthours)	**3,686**	**3,986**	**3,580**	**4,327**	**3,604**	**4,623**	**3,690**
Average electricity price (2012 cents per kilowatthour)	**9.8**	**10.1**	**9.9**	**10.4**	**9.9**	**11.1**	**10.1**
Capacity							
Coal steam	306.6	259.2	199.9	258.4	199.6	258.4	199.6
Oil and natural gas steam	100.4	86.0	65.8	72.1	37.9	69.6	32.5
Combined cycle	211.9	231.0	229.4	285.6	230.6	342.2	242.1
Combustion turbine / diesel	139.8	149.7	133.8	184.0	119.6	223.7	120.8
Nuclear / uranium	102.1	97.8	97.8	98.2	97.8	102.0	97.8
Pumped storage	22.4	22.4	22.4	22.4	22.4	22.4	22.4
Fuel cells	0.0	0.1	0.1	0.1	0.1	0.1	0.1
Renewable sources	148.9	174.4	159.4	179.6	162.5	200.5	166.7
Distributed generation	0.0	1.6	0.2	4.6	0.2	8.9	0.5
Combined heat and power[1]	33.8	47.2	50.1	63.4	84.6	87.7	137.2
Total	**1,065.8**	**1,069.5**	**958.7**	**1,168.2**	**955.2**	**1,315.6**	**1,019.7**
Cumulative additions							
Coal steam	0.0	2.5	2.5	2.5	2.5	2.6	2.5
Oil and natural gas steam	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Combined cycle	0.0	19.4	17.8	74.0	19.0	130.6	30.5
Combustion turbine / diesel	0.0	17.8	7.4	53.0	8.1	93.2	12.5
Nuclear / uranium	0.0	5.5	5.5	5.8	5.5	9.7	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	0.0	26.4	11.4	31.6	14.5	52.5	18.7
Distributed generation	0.0	1.6	0.2	4.6	0.2	8.9	0.5
Combined heat and power[1]	0.0	13.5	16.3	29.7	50.8	53.9	103.4
Total	**0.0**	**86.7**	**61.0**	**201.1**	**100.6**	**351.5**	**173.6**
Cumulative retirements	**0.0**	**78.0**	**163.2**	**93.8**	**206.3**	**96.7**	**214.7**
Generation by fuel (billion kilowatthours)							
Coal	1,499	1,632	1,322	1,678	1,335	1,661	1,318
Petroleum	20	16	14	16	13	16	14
Natural gas	1,133	1,155	1,096	1,391	1,076	1,605	1,138
Nuclear / uranium	769	779	779	782	779	811	779
Pumped storage / other	6	3	3	3	3	3	3
Renewable sources	463	607	546	668	577	743	612
Distributed generation	0	1	0	2	0	4	0
Total electric power sector generation[2]	**3,890**	**4,193**	**3,760**	**4,540**	**3,783**	**4,844**	**3,865**
Combined heat and power[1]	165	209	215	276	309	375	457
Total electricity generation	**4,054**	**4,402**	**3,974**	**4,815**	**4,092**	**5,219**	**4,321**
Carbon dioxide emissions by the electric power sector (million metric tons)[2]							
Petroleum	19	13	12	14	12	14	12
Natural gas	494	478	453	545	438	608	456
Coal	1,514	1,609	1,296	1,656	1,308	1,637	1,292
Other[3]	12	12	12	12	12	12	12
Total	**2,039**	**2,112**	**1,772**	**2,227**	**1,770**	**2,271**	**1,771**
Prices to the electric power sector[2] (2012 dollars per million Btu)							
Petroleum	21.46	17.28	17.08	20.80	20.69	24.30	24.06
Natural gas	3.44	5.07	5.02	6.49	5.95	8.16	7.33
Coal	2.39	2.61	2.43	2.93	2.69	3.19	2.93

[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 2012 are model results and may differ from official EIA data reports.
Source: U.S. Energy Information Administration, AEO2014 National Energy Modeling System runs REF2014.D102413A, and FLAT.D010914A.

Table D7. Natural gas supply and disposition, oil and gas resource cases
(trillion cubic feet per year, unless otherwise noted)

Supply, disposition, and prices	2012	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										
(2012 dollars per million Btu)	2.75	5.28	4.38	4.34	8.15	6.03	4.25	10.53	7.65	4.58
(2012 dollars per thousand cubic feet)	2.81	5.39	4.47	4.44	8.33	6.17	4.35	10.76	7.82	4.68
Dry gas production[1]	**24.06**	**26.77**	**29.09**	**31.29**	**28.99**	**34.43**	**39.07**	**28.07**	**37.54**	**45.51**
Lower 48 onshore	22.07	24.30	26.65	28.61	25.28	30.82	36.29	23.59	33.43	42.41
Associated-dissolved[2]	2.06	2.47	2.65	3.09	2.04	2.25	3.43	1.69	1.91	2.99
Non-associated	20.02	21.83	24.00	25.52	23.25	28.57	32.86	21.89	31.52	39.42
Tight gas	4.86	5.99	6.48	6.54	6.31	8.06	7.62	6.55	8.41	9.51
Shale gas	9.72	11.53	13.33	14.79	13.10	16.92	21.85	11.59	19.82	26.95
Coalbed methane	1.58	1.73	1.66	1.59	1.86	1.61	1.43	2.15	1.71	1.40
Other	3.86	2.57	2.53	2.60	1.97	1.98	1.96	1.59	1.58	1.56
Lower 48 offshore	1.66	2.19	2.16	2.40	2.53	2.42	2.52	3.32	2.95	2.81
Associated-dissolved[2]	0.48	0.68	0.68	0.77	0.61	0.58	0.60	0.78	0.71	0.69
Non-associated	1.18	1.51	1.48	1.64	1.92	1.84	1.92	2.53	2.24	2.13
Alaska	0.33	0.28	0.28	0.28	1.18	1.19	0.27	1.17	1.17	0.28
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	**1.51**	**-0.99**	**-1.93**	**-2.18**	**-2.66**	**-4.94**	**-6.66**	**-2.21**	**-5.80**	**-8.30**
Pipeline[4]	1.37	0.18	0.00	0.15	-0.69	-1.57	-1.69	-0.35	-2.43	-3.33
Liquefied natural gas	0.15	-1.17	-1.93	-2.33	-1.97	-3.37	-4.97	-1.86	-3.37	-4.97
Total supply	**25.64**	**25.84**	**27.23**	**29.18**	**26.39**	**29.56**	**32.48**	**25.92**	**31.81**	**37.27**
Consumption by sector										
Residential	4.17	4.42	4.46	4.52	4.20	4.33	4.41	3.98	4.12	4.28
Commercial	2.90	3.10	3.16	3.27	3.09	3.28	3.41	3.35	3.57	3.85
Industrial[5]	7.14	8.00	8.09	8.20	8.11	8.52	8.79	8.24	8.68	9.22
Natural-gas-to-liquids heat and power[6]	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Natural gas to liquids production[7]	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Electric power[8]	9.25	7.82	8.81	10.33	8.19	10.06	12.10	7.31	11.23	14.99
Transportation[9]	0.04	0.08	0.08	0.08	0.21	0.28	0.22	0.48	0.85	0.76
Pipeline fuel	0.72	0.67	0.73	0.74	0.71	0.80	0.89	0.71	0.83	0.98
Lease and plant fuel[10]	1.42	1.59	1.74	1.86	1.71	2.11	2.50	1.69	2.35	2.98
Total	**25.64**	**25.68**	**27.06**	**29.01**	**26.23**	**29.39**	**32.31**	**25.76**	**31.63**	**37.05**
Discrepancy[11]	0.00	0.17	0.17	0.17	0.17	0.17	0.17	0.16	0.18	0.21
Lower 48 end of year dry reserves[1]	**320.09**	**334.75**	**352.47**	**388.50**	**342.80**	**382.58**	**427.94**	**347.18**	**402.59**	**492.37**

[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 fuel in motor vehicles, trains, and ships.
[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, 2012 values include net storage injections.
Note: Totals may not equal sum of components due to independent rounding. Data for 2012 are model results and may differ from official EIA data reports.
Sources: 2012 supply values; lease, plant, and pipeline fuel consumption: U.S. Energy Information Administration (EIA), *Natural Gas Monthly*, DOE/EIA-0130(2013/06) (Washington, DC, June 2013). Other 2012 consumption based on: EIA, *Monthly Energy Review*, DOE/EIA-0035(2013/09) (Washington, DC, September 2013). 2012 natural gas price at Henry Hub based on daily spot prices published in Natural Gas Intelligence. **Projections:** EIA, AEO2014 National Energy Modeling System runs LOWRESOURCE.D112913A, REF2014.D102413A, and HIGHRESOURCE.D112913B.

Table D8. Liquid fuels supply and disposition, oil and gas resource case
(million barrels per day, unless otherwise noted)

Supply, disposition, and prices	2012	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 (2012 dollars per barrel)										
Brent spot	111.65	98.61	96.57	91.58	122.90	118.99	106.55	145.02	141.46	124.74
West Texas Intermediate spot	94.12	96.56	94.57	89.69	120.83	116.99	104.76	142.96	139.46	122.97
Imported crude oil[1]	101.10	90.10	88.07	82.58	113.23	109.22	96.67	133.65	130.80	113.71
Crude oil supply										
Domestic production[2]	6.49	8.85	9.55	11.41	7.05	8.30	12.85	6.61	7.48	13.22
Alaska	0.53	0.44	0.44	0.49	0.24	0.24	0.69	0.31	0.26	1.00
Lower 48 States	5.96	8.42	9.12	10.93	6.81	8.06	12.16	6.30	7.22	12.22
Net imports	8.43	6.49	5.79	3.95	7.82	6.64	2.33	8.71	7.74	2.38
Gross imports	8.49	6.64	5.94	4.10	7.95	6.77	2.46	8.84	7.87	2.51
Exports	0.06	0.15	0.15	0.15	0.13	0.13	0.13	0.12	0.12	0.12
Other crude oil supply[3]	0.09	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total crude oil supply	**15.01**	**15.35**	**15.34**	**15.36**	**14.88**	**14.94**	**15.17**	**15.32**	**15.22**	**15.60**
Other petroleum supply	**0.10**	**0.15**	**0.23**	**0.10**	**-0.08**	**-0.34**	**-0.46**	**-0.34**	**-0.86**	**-1.74**
Net product imports	-0.92	-0.94	-0.86	-0.92	-1.07	-1.29	-1.32	-1.34	-1.82	-2.55
Gross refined product imports[4]	0.85	0.94	0.98	1.12	1.02	1.06	1.26	1.19	1.10	1.08
Unfinished oil imports	0.60	0.52	0.52	0.52	0.49	0.49	0.49	0.45	0.45	0.45
Blending component imports	0.62	0.62	0.62	0.61	0.50	0.50	0.49	0.40	0.40	0.38
Exports	2.98	3.02	2.97	3.18	3.08	3.33	3.56	3.38	3.76	4.46
Refinery processing gain[5]	1.08	1.10	1.08	1.02	0.99	0.96	0.86	0.99	0.95	0.82
Product stock withdrawal	-0.06	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Other non-petroleum supply	**3.48**	**3.99**	**3.96**	**4.34**	**3.85**	**4.32**	**4.77**	**3.55**	**4.36**	**5.99**
Supply from renewable sources	0.89	1.01	1.01	1.02	1.04	1.04	1.04	1.06	1.07	1.08
Ethanol	0.83	0.89	0.90	0.90	0.92	0.91	0.92	0.96	0.95	0.96
Domestic production	0.84	0.83	0.84	0.84	0.85	0.86	0.87	0.87	0.86	0.89
Net imports	-0.02	0.06	0.06	0.06	0.07	0.06	0.05	0.08	0.08	0.07
Biodiesel	0.06	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09
Domestic production	0.06	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08
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	0.03	0.03	0.03	0.03	0.04	0.03	0.01	0.03	0.03
Liquids from gas	2.40	2.68	2.65	3.05	2.50	2.98	3.44	2.17	2.98	4.62
Natural gas plant liquids	2.40	2.68	2.65	3.05	2.50	2.98	3.44	2.17	2.98	4.62
Gas-to-liquids	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Liquids from coal	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Other[7]	0.19	0.30	0.30	0.27	0.31	0.30	0.29	0.32	0.31	0.29
Total primary supply[8]	**18.59**	**19.49**	**19.52**	**19.80**	**18.64**	**18.93**	**19.48**	**18.52**	**18.72**	**19.85**
Net import share of product supplied (percent)	40.3	28.8	25.6	15.7	36.6	28.6	5.5	40.3	32.2	-0.4
Net expenditures for imports of crude oil and petroleum products (billion 2012 dollars)	313.70	226.68	198.85	131.35	337.87	278.60	94.87	441.03	385.39	112.60
Lower 48 end of year reserves[2] (billion barrels)	**24.71**	**29.22**	**31.78**	**37.19**	**29.86**	**34.42**	**47.13**	**32.56**	**35.45**	**48.12**

Table D8. Liquid fuels supply and disposition, oil and gas resource case (continued)
(million barrels per day, unless otherwise noted)

Supply, disposition, and prices	2012	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
Refined petroleum product prices to the transportation sector (2012 dollars per gallon)										
Propane	2.30	2.33	2.27	2.20	2.54	2.45	2.27	2.68	2.63	2.42
Ethanol (E85)[9]	3.33	2.46	2.43	2.36	2.68	2.65	2.49	3.36	3.37	3.17
Ethanol wholesale price	2.58	2.71	2.66	2.64	2.62	2.52	2.41	2.64	2.65	2.54
Motor gasoline[10]	3.69	3.11	3.08	2.96	3.50	3.43	3.13	3.92	3.90	3.49
Jet fuel[11]	3.10	2.68	2.63	2.49	3.32	3.20	2.81	3.89	3.79	3.25
Distillate fuel oil[12]	3.95	3.72	3.67	3.54	4.32	4.20	3.85	4.79	4.73	4.26
Residual fuel oil	3.00	1.90	1.86	1.78	2.41	2.32	2.13	2.86	2.78	2.47
Residual fuel oil (2012 dollars per barrel)	126.17	79.86	78.31	74.64	101.27	97.43	89.26	120.14	116.65	103.86

[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 2012 are model results and may differ from official EIA data reports.
Sources: 2012 product supplied data and imported crude oil price based on: U.S. Energy Information Administration (EIA), *Monthly Energy Review*, DOE/EIA-0035(2013/09) (Washington, DC, September 2013). 2012 crude oil spot prices: Thomson Reuters. 2012 transportation sector prices based on: EIA, Form EIA-782A, "Refiners'/Gas Plant Operators' Monthly Petroleum Product Sales Report". 2012 E85 prices derived from monthly prices in the Clean Cities Alternative Fuel Price Report. 2012 wholesale ethanol prices derived from Bloomberg U.S. average rack price. Other 2012 data: EIA, *Petroleum Supply Annual 2012*, DOE/EIA-0340(2012)/1 (Washington, DC, September 2013). **Projections:** EIA, AEO2014 National Energy Modeling System runs LOWRESOURCE.D112913A, REF2014.D102413A, and HIGHRESOURCE.D112913B.

Table D9. Key transportation results, oil and gas resource cases

Consumption and indicators	2012	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
Level of travel										
(billion vehicle miles traveled)										
Light-duty vehicles less than 8,501 pounds	2,662	2,846	2,851	2,869	3,118	3,138	3,201	3,422	3,434	3,529
Commercial light trucks[1]	63	76	76	77	88	90	91	101	103	106
Freight trucks greater than 10,000 pounds	245	308	310	317	351	362	377	398	411	437
(billion seat miles available)										
Air	990	1,064	1,064	1,065	1,135	1,135	1,135	1,199	1,199	1,199
(billion ton miles traveled)										
Rail	1,729	1,675	1,624	1,581	1,761	1,738	1,688	1,763	1,736	1,647
Domestic shipping	378	386	390	406	356	369	403	360	371	419
Energy efficiency indicators										
(miles per gallon)										
Tested new light-duty vehicle[2]	31.7	38.7	38.6	38.5	47.9	47.8	47.4	48.1	48.2	47.7
New car[2]	36.3	44.2	44.2	44.2	55.2	55.4	55.2	55.4	55.6	55.3
New light truck[2]	27.5	33.7	33.7	33.6	40.8	40.7	40.6	40.9	40.8	40.7
On-road new light-duty vehicle[3]	25.6	31.2	31.2	31.1	38.7	38.6	38.3	38.9	38.9	38.5
New car[3]	29.7	36.1	36.1	36.1	45.1	45.2	45.1	45.2	45.4	45.2
New light truck[3]	22.0	27.0	27.0	26.9	32.7	32.6	32.5	32.7	32.7	32.6
Light-duty stock[4]	21.5	25.1	25.1	25.1	32.6	32.6	32.4	37.2	37.2	36.9
New commercial light truck[1]	18.1	20.9	20.9	20.8	24.5	24.5	24.4	24.6	24.6	24.5
Stock commercial light truck[1]	15.2	18.0	18.0	18.0	22.5	22.5	22.5	24.5	24.5	24.4
Freight truck	6.7	7.3	7.3	7.3	7.7	7.7	7.7	7.8	7.8	7.8
(seat miles per gallon)										
Aircraft	62.4	63.9	63.9	63.9	67.0	67.0	67.0	71.5	71.5	71.6
(ton miles per thousand Btu)										
Rail	3.4	3.6	3.6	3.6	3.9	3.9	3.9	4.2	4.2	4.2
Domestic shipping	4.7	5.0	5.0	5.0	5.4	5.4	5.4	5.8	5.8	5.8
Energy use by mode (quadrillion Btu)										
Light-duty vehicles	15.49	14.21	14.24	14.34	12.00	12.09	12.38	11.53	11.58	12.00
Commercial light trucks[1]	0.52	0.53	0.53	0.53	0.49	0.50	0.51	0.52	0.53	0.54
Bus transportation	0.24	0.25	0.25	0.25	0.27	0.27	0.27	0.29	0.29	0.29
Freight trucks	5.02	5.83	5.87	6.00	6.26	6.47	6.73	6.97	7.23	7.71
Rail, passenger	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.06	0.06	0.06
Rail, freight	0.48	0.46	0.45	0.43	0.45	0.45	0.43	0.43	0.42	0.40
Shipping, domestic	0.10	0.09	0.09	0.10	0.08	0.08	0.09	0.07	0.08	0.09
Shipping, international	0.58	0.59	0.59	0.59	0.60	0.60	0.60	0.61	0.61	0.61
Recreational boats	0.24	0.25	0.25	0.26	0.27	0.27	0.28	0.28	0.28	0.29
Air	2.47	2.60	2.60	2.60	2.68	2.69	2.69	2.70	2.70	2.70
Military use	0.70	0.64	0.64	0.64	0.68	0.68	0.68	0.77	0.77	0.77
Lubricants	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12
Pipeline fuel	0.73	0.69	0.74	0.75	0.72	0.82	0.91	0.72	0.85	1.00
Total	**26.74**	**26.31**	**26.41**	**26.66**	**24.69**	**25.09**	**25.75**	**25.07**	**25.51**	**26.59**

Table D9. Key transportation results, oil and gas resource cases (continued)

Consumption and indicators	2012	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
Energy use by fuel (quadrillion Btu)										
Propane	0.05	0.05	0.05	0.05	0.05	0.06	0.06	0.07	0.07	0.07
Motor gasoline[5]	16.33	14.97	15.00	15.11	12.59	12.69	13.02	12.04	12.09	12.56
of which: E85[6]	0.01	0.19	0.19	0.18	0.49	0.46	0.43	0.34	0.33	0.29
Jet fuel[7]	3.00	3.08	3.08	3.08	3.20	3.20	3.20	3.28	3.28	3.28
Distillate fuel oil[8]	5.82	6.67	6.70	6.81	7.12	7.25	7.55	7.65	7.54	8.08
Residual fuel oil	0.58	0.58	0.58	0.58	0.59	0.59	0.59	0.60	0.60	0.60
Other petroleum[9]	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15
Liquid fuels and other petroleum	25.93	25.50	25.55	25.78	23.70	23.94	24.57	23.79	23.73	24.74
Pipeline fuel natural gas	0.73	0.69	0.74	0.75	0.72	0.82	0.91	0.72	0.85	1.00
Compressed/liquefied natural gas	0.04	0.08	0.08	0.08	0.21	0.28	0.22	0.48	0.86	0.77
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	0.04	0.06	0.06	0.06
Delivered energy	**26.72**	**26.30**	**26.40**	**26.65**	**24.69**	**25.08**	**25.74**	**25.06**	**25.50**	**26.58**
Electricity related losses	0.05	0.06	0.06	0.06	0.09	0.08	0.08	0.12	0.12	0.11
Total	**26.77**	**26.36**	**26.47**	**26.71**	**24.77**	**25.17**	**25.82**	**25.18**	**25.62**	**26.68**

[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]Includes ethanol and ethers blended into gasoline.
[6]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.
[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 2012 are model results and may differ from official EIA data reports.
Source: 2012 consumption based on: U.S. Energy Information Administration (EIA), *Monthly Energy Review*, DOE/EIA-0384(2013/09) (Washington, DC, September 2013). Other 2012 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 2011*, DOE/EIA-0214(2011) (Washington, DC, June 2013); 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, AEO2014 National Energy Modeling System runs LOWRESOURCE.D112913A, REF2014.D102413A, and HIGHRESOURCE.D112913B.

Table D10. Key transportation results, vehicle miles traveled cases

Consumption and indicators	2012	2020			2030			2040		
		Low VMT	Reference	High VMT	Low VMT	Reference	High VMT	Low VMT	Reference	High VMT
Level of travel										
(billion vehicle miles traveled)										
Light-duty vehicles less than 8,501 pounds	2,662	2,752	2,851	2,954	2,772	3,138	3,301	2,793	3,434	3,624
Commercial light trucks[1]	63	75	76	77	86	90	91	97	103	105
Freight trucks greater than 10,000 pounds	245	310	310	310	362	362	362	410	411	411
(billion seat miles available)										
Air	990	1,064	1,064	1,064	1,135	1,135	1,135	1,199	1,199	1,199
(billion ton miles traveled)										
Rail	1,729	1,624	1,624	1,620	1,736	1,738	1,736	1,738	1,736	1,737
Domestic shipping	378	390	390	390	368	369	369	370	371	371
Vehicles miles traveled per licensed driver (thousand miles)	12.5	11.8	12.2	12.7	11.0	12.5	13.1	10.4	12.8	13.5
Licensed drivers (millions)	213.1	233.5	233.5	233.5	252.0	252.0	252.0	268.6	268.6	268.6
Energy efficiency indicators										
(miles per gallon)										
Tested new light-duty vehicle[2]	31.7	38.6	38.6	38.7	47.8	47.8	47.9	48.0	48.2	48.2
New car[2]	36.3	44.2	44.2	44.2	55.4	55.4	55.2	55.5	55.6	55.4
New light truck[2]	27.5	33.7	33.7	33.7	40.9	40.7	40.9	40.9	40.8	40.9
On-road new light-duty vehicle[3]	25.6	31.2	31.2	31.3	38.6	38.6	38.7	38.8	38.9	39.0
New car[3]	29.7	36.1	36.1	36.1	45.2	45.2	45.1	45.3	45.4	45.3
New light truck[3]	22.0	27.0	27.0	27.0	32.7	32.6	32.7	32.8	32.7	32.8
Light-duty stock[4]	21.5	25.1	25.1	25.1	32.6	32.6	32.6	37.2	37.2	37.3
New commercial light truck[1]	18.1	20.9	20.9	20.9	24.6	24.5	24.6	24.7	24.6	24.7
Stock commercial light truck[1]	15.2	18.0	18.0	18.0	22.6	22.5	22.6	24.6	24.5	24.6
Freight truck	6.7	7.3	7.3	7.3	7.7	7.7	7.7	7.8	7.8	7.8
(seat miles per gallon)										
Aircraft	62.4	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	3.6	3.6	3.6	3.9	3.9	3.9	4.2	4.2	4.2
Domestic shipping	4.7	5.0	5.0	5.0	5.4	5.4	5.4	5.8	5.8	5.8
Energy use by mode (quadrillion Btu)										
Light-duty vehicles	15.49	13.74	14.24	14.75	10.66	12.09	12.71	9.42	11.58	12.21
Commercial light trucks[1]	0.52	0.52	0.53	0.54	0.48	0.50	0.51	0.49	0.53	0.53
Bus transportation	0.24	0.25	0.25	0.25	0.27	0.27	0.27	0.29	0.29	0.29
Freight trucks	5.02	5.87	5.87	5.87	6.46	6.47	6.47	7.22	7.23	7.24
Rail, passenger	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.06	0.06	0.06
Rail, freight	0.48	0.45	0.45	0.45	0.45	0.45	0.45	0.42	0.42	0.42
Shipping, domestic	0.10	0.09	0.09	0.09	0.08	0.08	0.08	0.08	0.08	0.08
Shipping, international	0.58	0.59	0.59	0.59	0.60	0.60	0.60	0.61	0.61	0.61
Recreational boats	0.24	0.25	0.25	0.25	0.27	0.27	0.27	0.29	0.28	0.28
Air	2.47	2.60	2.60	2.60	2.68	2.69	2.69	2.70	2.70	2.70
Military use	0.70	0.64	0.64	0.64	0.68	0.68	0.68	0.77	0.77	0.77
Lubricants	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12
Pipeline fuel	0.73	0.74	0.74	0.74	0.81	0.82	0.82	0.84	0.85	0.84
Total	**26.74**	**25.91**	**26.41**	**26.94**	**23.63**	**25.09**	**25.72**	**23.31**	**25.51**	**26.15**
Energy use by fuel (quadrillion Btu)										
Propane	0.05	0.05	0.05	0.05	0.05	0.06	0.06	0.06	0.07	0.07
Motor gasoline[5]	16.33	14.51	15.00	15.50	11.31	12.69	13.28	10.04	12.09	12.68
of which: E85[6]	0.01	0.21	0.19	0.15	0.56	0.46	0.39	0.49	0.33	0.34
Jet fuel[7]	3.00	3.08	3.08	3.08	3.20	3.20	3.20	3.28	3.28	3.28
Distillate fuel oil[8]	5.82	6.68	6.70	6.71	7.18	7.25	7.27	7.41	7.54	7.58
Residual fuel oil	0.58	0.58	0.58	0.58	0.59	0.59	0.59	0.60	0.60	0.60
Other petroleum[9]	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15
Liquid fuels and other petroleum	25.93	25.05	25.55	26.07	22.48	23.94	24.55	21.54	23.73	24.37
Pipeline fuel natural gas	0.73	0.74	0.74	0.74	0.81	0.82	0.82	0.84	0.85	0.84
Compressed/liquefied natural gas	0.04	0.08	0.08	0.08	0.28	0.28	0.29	0.86	0.86	0.86
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	0.04	0.05	0.06	0.06
Delivered energy	**26.72**	**25.90**	**26.40**	**26.93**	**23.62**	**25.08**	**25.71**	**23.30**	**25.50**	**26.14**

Table D10. Key transportation results, vehicle miles traveled cases (continued)

Consumption and indicators	2012	2020			2030			2040		
		Low VMT	Reference	High VMT	Low VMT	Reference	High VMT	Low VMT	Reference	High VMT
Carbon dioxide emissions in the transportation sector (million metric tons)										
Petroleum[10]	1,771	1,701	1,734	1,769	1,521	1,618	1,662	1,451	1,600	1,642
Natural gas[11]	41	44	44	44	58	58	59	91	91	91
Total	**1,812**	**1,745**	**1,777**	**1,812**	**1,579**	**1,677**	**1,721**	**1,542**	**1,691**	**1,733**

[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]Includes ethanol and ethers blended into gasoline.
[6]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.
[7]Includes only kerosene type.
[8]Diesel fuel for on- and off- road use.
[9]Includes aviation gasoline and lubricants.
[10]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 2012, international bunker fuels accounted for 90 to 126 million metric tons annually.
[11]Include pipeline fuel natural gas and natural gas used as fuel in motor vehicles, trains, and ships.
VMT = Vehicle miles traveled.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Data for 2012 are model results and may differ from official EIA data reports.
Source: 2012 consumption based on: U.S. Energy Information Administration (EIA), *Monthly Energy Review*, DOE/EIA-0384(2013/09) (Washington, DC, September 2013). Other 2012 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 2011*, DOE/EIA-0214(2011) (Washington, DC, June 2013); 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, AEO2014 National Energy Modeling System runs LOWVMT.D020314B, REF2014.D102413A, and HIGHVMT.D020314D.

Table D11. Key transportation results, rail liquefied natural gas cases

Consumption and indicators	2012	2020 Low Rail LNG	2020 Reference	2020 High Rail LNG	2030 Low Rail LNG	2030 Reference	2030 High Rail LNG	2040 Low Rail LNG	2040 Reference	2040 High Rail LNG
Rail travel										
(billion ton miles traveled)	1,729	1,622	1,624	1,622	1,742	1,738	1,739	1,734	1,736	1,737
Rail efficiency										
(ton miles per thousand Btu)	3.4	3.6	3.6	3.6	3.9	3.9	3.9	4.2	4.2	4.2
Energy use by mode (quadrillion Btu)										
Light-duty vehicles	15.49	14.24	14.24	14.24	12.09	12.09	12.09	11.58	11.58	11.59
Commercial light trucks[1]	0.52	0.53	0.53	0.53	0.50	0.50	0.50	0.53	0.53	0.53
Bus transportation	0.24	0.25	0.25	0.25	0.27	0.27	0.27	0.29	0.29	0.29
Freight trucks	5.02	5.87	5.87	5.87	6.47	6.47	6.47	7.24	7.23	7.23
Rail, passenger	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.06	0.06	0.06
Rail, freight	0.48	0.45	0.45	0.45	0.45	0.45	0.44	0.41	0.42	0.41
Distillate fuel oil	0.48	0.44	0.44	0.42	0.41	0.37	0.21	0.35	0.27	0.02
Liquefied natural gas	0.00	0.00	0.00	0.02	0.04	0.08	0.24	0.06	0.15	0.39
Shipping, domestic	0.10	0.09	0.09	0.09	0.08	0.08	0.08	0.08	0.08	0.08
Shipping, international	0.58	0.59	0.59	0.59	0.60	0.60	0.60	0.61	0.61	0.61
Recreational boats	0.24	0.25	0.25	0.25	0.27	0.27	0.27	0.28	0.28	0.28
Air	2.47	2.60	2.60	2.60	2.69	2.69	2.69	2.70	2.70	2.70
Military use	0.70	0.64	0.64	0.64	0.68	0.68	0.68	0.77	0.77	0.76
Lubricants	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12
Pipeline fuel	0.73	0.74	0.74	0.74	0.83	0.82	0.83	0.85	0.85	0.85
Total	**26.74**	**26.41**	**26.41**	**26.41**	**25.10**	**25.09**	**25.10**	**25.51**	**25.51**	**25.51**
Energy use by fuel (quadrillion Btu)										
Propane	0.05	0.05	0.05	0.05	0.06	0.06	0.06	0.07	0.07	0.07
Motor gasoline[2]	16.33	15.00	15.00	15.00	12.69	12.69	12.69	12.09	12.09	12.09
of which: E85[3]	0.01	0.19	0.19	0.19	0.46	0.46	0.46	0.33	0.33	0.34
Jet fuel[4]	3.00	3.08	3.08	3.08	3.20	3.20	3.20	3.28	3.28	3.28
Distillate fuel oil[5]	5.82	6.70	6.70	6.68	7.29	7.25	7.09	7.61	7.54	7.32
Residual fuel oil	0.58	0.58	0.58	0.58	0.59	0.59	0.59	0.60	0.60	0.60
Other petroleum[6]	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15
Liquid fuels and other petroleum	25.93	25.55	25.55	25.53	23.98	23.94	23.78	23.79	23.73	23.51
Pipeline fuel natural gas	0.73	0.74	0.74	0.74	0.83	0.82	0.83	0.85	0.85	0.85
Compressed/liquefied natural gas	0.04	0.08	0.08	0.10	0.24	0.28	0.44	0.79	0.86	1.07
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	0.04	0.06	0.06	0.06
Delivered energy	**26.72**	**26.40**	**26.40**	**26.40**	**25.09**	**25.08**	**25.09**	**25.50**	**25.50**	**25.51**
Carbon dioxide emissions in the transportation sector (million metric tons)										
Petroleum[7]	1,771	1,734	1,734	1,732	1,621	1,618	1,607	1,605	1,600	1,585
Natural gas[8]	41	44	44	45	57	58	67	87	91	103
Total	**1,812**	**1,778**	**1,777**	**1,777**	**1,678**	**1,677**	**1,674**	**1,693**	**1,691**	**1,687**

[1]Commercial trucks 8,501 to 10,000 pounds gross vehicle weight rating.
[2]Includes ethanol and ethers blended into gasoline.
[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]Includes only kerosene type.
[5]Diesel fuel for on- and off- road use.
[6]Includes aviation gasoline and lubricants.
[7]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 2012, international bunker fuels accounted for 90 to 126 million metric tons annually.
[8]Includes pipeline fuel natural gas and natural gas used as fuel in motor vehicles, trains, and ships.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Data for 2012 are model results and may differ from official EIA data reports.
Source: 2012 consumption based on: U.S. Energy Information Administration (EIA), *Monthly Energy Review*, DOE/EIA-0384(2013/09) (Washington, DC, September 2013). Other 2012 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 2011*, DOE/EIA-0214(2011) (Washington, DC, June 2013); 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, AEO2014 National Energy Modeling System runs RLNGLOW20.D012914C, REF2014.D102413A, and RLNGHIGH20.D012914C.

Table D12. Key results for energy savings and industrial competitiveness act case
(quadrillion Btu per year, unless otherwise noted)

Consumption, emissions	2012	2020		2030		2040	
		Reference	ESICA	Reference	ESICA	Reference	ESICA
Energy consumption							
Residential	**10.42**	**10.74**	**10.70**	**10.83**	**10.71**	**10.94**	**10.78**
Propane, kerosene, and distillate fuel oil	1.02	0.89	0.88	0.75	0.75	0.66	0.66
Natural gas	4.26	4.56	4.52	4.43	4.35	4.21	4.10
Renewable energy[1]	0.45	0.46	0.46	0.44	0.44	0.42	0.41
Electricity	4.69	4.84	4.83	5.21	5.18	5.65	5.62
Commercial	**8.29**	**8.78**	**8.76**	**9.38**	**9.31**	**10.22**	**10.14**
Liquid fuels and other petroleum[2]	0.63	0.68	0.68	0.67	0.67	0.68	0.67
Natural gas	2.96	3.23	3.22	3.35	3.31	3.65	3.59
Coal	0.04	0.04	0.04	0.04	0.04	0.04	0.04
Renewable energy[3]	0.13	0.13	0.13	0.13	0.13	0.13	0.13
Electricity	4.52	4.69	4.68	5.18	5.16	5.72	5.70
Industrial[4]	**23.63**	**27.71**	**27.71**	**29.62**	**29.59**	**30.22**	**30.19**
Liquid fuels and other petroleum[5]	8.06	9.56	9.55	10.10	10.08	10.10	10.07
Natural gas	8.75	10.04	10.04	10.87	10.86	11.28	11.27
Coal	1.48	1.57	1.57	1.52	1.52	1.44	1.44
Renewable energy[6]	2.00	2.50	2.50	2.79	2.79	3.07	3.07
Electricity	3.35	4.04	4.04	4.33	4.33	4.34	4.35
Transportation	**26.72**	**26.40**	**26.40**	**25.08**	**25.08**	**25.50**	**25.50**
Liquid fuels and other petroleum[7]	25.93	25.55	25.55	23.94	23.94	23.73	23.73
Pipeline fuel natural gas	0.73	0.74	0.74	0.82	0.81	0.85	0.84
Compressed / liquefied natural gas	0.04	0.08	0.08	0.28	0.28	0.86	0.86
Electricity and liquid hydrogen	0.02	0.03	0.03	0.05	0.05	0.07	0.07
Electric power[8]	**38.53**	**40.70**	**40.66**	**43.12**	**43.04**	**45.20**	**45.08**
Natural gas	9.46	9.00	8.99	10.28	10.23	11.48	11.33
Steam coal	15.82	16.95	16.95	17.44	17.43	17.27	17.27
Nuclear / uranium[9]	8.05	8.15	8.15	8.18	8.18	8.49	8.56
Renewable energy[10]	4.59	6.08	6.06	6.68	6.68	7.44	7.41
Other[11]	0.62	0.52	0.52	0.53	0.53	0.53	0.52
Total energy consumption	**95.02**	**100.73**	**100.63**	**103.27**	**103.02**	**106.31**	**105.97**
Carbon dioxide emissions (million metric tons)							
by sector							
Residential	295	302	300	286	281	268	262
Commercial	206	224	223	230	227	246	242
Industrial[4]	937	1,060	1,059	1,107	1,106	1,123	1,121
Transportation	1,812	1,777	1,777	1,677	1,676	1,691	1,691
Electric power[8]	2,039	2,112	2,111	2,227	2,223	2,271	2,263
by fuel							
Petroleum[12]	2,254	2,252	2,251	2,136	2,134	2,113	2,111
Natural gas	1,366	1,447	1,443	1,572	1,563	1,694	1,676
Coal	1,657	1,766	1,766	1,807	1,805	1,780	1,780
Other[13]	12	12	12	12	12	12	12
Total carbon dioxide emissions	**5,290**	**5,476**	**5,472**	**5,527**	**5,513**	**5,599**	**5,579**

[1]Includes wood used for residential heating. Excludes nonmarketed renewable energy consumption for geothermal heat pumps, buildings photovoltaic systems, and solar thermal water heaters.
[2]Includes propane, motor gasoline, ethanol and ethers, kerosene, distillate fuel oil, and residual fuel oil.
[3]Includes commercial sector consumption of wood and wood waste, landfill gas, municipal waste, and other biomass for combined heat and power. Excludes nonmarketed renewable energy consumption for geothermal heat pumps, buildings photovoltaic systems, and solar thermal water heaters.
[4]Includes energy for combined heat and power plants that have a non-regulatory status, and small on-site generating systems.
[5]Includes ethane, natural gasoline, refinery olefins, liquefied petroleum gases, motor gasoline, ethanol and ethers, distillate fuel oil, residual fuel oil, petrochemical feedstocks, petroleum coke, asphalt, road oil, lubricants, still gas, and miscellaneous petroleum products.
[6]Includes consumption of energy produced from hydroelectric, wood and wood waste, municipal waste, and other biomass sources. Excludes ethanol.
[7]Includes propane, motor gasoline, ethanol and ethers, jet fuel, distillate fuel oil, residual fuel oil, aviation gasoline, and lubricants.
[8]Includes consumption of energy by electricity-only and combined heat and power plants that have a regulatory status.
[9]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.
[10]Includes conventional hydroelectric, geothermal, wood and wood waste, biogenic municipal waste, other biomass, wind, photovoltaic, and solar thermal sources. Excludes net electricity imports.
[11]Includes distillate fuel oil, residual fuel oil, non-biogenic municipal waste, and net electricity imports.
[12]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 2012, international bunker fuels accounted for 90 to 126 million metric tons annually.
[13]Includes emissions from geothermal power and emissions from non-biogenic municipal waste.
ESICA = Energy Savings and Industrial Competitiveness Act.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Data for 2012 are model results and may differ from official EIA data reports.
Source: U.S. Energy Information Administration, AEO2014 National Energy Modeling System, runs REF2014.D102413A, and ESICA.D021014A.

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	2012	2020		2030		2040	
		Reference	No GHG Concern	Reference	No GHG Concern	Reference	No GHG Concern
Production[1]	1,016	1,077	1,084	1,127	1,136	1,121	1,159
Appalachia	293	261	262	253	255	247	252
Interior	180	228	231	266	268	289	310
West	543	587	591	607	613	584	597
Waste coal supplied[2]	11	14	14	15	15	19	20
Net imports[3]	-118	-126	-126	-147	-147	-160	-160
Total supply[4]	**909**	**965**	**971**	**995**	**1,004**	**979**	**1,020**
Consumption by sector							
Commercial and institutional	2	2	2	2	2	2	2
Coke plants	21	22	22	21	21	18	18
Other industrial[5]	43	49	49	49	49	50	50
Coal-to-liquids	0	0	0	0	0	0	0
Electric power[6]	825	892	898	923	931	909	950
Total coal consumption	**891**	**965**	**971**	**995**	**1,004**	**979**	**1,020**
Average minemouth price[7]							
(2012 dollars per short ton)	39.94	46.52	46.53	53.15	53.15	59.16	59.33
(2012 dollars per million Btu)	1.98	2.33	2.33	2.67	2.67	2.96	2.98
Delivered prices[8] (2012 dollars per short ton)							
Commercial and institutional	90.76	95.19	95.30	101.39	102.33	108.37	109.02
Coke plants	190.55	221.01	221.03	249.43	249.52	267.23	267.29
Other industrial[5]	70.32	76.39	76.44	82.64	83.42	89.22	90.11
Coal to liquids	- -	- -	- -	- -	- -	- -	- -
Electric power[6]	46.13	49.63	49.71	55.32	55.37	60.61	61.20
Average	**50.85**	**54.99**	**55.04**	**60.85**	**60.90**	**65.97**	**66.35**
Electric power (2012 dollars per million Btu)[6]	2.39	2.61	2.62	2.93	2.93	3.19	3.23
Exports[9]	118.43	136.76	136.75	145.97	146.13	150.13	150.56
Electricity generating capacity (gigawatts)							
Cumulative capacity additions[10]							
Coal	0.0	2.5	2.5	2.5	4.1	2.6	13.0
Conventional with scrubber	0.0	1.0	1.0	1.0	2.6	1.1	11.5
IGCC without sequestration	0.0	0.6	0.6	0.6	0.6	0.6	0.6
IGCC 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	0.0	0.0	0.0	0.0
Natural gas	0.0	41.7	40.6	142.6	139.3	255.2	246.4
Nuclear / uranium	0.0	5.5	5.5	5.8	5.5	9.7	7.2
Renewables[12]	0.0	36.4	36.5	49.6	49.3	83.3	77.7
Other	0.0	0.6	0.6	0.6	0.6	0.6	0.6
Total cumulative additions	**0.0**	**86.7**	**85.7**	**201.1**	**198.9**	**351.5**	**344.9**
Cumulative coal capacity retirements[13]	0.0	49.9	48.5	50.7	49.3	50.8	49.4
Total coal capacity	310.0	262.6	264.0	261.8	264.8	261.8	273.6
Liquids from coal (million barrels per day)	0.00	0.00	0.00	0.00	0.00	0.00	0.00

[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. Prices weighted by production, which differs from average minemouth prices published in EIA data reports where it is weighted by reported sales.
[8]Prices weighted by consumption tonnage; weighted average excludes export free-alongside-ship prices.
[9]Free-alongside-ship price at U.S. port of exit.
[10]Cumulative additions after December 31, 2012. 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.
[13]Cumulative retirements after December 31, 2012. Includes retirements of electricity-only and combined heat and power plants that have a regulatory status.
- - = Not applicable.
Btu = British thermal unit.
GHG = Greenhouse gas.
IGCC = Integrated coal-gasification combined cycle.
Note: Totals may not equal sum of components due to independent rounding. Data for 2012 are model results and may differ from official EIA data reports.
Sources: 2012 data based on: U.S. Energy Information Administration (EIA), *Annual Coal Report 2012*, DOE/EIA-0584(2012) (Washington, DC, December 2013); EIA, *Quarterly Coal Report, October-December 2012*, DOE/EIA-0121(2012/4Q) (Washington, DC, March 2013); and EIA, AEO2014 National Energy Modeling System run REF2014.D102413A. **Projections:** EIA, AEO2014 National Energy Modeling System runs REF2014.D102413A and NOGHGCONCERN.D120413A.

Table D14. Key results and assumptions for coal cost cases
(million short tons per year, unless otherwise noted)

Supply, disposition, prices, electricity generating capacity, and costs	2012	2020			2040			Annual growth 2012-2040 (percent)		
		Low Coal Cost	Reference	High Coal Cost	Low Coal Cost	Reference	High Coal Cost	Low Coal Cost	Reference	High Coal Cost
Production[1]	1,016	1,122	1,077	1,003	1,244	1,121	814	0.7%	0.3%	-0.8%
Appalachia	293	271	261	247	293	247	200	0.0%	-0.6%	-1.4%
Interior	180	230	228	225	268	289	253	1.4%	1.7%	1.2%
West	543	622	587	530	683	584	360	0.8%	0.3%	-1.5%
Waste coal supplied[2]	11	11	14	15	11	19	27	0.1%	1.9%	3.2%
Net imports[3]	-118	-127	-126	-122	-201	-160	-69	1.9%	1.1%	-1.9%
Total supply[4]	**909**	**1,006**	**965**	**895**	**1,054**	**979**	**771**	**0.5%**	**0.3%**	**-0.6%**
Consumption by sector										
Commercial and institutional	2	2	2	2	2	2	2	0.0%	-0.1%	-0.2%
Coke plants	21	22	22	22	18	18	17	-0.4%	-0.5%	-0.6%
Other industrial[5]	43	49	49	49	51	50	49	0.6%	0.5%	0.4%
Coal-to-liquids	0	0	0	0	0	0	0	- -	- -	- -
Electric power[6]	825	933	892	822	983	909	705	0.6%	0.3%	-0.6%
Total coal use	**891**	**1,006**	**965**	**895**	**1,054**	**979**	**773**	**0.6%**	**0.3%**	**-0.5%**
Average minemouth price[7]										
(2012 dollars per short ton)	39.94	39.46	46.52	55.11	32.29	59.16	113.47	-0.8%	1.4%	3.8%
(2012 dollars per million Btu)	1.98	1.97	2.33	2.76	1.61	2.96	5.54	-0.7%	1.4%	3.7%
Delivered prices[8] (2012 dollars per short ton)										
Commercial and institutional	90.76	86.19	95.19	105.18	70.73	108.37	165.32	-0.9%	0.6%	2.2%
Coke plants	190.55	197.05	221.01	248.69	170.56	267.23	428.62	-0.4%	1.2%	2.9%
Other industrial[5]	70.32	68.17	76.39	85.17	55.92	89.22	141.81	-0.8%	0.9%	2.5%
Coal to liquids	- -	- -	- -	- -	- -	- -	- -	- -	- -	- -
Electric power[6]										
(2012 dollars per short ton)	46.13	44.13	49.63	55.83	35.89	60.61	105.06	-0.9%	1.0%	3.0%
(2012 dollars per million Btu)	2.39	2.31	2.61	2.95	1.89	3.19	5.36	-0.8%	1.0%	2.9%
Average	**50.85**	**48.76**	**54.99**	**62.22**	**39.28**	**65.97**	**114.80**	**-0.9%**	**0.9%**	**3.0%**
Exports[9]	118.43	120.29	136.76	155.84	96.59	150.13	250.91	-0.7%	0.9%	2.7%
Electricity generating capacity (gigawatts)										
Capacity										
Coal	310.0	269.1	262.6	244.2	274.0	261.8	243.3	-0.4%	-0.6%	-0.9%
Conventional	306.2	263.8	257.3	238.9	268.7	256.5	238.0	0.0	0.0	0.0
IGCC without sequestration	0.4	1.0	1.0	1.0	1.0	1.0	1.0	0.0	0.0	0.0
IGCC with sequestration	0.0	0.9	0.9	0.9	0.9	0.9	0.9	- -	- -	- -
End-use generators[10]	3.4	3.4	3.4	3.4	3.4	3.4	3.4	0.0%	0.0%	0.0%
Natural gas	367.9	397.3	401.5	410.7	609.5	613.7	622.8	1.8%	1.8%	1.9%
Nuclear / uranium	102.1	97.8	97.8	97.8	100.5	102.0	101.4	-0.1%	0.0%	0.0%
Renewables[11]	159.4	195.1	194.9	196.0	248.0	241.8	239.0	1.6%	1.5%	1.5%
Other	126.3	112.6	112.6	111.4	96.8	96.2	94.7	-0.9%	-1.0%	-1.0%
Total capacity	**1,065.8**	**1,072.0**	**1,069.5**	**1,060.2**	**1,328.9**	**1,315.6**	**1,301.3**	**0.8%**	**0.8%**	**0.7%**
Cumulative capacity additions[12]										
Coal	0.0	2.5	2.5	2.5	8.2	2.6	2.5	- -	- -	- -
Conventional with scrubber	0.0	1.0	1.0	1.0	6.8	1.1	1.0	- -	- -	- -
IGCC without sequestration	0.0	0.6	0.6	0.6	0.6	0.6	0.6	- -	- -	- -
IGCC with sequestration	0.0	0.9	0.9	0.9	0.9	0.9	0.9	- -	- -	- -
End-use generators[10]	0.0	0.0	0.0	0.0	0.0	0.0	0.0	- -	- -	- -
Natural gas	0.0	37.5	41.7	51.1	251.0	255.2	264.3	- -	- -	- -
Nuclear / uranium	0.0	5.5	5.5	5.5	8.2	9.7	9.1	- -	- -	- -
Renewables[11]	0.0	36.6	36.4	37.5	89.5	83.3	80.5	- -	- -	- -
Other	0.0	0.6	0.6	0.6	0.6	0.6	0.6	- -	- -	- -
Total cumulative additions	**0.0**	**82.7**	**86.7**	**97.2**	**357.6**	**351.5**	**357.1**	**- -**	**- -**	**- -**
Cumulative capacity retirements[13]										
Coal	0.0	43.4	49.9	68.3	44.2	50.8	69.2	- -	- -	- -
Natural gas	0.0	8.1	8.1	8.3	9.4	9.4	9.5	- -	- -	- -
Nuclear / uranium	0.0	4.8	4.8	4.8	4.8	4.8	4.8	- -	- -	- -
Renewables[11]	0.0	0.9	0.9	0.9	0.9	0.9	0.9	- -	- -	- -
Other	0.0	14.3	14.4	15.6	30.1	30.8	32.2	- -	- -	- -
Total cumulative retirements	**0.0**	**71.5**	**78.0**	**97.9**	**89.5**	**96.7**	**116.6**	**- -**	**- -**	**- -**
Liquids from coal (million barrels per day)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	- -	- -	- -

Table D14. Key results and assumptions for coal cost cases (continued)
(million short tons per year, unless otherwise noted)

Supply, disposition, prices, electricity generating capacity, and costs	2012	2020			2040			Annual growth 2012-2040 (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, 2012=1.000)										
Transportation rate multipliers										
Eastern railroads	1.000	0.960	1.022	1.090	0.760	1.008	1.260	-1.0%	0.0%	0.8%
Western railroads	1.000	0.940	1.005	1.070	0.750	0.996	1.250	-1.0%	0.0%	0.8%
Mine equipment costs										
Underground	1.000	0.932	1.000	1.072	0.762	1.000	1.308	-1.0%	0.0%	1.0%
Surface	1.000	0.932	1.000	1.072	0.762	1.000	1.308	-1.0%	0.0%	1.0%
Other mine supply costs										
East of the Mississippi: all mines	1.000	0.932	1.000	1.072	0.762	1.000	1.308	-1.0%	0.0%	1.0%
West of the Mississippi: underground	1.000	0.932	1.000	1.072	0.762	1.000	1.308	-1.0%	0.0%	1.0%
West of the Mississippi: surface	1.000	0.932	1.000	1.072	0.762	1.000	1.308	-1.0%	0.0%	1.0%
Coal mining labor productivity										
(short tons per miner per hour)	5.19	5.52	4.64	3.85	6.89	3.68	1.68	1.0%	-1.2%	-4.0%
Average coal miner wage										
(2012 dollars per year)	80,450	87,295	93,666	100,431	79,835	104,525	136,440	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. Prices weighted by production, which differs from average minemouth prices published in EIA data reports where it is weighted by reported sales.
[8]Prices weighted by consumption tonnage; weighted average excludes export free-alongside-ship prices.
[9]Free-alongside-ship price at U.S. port of exit.
[10]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.
[11]Includes conventional hydroelectric, geothermal, wood, wood waste, municipal waste, landfill gas, other biomass, solar, and wind power. Facilities co-firing biomass and coal are classified as coal.
[12]Cumulative additions after December 31, 2012. Includes all additions of electricity-only and combined heat and power plants projected for the electric power, industrial, and commercial sectors.
[13]Cumulative retirements after December 31, 2012. Includes retirements of electricity-only and combined heat and power plants that have a regulatory status.
- - = Not applicable.
Btu = British thermal unit.
IGCC = Integrated coal-gasification combined cycle.
Note: Totals may not equal sum of components due to independent rounding. Data for 2012 are model results and may differ from official EIA data reports.
Sources: 2012 data based on: U.S. Energy Information Administration (EIA), *Annual Coal Report 2012*, DOE/EIA-0584(2012) (Washington, DC, December 2013); EIA, *Quarterly Coal Report, October-December 2012*, DOE/EIA-0121(2012/4Q) (Washington, DC, March 2013); U.S. Department of Labor, Bureau of Labor Statistics, Quarterly Census of Employment and Wages: Coal Mining, Series ID: ENUUS0005052121; and EIA, AEO2014 National Energy Modeling System run REF2014.D102413A.
Projections: EIA, AEO2014 National Energy Modeling System runs LCCST14.D120413A, REF2014.D102413A, and HCCST14.D120413A.

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Appendix E
NEMS overview and brief description of cases

The National Energy Modeling System

Projections in the *Annual Energy Outlook 2014* (AEO2014) are generated using the National Energy Modeling System (NEMS) [*1*], 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 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 nongovernment groups, such as the Electric Power Research Institute, Duke University, and Georgia Institute of Technology. In addition, AEO projections are used by analysts and planners in other government agencies and nongovernmental 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 across 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 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, thereby achieving an economic equilibrium of supply and demand in the consuming sectors. A solution is reached for each year from 2013 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 effects and costs of legislation and environmental regulations that affect each 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 AEO2014 generally represents current legislation and environmental regulations, including recent government actions for which implementing regulations were available as of October 31, 2013, as discussed in the Legislation and Regulations section of the AEO. The potential effects 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 are examined, however, in alternative cases included in AEO2014 or in other analysis completed by EIA.

In general, the historical data presented with AEO2014 projections are based on various EIA publications [*2*]; however, data were taken from multiple sources. Historical numbers are presented for comparison only and may be estimates. Source documents should be consulted for the official data values. Footnotes to AEO2014 appendix tables indicate the definitions and sources of historical data.

Where possible AEO2014, which was developed during the summer of 2013, presents information for 2013 and 2014 that is consistent with the short-term projections from EIA's September 2013 *Short-Term Energy Outlook* (STEO) [*3*]. EIA's views regarding energy use over the 2013 through 2015 period are reported in monthly STEO updates [*4*], which should be considered to supersede information reported for those years in AEO2014.

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, values 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 Industrial Output model, and National Employment by Industry Model. In addition, EIA has constructed a Regional Economic, Industrial Output and Employment by Industry model to project regional economic drivers, and a Commercial Floorspace model to project 13 floorspace types in the nine 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. This module 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 assumptions for petroleum products for import and export in the United States. The IEM, through interaction with the rest of NEMS, changes North Sea Brent and West Texas Intermediate (WTI) prices in response to changes in expected production and consumption of crude-like 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 projections of 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 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 other 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. AEO2014 includes an upgraded representation for the glass 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 technological change in the glass industry to be modeled endogenously, using a more detailed process flow 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 industries and aluminum industry were upgraded to process flow models in previous AEOs. The iron and steel and paper industries will be similarly upgraded in future AEOs.

Model input data associated with energy intensity were aligned with the Manufacturing Energy Consumption Survey 2010 data. In the bulk chemicals model, behavior of naphtha and ethane prices was modified to better respond to oil price cases. The cement model was modified to include multichannel burners that add flexibility for fuel mix, allowing the use of significant amounts of secondary fuels, such as alternative solid fuels including tires, plastics, wood, and waste. The model also includes more rapid penetration of energy-efficient grinding. In the food industry, shipments were categorized in more detail, to grain and oil seed milling, dairy, animal slaughter, and all other. Changes also were made to the nonmanufacturing data approach. Census, U.S. Department of Agriculture, and EIA's Fuel Oil Kerosene Sales data were used to improve projections of petroleum product and natural gas consumption in agriculture, construction, and mining. CHP use is now differentiated by region and industry, based on EIA's updated historical data.

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 and consumer behavior. 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 greenhouse gas (GHG) emissions standards, heavy-duty vehicle (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. Freight ton-miles and efficiency also are projected in the model.

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. This 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 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 AEO2014. The AEO2014 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 Assembly Bill 32, the Global Warming Solutions Act of 2006 (AB 32). The AEO2014 Reference case leaves the Clean Air Interstate Rule (CAIR) in effect after the court vacated the Cross-State Air Pollution Rule 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 fuel 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 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 AEO2014 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% 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% 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. They provide a credit of up to 2.3 cents/kilowatthour (kWh) for electricity produced in the first 10 years of plant operation. For AEO2014, EIA represents the expiration of the PTC that occurred at the end of 2013. However, because the expiration date reflects an under-construction versus in-service deadline, the effective modeled eligibility deadline is extended to new wind and landfill gas plants coming online by the end of 2015, and to other eligible plants coming online by the end of 2016. AEO2014 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 2014 [5].

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 geologic formations. 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 six onshore, three offshore, and in three Alaska 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 plays. Crude oil resources include structurally reservoired resources (i.e., conventional) 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 volumes are used as inputs to the LFMM 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 balances natural gas supply and demand, tracks the flows of natural gas, and determines the associated capacity expansion requirements in an aggregate pipeline network, connecting domestic and limited foreign supply sources with 12 lower 48 states regions. The 12 lower 48 states regions align with the nine 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. The primary outputs of the module are delivered natural gas prices by region and sector, supply prices, and realized domestic natural gas production. The module also projects natural gas 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/export activity, and domestic refinery operations, subject to demand for petroleum products, availability and price of imported petroleum, environmental regulations, 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 [6] are reviewed and updated annually.

The module represents refining activities in eight 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 are 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 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% by volume (E10), 15% by volume (E15) in states that lack explicit language capping ethanol volume or oxygen content, and up to 85% by volume (E85) for use in flex-fuel vehicles. The module also includes a 16% by volume biobutanol/gasoline blend. Crude oil and refinery product imports are represented by supply curves defined by the NEMS IEM. Products also can be imported from refining region nine (Maritime Canada/Caribbean). Refinery product exports are represented by demand curves, also 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 175 are now in operation, with a total maximum sustainable nameplate capacity of more than 13 billion gallons annually), and are based on a well-known technology that converts starch and sugar into ethanol. Ethanol from cellulosic sources is a new technology with only a few small pilot plants in operation. Ethanol from advanced feedstocks—produced at ethanol refineries that ferment and distill grains other than corn, and reduce GHG emissions by at least 50%—is another new technology modeled in the LFMM. The LFMM also has the capability to produce biobutanol from a retrofitted corn ethanol facility, if economically competitive.

Fuels produced by Fischer-Tropsch synthesis and through a pyrolysis process are also modeled in the LFMM, based on their economics compared with 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/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 mining capacity, capacity utilization of mines, 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 coal import demands, subject to constraints on export capacities and trade flows. The international coal market component of the module computes trade in two types of coal (steam and metallurgical) 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 2014 cases

Table E1 provides a summary of the cases produced as part of AEO2014. For each case, the table gives the name used in AEO2014, 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 2014 [7]. Regional results and other details of the projections are available at http://www.eia.gov/forecasts/aeo/tables_ref.cfm#supplement.

Macroeconomic growth cases

In addition to the AEO2014 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 0.7%/year, nonfarm employment by 0.8%/year, and labor productivity by 1.8%/year from 2012 to 2040. Economic output as measured by real GDP increases by 2.4%/year from 2012 through 2040, and growth in real disposable income per capita averages 1.7%/year.

Table E1. Summary of the AEO2014 cases

Case name	Description	Reference in text	Reference in Appendix E
Reference	Real GDP grows at an average annual rate of 2.4% from 2012 to 2040. Crude oil prices rise to about $141/barrel (2012 dollars) in 2040. Complete projection tables in Appendix A.	--	--
Low Economic Growth	Real GDP grows at an average annual rate of 1.9% from 2012 to 2040. Other energy market assumptions are the same as in the Reference case. Partial projection tables in Appendix B.	p. MT-2	p. E-8
High Economic Growth	Real GDP grows at an average annual rate of 2.8% from 2012 to 2040. Other energy market assumptions are the same as in the Reference case. Partial projection tables in Appendix B.	p. MT-2	p. E-9
Low Oil Price	Low prices result from a combination of low demand for petroleum and other liquids in the non-Organization for Economic Cooperative Development (non-OECD) nations and higher global supply. Lower demand is measured by lower economic growth relative to the Reference case. On the supply side, the Organization of the Petroleum Exporting Countries (OPEC) increases its market share to 51%, and the costs of other liquids production technologies are lower than in the Reference case. Light, sweet crude oil prices fall to $70/barrel in 2017 and rise slowly to $75/barrel in 2040. Partial projection tables in Appendix C.	p. MT-3	p. E-9
High Oil Price	High prices result from a combination of higher demand for liquid fuels in non-OECD nations and lower global supply. Higher demand is measured by higher economic growth relative to the Reference case. OPEC market share averages 37% throughout the projection. Non-OPEC petroleum production expands more slowly in the short to middle term relative to the Reference case. Crude oil prices rise to $204/barrel (2012 dollars) in 2040. Partial projection tables in Appendix C.	p. MT-3	p. E-9
No Sunset	Begins with the Reference case and assumes extension of all existing tax credits and policies 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. Also includes extension of the $1.01/gallon ethanol subsidy and $1.00/gallon biodiesel subsidy to the end of the projection period. Partial projection tables in Appendix D.	p. IF-3	p. E-10
Extended Policies	Begins with the No Sunset case but excludes extension of the ethanol and biofuel subsidies that were included in the No Sunset case. Assumes an increase in the capacity limitations on the ITC for CHP 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 and HDV fuel economy standards in the transportation sector. Partial projection tables in Appendix D.	p. IF-3	p. E-10
High Rail LNG	Assumes a higher LNG locomotive penetration rate into motive stock such that 100% of locomotives are LNG capable by 2037. Partial projection tables in Appendix D.	p. IF-18	p. E-11
Low Rail LNG	Assumes a lower LNG locomotive penetration rate into motive stock, at a 1.0 average annual turnover rate for dual-fuel engines that can use up to 80% LNG. Partial projection tables in Appendix D.	p. IF-18	p. E-11
High VMT	Assumes higher licensing rates and travel demand for specific age and gender cohorts. Vehicle miles traveled per licensed driver in 2012 is 3% higher than in the Reference case, increasing to 7% higher in 2027, and then declining to 3% above the Reference case in 2040. Partial projection tables in Appendix D.	p. IF-22	p. E-11
Low VMT	Assumes lower licensing rates and travel demand for specific age and gender cohorts. Vehicle miles traveled per licensed driver is 5% lower than in the Reference case for the full projection. Licensing rates stay constant at 2011 levels or decline from 2011 to 2040, specific to gender, age, and census division categories. Partial projection tables in Appendix D.	p. IF-22	p. E-11

Table E1. Summary of the AEO2014 cases (continued)

Case name	Description	Reference in text	Reference in Appendix E
Accelerated Nuclear Retirements	Assumes that all nuclear plants are limited to a 60-year life, uprates are limited to the 0.7 gigawatts (GW) that have been reported to EIA, and no new additions beyond those planned in the Reference case. Nonfuel operating costs for existing nuclear plants are assumed to increase by 3%/year after 2013. Partial projection tables in Appendix D.	p. IF-35	p. E-11
Accelerated Coal Retirements	Begins with the AEO2014 High Coal Cost case assumptions and also assumes that nonfuel operating costs for existing coal plants increase by 3%/year after 2013. Partial projection tables in Appendix D.	p. IF-35	p. E-12
Accelerated Nuclear and Coal Retirements	Combines the assumptions in the Accelerated Nuclear Retirements and Accelerated Coal Retirements cases. Partial projection tables in Appendix D.	p. IF-35	p. E-12
Electricity: Low Nuclear	Begins with the Accelerated Nuclear Retirements case and combines with assumptions in the High Oil and Gas Resource and the No Sunset cases. Partial projection tables in Appendix D.	p. MT-19	p. E-12
Electricity: High Nuclear	Assumes that all nuclear plants are life-extended beyond 60 years (except for 4.8 GW of announced retirement), and a total of 6.0 GW of uprates. 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. MT-19	p. E-12
Renewable Fuels: Low Renewable Technology Cost	Capital costs for new nonhydro renewable generating technologies are 20% lower than Reference case levels through 2040, and biomass feedstocks are 20% less expensive for a given resource quantity. Capital costs for new ethanol, biodiesel, pyrolysis, and other BTL production technologies are 20% lower than Reference case levels through 2040, and the industrial sector assumes a higher rate of recovery for biomass byproducts from industrial processes. Partial projection tables in Appendix D.	p. MT-8	p. E-12
Oil and Gas: Low Oil and Gas Resource	Estimated ultimate recovery per shale gas, tight gas, and tight oil well is 50% lower than in the Reference case. All other resource assumptions remain the same as in the Reference case. Partial projection tables in Appendix D.	p. IF-12	p. E-12
Oil and Gas: High Oil and Gas Resource	Estimated ultimate recovery per shale gas, tight gas, and tight oil well is 50% higher and well spacing is 50% lower (or the number of wells left to be drilled is 100% higher) than in the Reference case. In addition, tight oil resources are added to reflect new plays or the expansion of known tight oil plays and the estimated ultimate recovery for tight and shale wells increases 1%/year to reflect additional technological improvement. Also includes kerogen development, tight oil resources in Alaska, and 50% higher undiscovered resources in the offshore lower 48 states, Alaska, and shale gas in Canada than in the Reference case. Partial projection tables in Appendix D.	p. IF-12	p. E-13
Coal: Low Coal Cost	Regional productivity growth rates for coal mining are approximately 2.3 percentage points per year higher than in the Reference case, and coal miner wages, mine equipment costs, and coal transportation rates are lower than in the Reference case, falling to about 25% below the Reference case in 2040. The price change for non-U.S. export supplies is assumed to be roughly 10% less than the price change projected for U.S. coal exports. Partial projection tables in Appendix D.	p. MT-32	p. E-13
Coal: High Coal Cost	Regional productivity growth rates for coal mining are approximately 2.3 percentage points per year lower than in the Reference case, and coal miner wages, mine equipment costs, and coal transportation rates are higher than in the Reference case, ranging between 24% and 31% above the Reference case in 2040. The price change for non-U.S. export supplies is assumed to be roughly 10% less than the price change projected for U.S. coal exports. Partial projection tables in Appendix D.	p. MT-32	p. E-13
Integrated 2013 Demand Technology	Referred to in the text as 2013 Demand Technology. Assumes that future equipment purchases in the residential and commercial sectors are based only on the range of equipment available in 2013. Commercial and existing residential building shell efficiency is held constant at 2013 levels. Energy efficiency of new industrial plant and equipment is held constant at the 2014 level over the projection period. Partial projection tables in Appendix D.	p. MT-6	p. E-9

Table E1. Summary of the AEO2014 cases (continued)

Case name	Description	Reference in text	Reference in Appendix E
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. All residential building shells for new construction are assumed to be code compliant and built to the most efficient specifications after 2013, and existing residential shells have twice the improvement of the Reference case. New and existing commercial building shell efficiencies improve 50% 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. MT-6	p. E-9
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 code compliance is assumed to improve after 2013, and building shell efficiencies are assumed to meet ENERGY STAR requirements by 2023. Existing residential building shells exhibit 50% more improvement than in the Reference case after 2013. New and existing commercial building shells are assumed to improve 25% more than in the Reference case by 2040. 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, as well as battery electric vehicle costs. Freight trucks are assumed to see more rapid improvement in fuel efficiency. More optimistic assumptions for fuel efficiency improvements are also made for the air, rail, and shipping sectors. Partial projection tables in Appendix D.	p. MT-6	p. E-9
Energy Savings and Industrial Competitiveness Act	Begins with the Reference case and assumes passage of the energy efficiency provisions in S. 1392, including appropriation of funds at the levels authorized in the bill. Key provisions modeled include improved national building codes for new homes and commercial buildings and a rebate program for advanced industrial motor systems, assuming the bill's passage in 2014. For new residential construction, building shell efficiencies are assumed to improve by 15% relative to IECC2009 by 2020, and building code compliance is assumed to improve. New commercial building shells are assumed to be 30% more efficient than ASHRAE 90.1-2004 by 2020. Partial projection tables in Appendix D.	p. IF-6	--
Low Electricity Demand	This case was developed to explore the effects on the electric power sector if growth in sales to the grid remained relatively low. Begins with the Best Available Demand Technology case, which lowers demand in the building sectors, and also assumes greater improvement in industrial motor efficiency. Partial projection tables in Appendix D.	p. IF-46	p. E-12
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. MT-33	p. E-14
GHG10	Applies a price for CO2 emissions throughout the economy, starting at $10/metric ton in 2015 and rising by 5%/year through 2040. Partial projection tables in Appendix D.	p. MT-34	p. E-14
GHG25	Applies a price for CO2 emissions throughout the economy, starting at $25/metric ton in 2015 and rising by 5%/year through 2040. Partial projection tables in Appendix D.	p. MT-34	p. E-14
GHG10 and Low Gas Prices	Combines GHG10 and High Oil and Gas Resource cases. Partial projection tables in Appendix D.	p. MT-34	p. E-14

- The Low Economic Growth case assumes lower growth rates for population (0.6%/year) and labor productivity (1.4%/year), resulting in lower nonfarm employment (0.7%/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%/year from 2012 through 2040, and growth in real disposable income per capita averages 1.3%/year.
- The High Economic Growth case assumes higher growth rates for population (0.8%/year) and labor productivity (2.0%/year), resulting in higher nonfarm employment (1.0%/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 (2.8%/year) than in the Reference case (2.4%). Disposable income per capita grows by 1.7%/year, the same as in the Reference case.

Oil price cases

The benchmark oil price is the price for Brent crude oil, which better reflects the marginal price paid by refineries for imported light, sweet crude oil used to produce petroleum products for consumers. EIA continues to report the WTI price and 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. AEO2014 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 primarily from variation in demand for petroleum and other liquid fuels in non-OECD countries due to different levels of economic growth. The Low and High Oil Price cases also reflect different assumptions about decisions by members of OPEC regarding the preferred rate of oil production and about the future finding and development costs and accessibility of non-OPEC oil resources.

- In the Reference case, real oil prices (in 2012 dollars) rise from $112/barrel in 2012 to $141/barrel in 2040. The Reference case represents EIA's current judgment regarding exploration and development costs and accessibility of oil resources. Compared with AEO2013, EIA sees increasing production from non-OPEC countries, particularly the United States. However, EIA 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 oil production will represent between 39% and 44% of the world's total petroleum and other liquids production over the projection period.
- In the Low Oil Price case, crude oil prices fall to $70/barrel (2012 dollars) in 2016, remain below $70/barrel through 2023, and stay below $75/barrel through 2040. The low price results from lower costs of production and lower demand from China and the Middle East compared with the Reference case. Crude oil production from across OPEC rises throughout the projection period in this case, displacing more expensive crude projected in the Reference case (including from the United States). Correspondingly, OPEC's market share of petroleum rises steadily from 40% through 2015 to almost 53% in 2040. In addition, in this case, bitumen production in Canada and renewable fuels from Brazil and the United States see decreases in costs, leading to increased production. This keeps the OPEC market share to between 39% and 50% of the total liquids market. With the exceptions of China and the Middle East, which see reduced economic growth in this case, the lower prices generally lead to higher demand than projected in the Reference case.
- In the High Oil Price case, oil prices reach about $205/barrel (2012 dollars) in 2040. The high prices result primarily from higher costs of petroleum supply. Fewer structurally reservoired crude oil supplies are developed than in the Reference case, leading to increased development of more costly resources, including tight oil and bitumen. Higher prices also lead to significant increases in renewable liquid fuels and coal-to-liquid products as compared with the Reference case. In this case, OPEC's share of world liquids production never exceeds the high of 40% that it reaches in 2013 and drops as low as 36%. The higher supply costs depress demand globally through 2028, but stronger growth in non-OECD countries than is projected in the Reference case leads to higher demand than in the Reference case, starting in these countries in 2029, and starting globally in 2037.

Buildings sector cases

In addition to the AEO2014 Reference case, three technology-focused cases using the NEMS Demand Modules were developed to examine the effects of changes in technology. Residential sector assumptions for the technology-focused cases are as follows:

- The Integrated 2013 Demand Technology case assumes that all future residential equipment purchases are limited to the range of equipment available in 2013. Existing building shell efficiencies are assumed to be fixed at 2013 levels (no further improvements). For new construction, building shell assumptions are the same as in the Reference case.
- The Integrated High Demand Technology case assumes that residential advanced equipment is available earlier, at lower costs, and/or at higher efficiencies [8]. Existing building shell efficiencies exhibit 50% more improvement than in the Reference case after 2013. For new construction, building code compliance is assumed to improve after 2013, and building shell efficiencies are assumed to meet ENERGY STAR requirements by 2023. Consumers evaluate investments in energy efficiency at a 7% 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 2013. For new construction, 100% compliance with building codes is assumed, and building shell efficiencies are assumed to meet the criteria for the most efficient components after 2013. Consumers evaluate investments in energy efficiency at a 7% real discount rate.

Commercial sector assumptions for the technology-focused cases are as follows:

- The Integrated 2013 Demand Technology case assumes that all future commercial equipment purchases are limited to the range of equipment available in 2013. Building shell efficiencies are assumed to be fixed at 2013 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% real discount rate. For new and existing buildings in 2040, building shell efficiencies are assumed to show 25% 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% real discount rate. For new and existing buildings in 2040, building shell efficiencies are assumed to show 50% 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 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% below Reference case assumptions from 2014 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, as well as tax credits for energy-efficient homes and selected residential appliances. For the commercial sector, business ITC 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% level without reverting to 10% as scheduled.
- The Extended Policies case includes updates to federal appliance standards, as prescribed by the timeline in DOE's multiyear 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 AEO2014 Reference case and purchasing specifications for federal agencies designated by the Federal Energy Management Program. The case also adds two additional rounds of improved national building codes with full implementation in 2023 and 2029.

Industrial sector cases

In addition to the AEO2014 Reference case, two technology-focused cases developed using the IDM of NEMS 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 2013 Demand Technology case and Integrated High Demand Technology case. For the industrial sector, assumptions for the two technology-focused cases are as follows:

- For the Integrated 2013 Demand Technology case, the energy efficiency of new industrial plant and equipment is held constant at the 2014 level over the projection period. Changes in aggregate energy intensity may result both from changing equipment and production efficiency and from changing the composition of output within an individual industry. Because all AEO2014 side cases are integrated runs, potential feedback effects from energy market interactions are captured. Therefore, 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 [9] and a more rapid rate of improvement in the recovery of biomass byproducts from industrial

processes—i.e., 0.7%/year as compared with 0.4%/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% 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 (MW) to 25 MW and eliminating the system-wide cap of 50 MW. These assumptions are based on the proposals made in H.R. 2750 and H.R. 2784 of the 112th Congress.

Transportation sector cases

In addition to the AEO2014 Reference case, the NEMS Transportation Demand Module was used as part of six AEO2014 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. 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, including battery electric systems. In the freight truck sector, the Integrated High Demand Technology case assumes more rapid incremental improvement in fuel efficiency. 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 1.3% through 2040, reaching a combined average LDV fuel economy compliance of 55.7 miles/gallon in 2040. As part of the Extended Policies case, the Transportation Demand Module was also used to examine the effects of extending and enhancing the HDV fuel consumption and GHG emissions standards through 2040. The regulations are currently specified for model year (MY) 2014 to MY 2018. The Extended Policies case includes a modest increase in fuel consumption and GHG emissions standards for 13 HDV vehicle size classes.

Assumptions in the NEMS Transportation Demand Module were modified for the High Vehicle Miles Traveled (VMT) and Low VMT cases. These cases examine the effects of changes to licensing rates and VMT on the LDV transportation sector. The High VMT case includes assumptions for increases in VMT per licensed driver for the five VMT age cohorts. VMT per licensed driver is 3% higher than in the Reference case in 2012, increases to 7% above the Reference case in 2027, and decreases back to 3% above the Reference case by 2040. The Low VMT case includes assumptions for a decline in licensed drivers for the 13 gender/age cohorts, as well as decreases in VMT per licensed driver for the five VMT age groups. VMT per licensed driver are 5% lower than in the Reference case for the entire projection, and the licensing rates either stay constant at 2011 levels for all age cohorts or decline as portrayed in the Reference case.

The Transportation Demand Module was also used to examine the effect of varying LNG locomotive penetration in the freight rail sector. The High Rail LNG case allows for LNG locomotives to penetrate the rail sector fully by 2037. The Low Rail LNG case incorporates dual-fuel engines that utilize LNG up to 80%, with an LNG locomotive penetration rate at 1.0% of the average annual stock turnover.

Electricity sector cases

In addition to the Reference case, several integrated cases with alternative electric power assumptions were developed to support discussions in the Market Trends and Issues in Focus sections of AEO2014. Three alternative cases were run to examine the impacts on the electric power sector of potentially large retirements of baseload coal and nuclear plants. In recent years, a combination of low natural gas prices, high retrofit or repair costs, and uncertainty about environmental legislation have led to an increase in announced retirements of coal and nuclear plants. The Issues in Focus article, “Implications of accelerated power plant retirements,” discusses the factors influencing those retirement decisions, using the analysis cases to illustrate potential impacts. Two additional cases for nuclear power plants were developed to address uncertainties about the operating lives of existing reactors and the potential for new nuclear capacity and for capacity uprates at existing plants.

A final case combines technology and efficiency improvements across the end-use demand sectors to create a case that projects relatively low growth in total electricity consumption. The Issues in Focus article, “Implications of low electricity demand growth,” analyzes the impacts on power sector capacity and generation requirements under a scenario of low demand growth.

Accelerated Retirement cases

- The Accelerated Nuclear Retirement case assumes that reactors will not receive second license renewals, so that all existing nuclear plants are retired within 60 years after beginning operation. The 4.8 GW of announced retirements remain as in the

Reference case, along with the decrease of 5.7 GW of nuclear capacity by 2020 to reflect plants at risk of early closure in specific regions. In the Reference case, after 2020, existing plants are assumed to run as long as they continue to be economic, implicitly assuming that a second 20-year license renewal will occur for most plants that reach 60 years of operation before 2040. In the Accelerated Nuclear Retirement case, an additional 37 GW of nuclear capacity is retired by 2040. The Accelerated Nuclear Retirement case also assumes that no new nuclear capacity is added throughout the projection, excluding capacity already planned and under construction. It assumes that only those capacity uprates already reported to EIA (0.7 GW) are completed, as in the Reference case, and that nonfuel operating costs at existing nuclear plants increase by 3%/year after 2013.

- The Accelerated Coal Retirement case includes the assumptions used for the High Coal Cost case, including lower productivity and higher costs associated with mining and coal transportation rates. In 2040, delivered coal prices are more than 60% higher in the Accelerated Coal Retirement case than in the Reference case. This case also assumes that non-fuel operating costs at existing coal plants increase by 3%/year after 2013.
- The Accelerated Coal and Nuclear Retirement case combines the assumptions of the Accelerated Coal Retirement and Accelerated Nuclear Retirement cases.

Nuclear cases

- The Low Nuclear case combines the Accelerated Nuclear Retirement case with the High Oil and Gas Resource case and the No Sunset case. This combines more pessimistic assumptions for nuclear costs and lifetimes with more favorable conditions for natural gas-fired and renewable technologies, so that the impacts on the power sector can be viewed under an outlook where output from nuclear power is greatly reduced.
- The High Nuclear case was run to provide a more optimistic outlook, with all nuclear power plant licenses renewed and all plants continuing to operate economically beyond 60 years (excluding the 4.8 GW of announced retirements). The High Nuclear case also assumes that additional planned nuclear capacity is completed, based on combined license applications (COL) issued by the NRC and whether an Atomic Safety and Licensing Board hearing has been scheduled for a COL. The High Nuclear case assumes 12.6 GW of planned capacity additions, as compared with 5.5 GW of planned capacity additions assumed in the Reference case. Finally, the High Nuclear case assumes a total of 6.0 GW of uprates at existing plants, reflecting an assumption that most plants with remaining uprate potential will elect to perform such uprates.

Low Electricity Demand case

- The Low Electricity Demand case uses the assumptions in the Best Available Demand Technology case for the residential and commercial sectors. In addition, input values for the industrial sector motor model are adjusted to increase system savings values for pumps, fans, and air compressors relative to the Reference case. This adjustment lowers total motor electricity consumption by slightly less than 20%. Although technically plausible, this decrease in motor adjustment is not intended to be a likely representation of motor development. As a result of these changes across the end-use sectors, retail sales in 2040 in this case are roughly the same as in 2012.

Renewable fuels cases

In addition to the AEO2014 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 capital costs of new non-hydro renewable generating technologies are assumed to be 20% below Reference case assumptions from 2014 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% 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. Capital costs for new ethanol, biodiesel, pyrolysis, and other BTL production technologies also are 20% lower than Reference case levels through 2040.
- 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 2.3 cents/kWh (adjusted annually for inflation) 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/kWh 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 2.3 cents/kWh. The extension also applies to the 30% ITC for new generators using solar energy, which may also be claimed in lieu of the PTC for eligible technologies.

Oil and natural gas supply cases

The sensitivity of the AEO2014 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 effects 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 estimated ultimate recovery per tight oil, tight gas, or shale gas well is assumed to be 50% lower than in the Reference case, increasing the per-unit cost of developing the resource. The total unproved technically recoverable resource of crude oil is decreased to 180 billion barrels, and the natural gas resource is decreased to 1,480 trillion cubic feet (Tcf), as compared with unproved resource estimates of 209 billion barrels of crude oil and 1,932 Tcf of natural gas as of January 1, 2012, in the Reference case.
- In the High Oil and Gas Resource case, the resource assumptions are adjusted to allow a continued increase in domestic crude oil production, to more than 13 million barrels per day (MMbbl/d) in 2040 compared with 7.5 MMbbl/d in the Reference case. This case includes: (1) 50% higher estimated ultimate recovery per tight oil, tight gas, or shale gas well, with 50% lower acre spacing (minimum 40 acres) than in the Reference case, as well as additional unidentified tight oil resources to reflect the possibility that additional layers or new areas of low-permeability zones will be identified and developed; (2) diminishing returns on the estimated ultimate recovery once drilling levels in a county exceed the number of potential wells assumed in the Reference case to reflect well interference at greater drilling density; (3) additional 1% annual increase in the estimated ultimate recovery for tight oil, tight gas, and shale gas wells due to faster technological improvement; (4) kerogen development reaching 135,000 barrels/day in 2024; (5) tight oil development in Alaska, increasing the total Alaska technically recoverable resource by 1.9 billion barrels; and (6) 50% higher technically recoverable undiscovered resources in Alaska, the offshore lower 48 states, and shale gas in Canada than in the Reference case. Additionally, a few offshore Alaska fields are assumed to be discovered and developed earlier than in the Reference case. The total unproved technically recoverable resource of crude oil increases to 401 billion barrels, and the natural gas resource increases to 3,349 Tcf as compared with unproved resource estimates of 209 billion barrels of crude oil and 1,932 Tcf of natural gas in the Reference case as of the start of 2012.

Liquids market cases

The Liquid Fuels Market Module of NEMS was used (with other NEMS models) to complete the Low Renewable Technology Cost case, which is discussed in more detail in the renewable fuels cases section. In addition to the 20% reduction in nonhydro renewable generating technologies, 20% reduction in biomass feedstock costs, and higher rate of recovery for biomass byproducts from industrial processes, the LFMM assumes capital costs for new ethanol, biodiesel, pyrolysis, and other BTL technologies are 20% lower than reference case levels through 2040.

Some assumptions in the LFMM were changed to support the No Sunset case by extending the ethanol and biodiesel subsidies beyond their current end dates (2013). This assumption was excluded from the Extended Policies 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, coal transportation rates, and costs of non-U.S. coal supplies to international markets. The alternative productivity and cost assumptions are applied in every year from 2014 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 2.4 percentage points observed since 2000 for mines in Wyoming's Powder River Basin and 2.3 percentage points 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% change in rates relative to the Reference case in 2040. In both the High and Low Coal Cost cases, price trends for non-U.S. coal export supplies (e.g., coal exported to international markets from ports in Australia or Southern Africa, a NEMS-defined region that includes South Africa, Mozambique, and Botswana) are assumed to be similar, but price changes are approximately 10% less than the price changes projected for U.S. coal exports. 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 -1.5% in the Reference case for the years 2014 through 2040 to 0.9% in the Low Coal Cost case. Coal miner wages, mine equipment costs, and other mine supply costs all are assumed to be about 24% 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% lower in 2040. In the international coal market, the price change for non-U.S. export supplies is assumed to be roughly 10% less than the price change projected for U.S. coal exports.
- 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 miner wages, mine equipment costs, and other mine supply costs in 2040 are assumed to be about 31% higher than in the Reference case, and coal transportation rates in 2040 are assumed to be 25% higher. In the international coal market, the price change for non-U.S. export supplies is assumed to be roughly 10% less than the price change projected for U.S. coal exports.

Additional data on productivity, wage, mine equipment cost, and coal transportation rate assumptions for the Reference and alternative coal cost cases are included in Appendix D.

Cross-cutting integrated cases

A series of cross-cutting integrated cases are used in AEO2014 to analyze specific cases with broader sectoral impacts. For example, three integrated technology progress cases analyze the effects of faster and slower technology improvement in the demand sectors (partially described in the sector-specific sections above). In addition, four cases were run with alternative assumptions about expectations for 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 2013 Demand Technology, Integrated Best Available Demand Technology, and Integrated High Demand Technology—are used in AEO2014 to examine the potential effects of variation in the rate of technology improvement in the end-use demand sectors, independent of any offsetting effects 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 AEO2014 Reference case, a No Sunset case was run, assuming the extension of all existing tax credits and policies 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. The No Sunset case also includes extension of the $1.01/gallon ethanol subsidy and $1.00/gallon biodiesel subsidy to the end of the projection period. Specific assumptions for each end-use sector and for renewables are described in the sector-specific sections above.

Extended Policies case

The Extended Policies case begins with the No Sunset case described above but excludes extension of the ethanol and biofuel subsidies included in the No Sunset case, because the RFS program already included in the AEO2014 Reference case tends to determine the levels of ethanol and biodiesel use. The Extended Policies case assumes an increase in the capacity limitations on the ITC and extension of the program. It includes additional rounds of federal 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 2029; and increases LDV and HDV fuel economy standards in the transportation sector. 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 and CTL plants without CCS and for all capital investment projects (excluding CCS) at existing coal-fired power plants in the Reference case and all other AEO2014 cases except the No GHG Concern case, GHG10 case, GHG25 case, and GHG10 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 four 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 a specific economywide carbon emission price and low natural gas price. AEO2014 includes three economywide CO_2 price cases—two levels of carbon prices and one case combined with an alternative natural gas price projection. In the GHG10 case and the GHG10 and Low Gas Prices case, the price of carbon emissions is set at $10/metric ton of CO_2 in 2015. In the GHG25 case, the price is set at $25/metric ton of CO_2 in 2015. In all cases, the price begins to rise in 2016 at 5%/year. The GHG10 case and the GHG25 case use the Reference case assumptions regarding oil and natural gas resource availability. The GHG10 and Low Gas Prices case uses the assumptions from the High Oil and Gas Resource case, as described above in the Oil and natural gas supply section. The GHG cases are intended to measure the sensitivity of the AEO2014 projections to a range of implicit or explicit valuations of CO_2 emissions. At the time AEO2014 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 AEO2014, 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

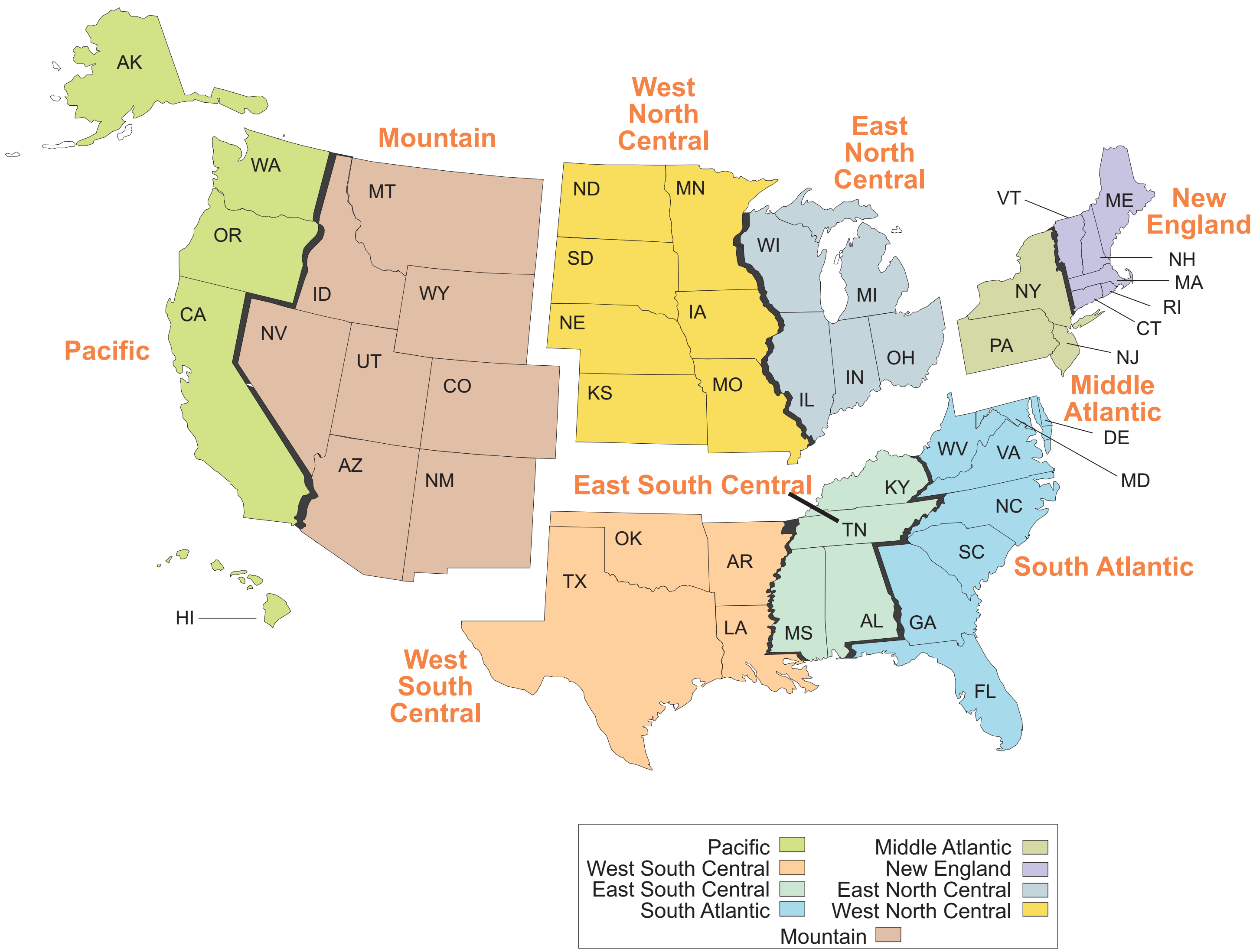
Links current as of April 2014

1. U.S. Energy Information Administration, *The National Energy Modeling System: An Overview 2009,* DOE/EIA-0581(2009) (Washington, DC, October 2009), http://www.eia.gov/oiaf/aeo/overview.
2. Selected EIA publications used for data sources include *Monthly Energy Review, Natural Gas Annual, Natural Gas Monthly, Electric Power Monthly, Electric Power Annual, Annual Coal Report, Petroleum Supply Annual,* and *Quarterly Coal Report,* as well as EIA surveys.
3. U.S. Energy Information Administration, *Short-Term Energy Outlook September 2013* (Washington, DC, September 2013), http://www.eia.gov/forecasts/steo/archives/Sep13.pdf. Portions of the preliminary information were also used to initialize the NEMS Liquids Fuels Market Module projection.
4. U.S. Energy Information Administration, *Short-Term Energy Outlook* (Washington, DC, January 2014), http://www.eia.gov/forecasts/steo/outlook.cfm.
5. U.S. Energy Information Administration, *Assumptions to the Annual Energy Outlook 2014,* DOE/EIA-0554(2014) (Washington, DC, April 2014), http://www.eia.gov/forecasts/aeo/assumptions.
6. Alternative technologies for other liquids include all biofuels technologies plus CTL and GTL.
7. U.S. Energy Information Administration, *Assumptions to the Annual Energy Outlook 2014,* DOE/EIA-0554(2014) (Washington, DC, April 2014), http://www.eia.gov/forecasts/aeo/assumptions.
8. 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).
9. 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).

Appendix F

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

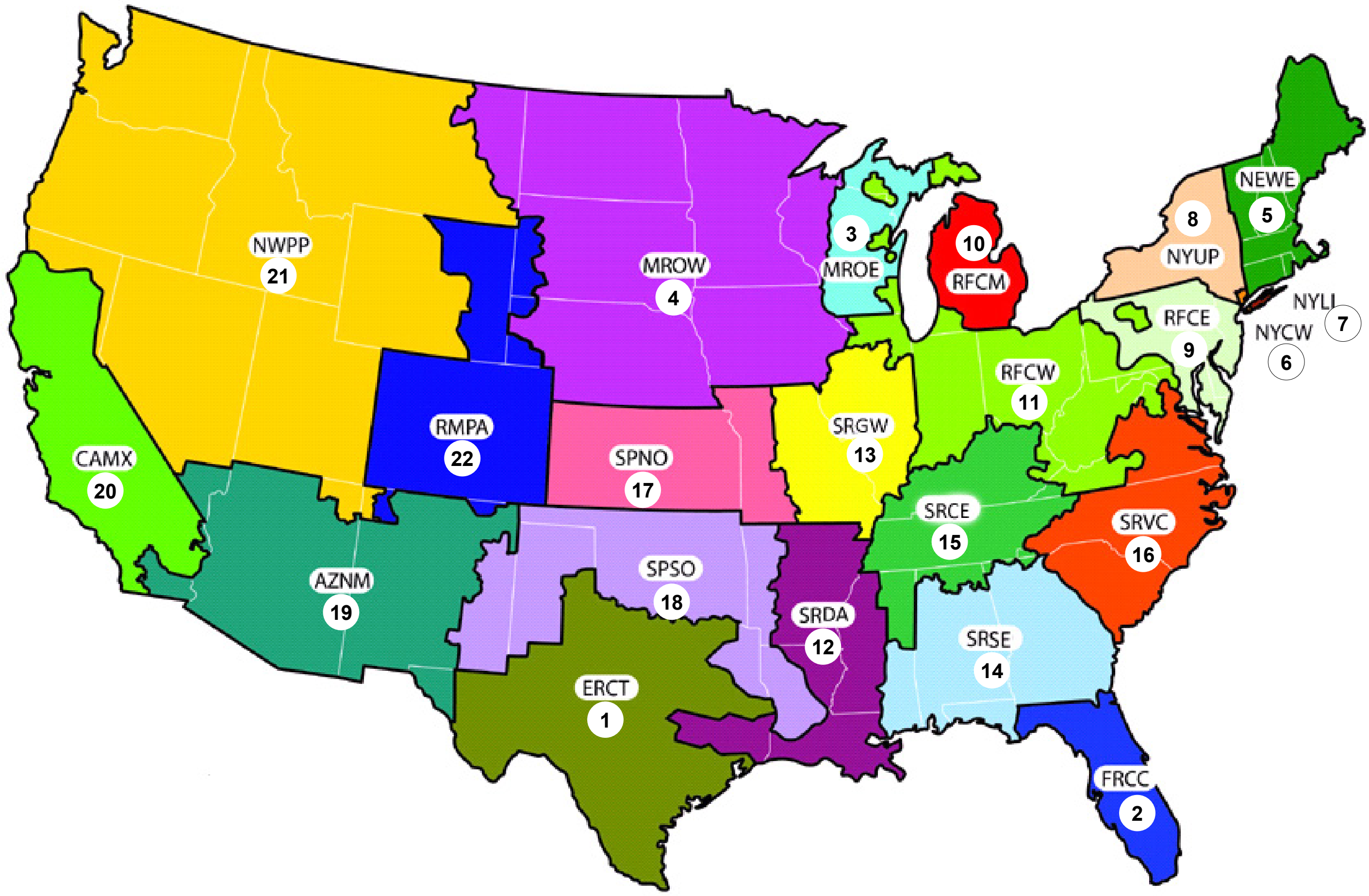
Arizona
Colorado
Idaho
Montana
Nevada
New Mexico
Utah
Wyoming

Division 9
Pacific

Alaska
California
Hawaii
Oregon
Washington

Source: U.S. Energy Information Administration, Office of Energy Analysis.

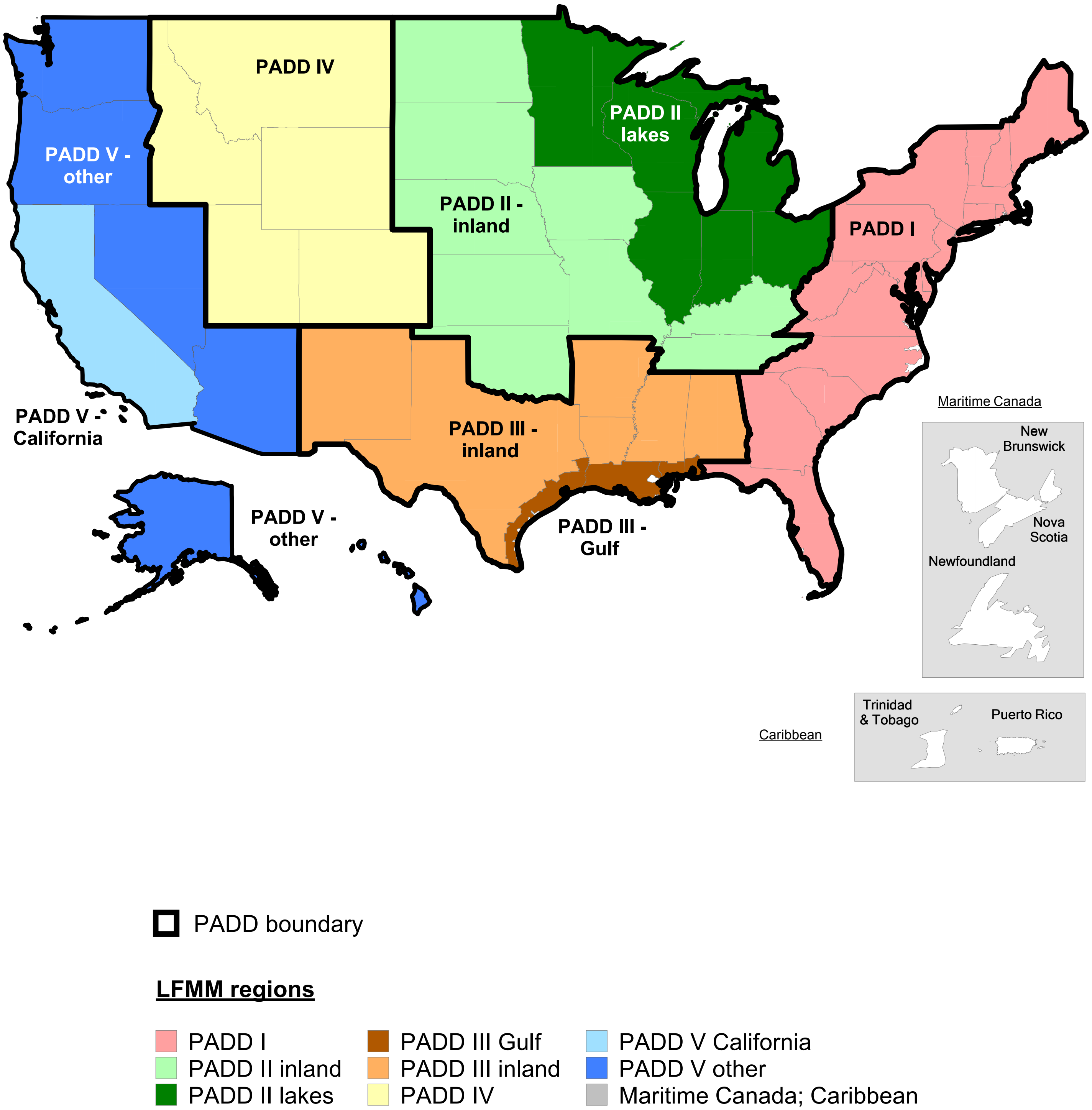
Figure F2. Electricity market module regions



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

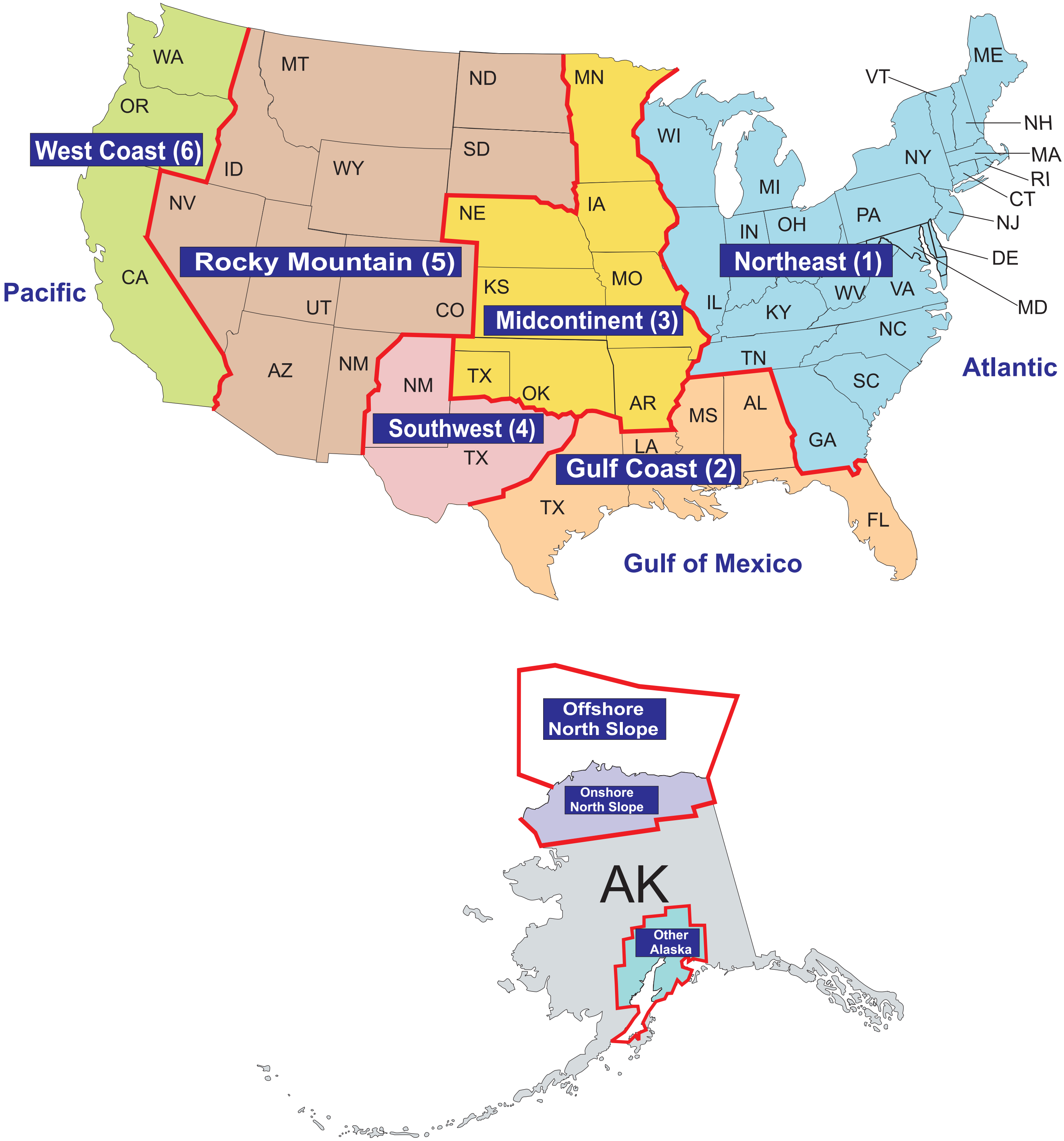
Source: U.S. Energy Information Administration, Office of Energy Analysis.

Figure F3. Liquid fuels market module regions



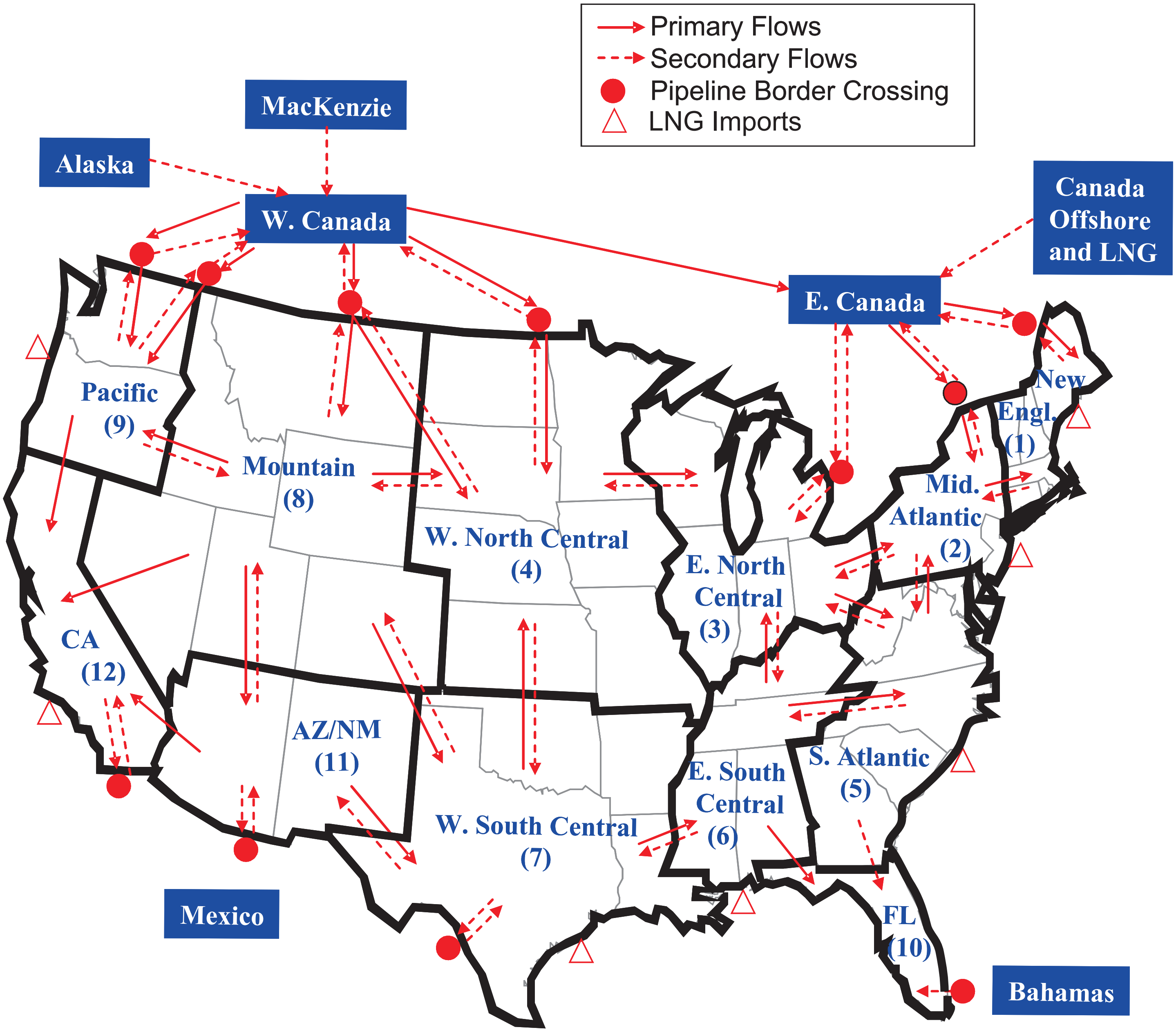
Source: U.S. Energy Information Administration, Office of Energy Analysis.

Figure F4. Oil and gas supply model regions



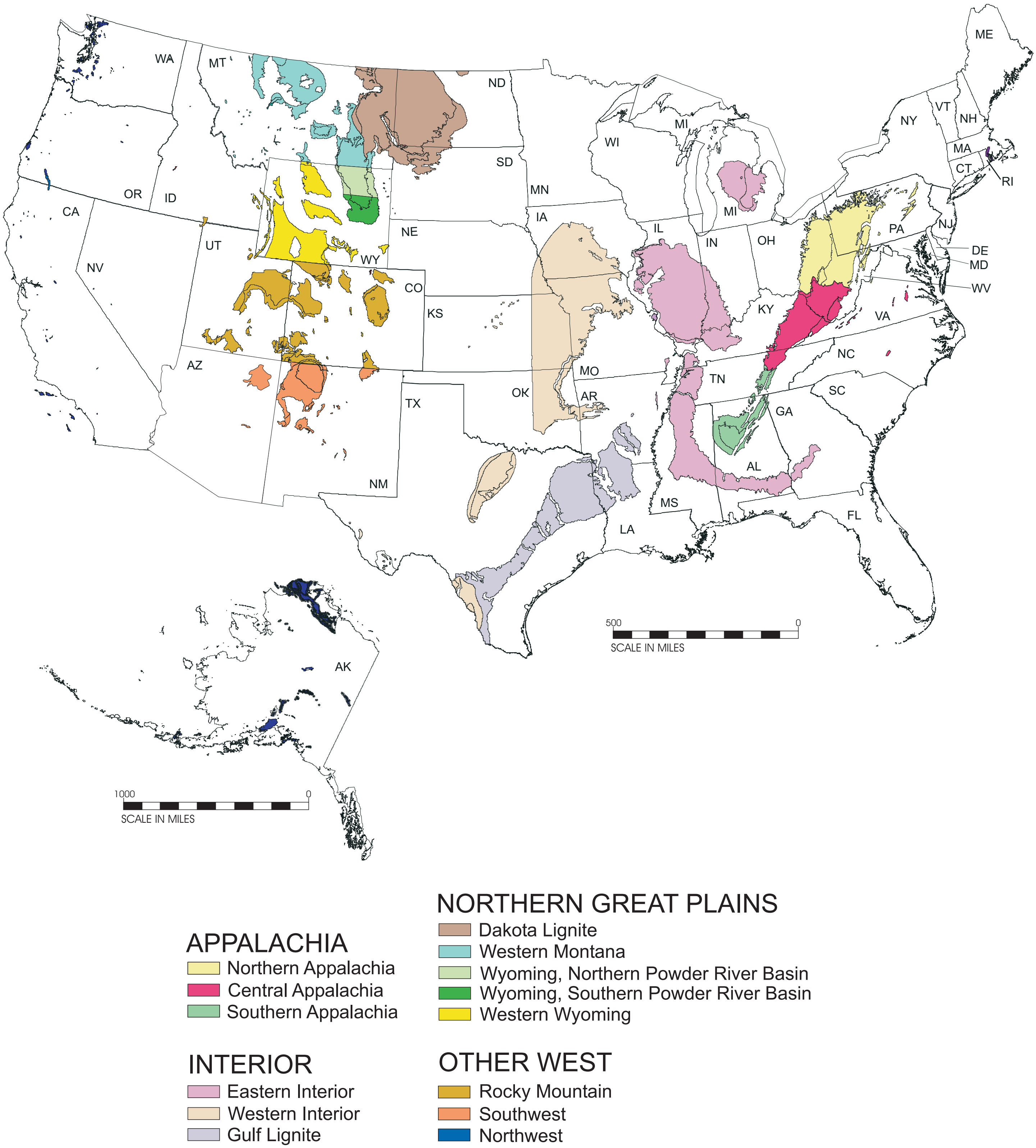
Source: U.S. Energy Information Administration, Office of Energy Analysis.

Figure F5. Natural gas transmission and distribution model regions



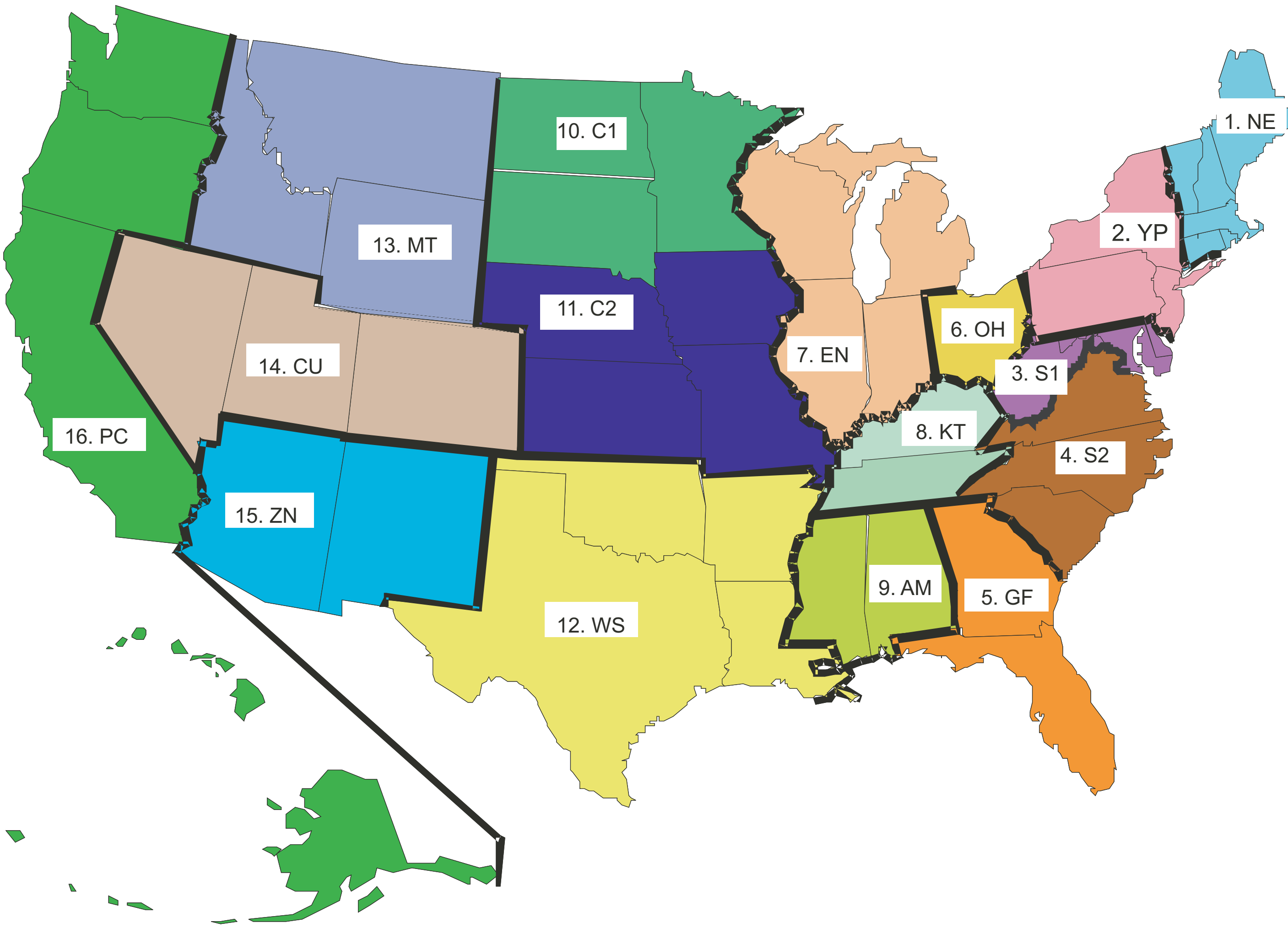
Source: U.S. Energy Information Administration, Office of Energy Analysis.

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	20.142
Consumption	million Btu per short ton	19.622
Coke plants	million Btu per short ton	26.304
Industrial	million Btu per short ton	22.999
Residential and commercial	million Btu per short ton	21.122
Electric power sector	million Btu per short ton	19.176
Imports	million Btu per short ton	25.132
Exports	million Btu per short ton	25.606
Coal coke	million Btu per short ton	24.800
Crude oil[1]		
Production	million Btu per barrel	5.850
Imports	million Btu per barrel	5.992
Petroleum products and other liquids		
Consumption[1]	million Btu per barrel	5.316
Motor gasoline[1]	million Btu per barrel	5.047
Jet fuel	million Btu per barrel	5.670
Distillate fuel oil[1]	million Btu per barrel	5.761
Diesel fuel[1]	million Btu per barrel	5.757
Residual fuel oil	million Btu per barrel	6.287
Liquefied petroleum gases and other[1,2]	million Btu per barrel	3.550
Kerosene	million Btu per barrel	5.670
Petrochemical feedstocks[1]	million Btu per barrel	5.066
Unfinished oils[1]	million Btu per barrel	6.098
Imports[1]	million Btu per barrel	5.548
Exports[1]	million Btu per barrel	5.584
Ethanol[3]	million Btu per barrel	3.560
Biodiesel	million Btu per barrel	5.359
Natural gas plant liquids[1]		
Production	million Btu per barrel	3.667
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	1,022
Electric power sector	Btu per cubic foot	1,022
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 2012.
[2]Includes ethane, natural gasoline, and refinery olefins.
[3]Includes denaturant.
Btu = British thermal unit.
Sources: U.S. Energy Information Administration (EIA), *Monthly Energy Review*, DOE/EIA-0035(2013/09) (Washington, DC, September 2013), and EIA, AEO2014 National Energy Modeling System run REF2014.D102413A.