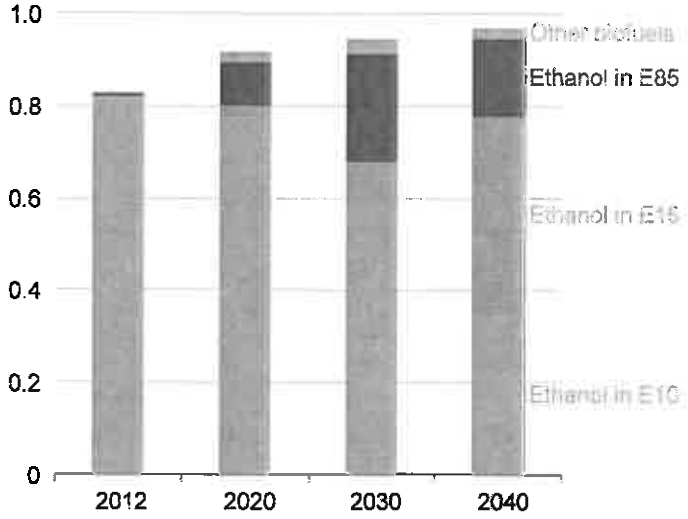
Consumption of biofuels blended into motor gasoline increases in response to RFS targets

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.

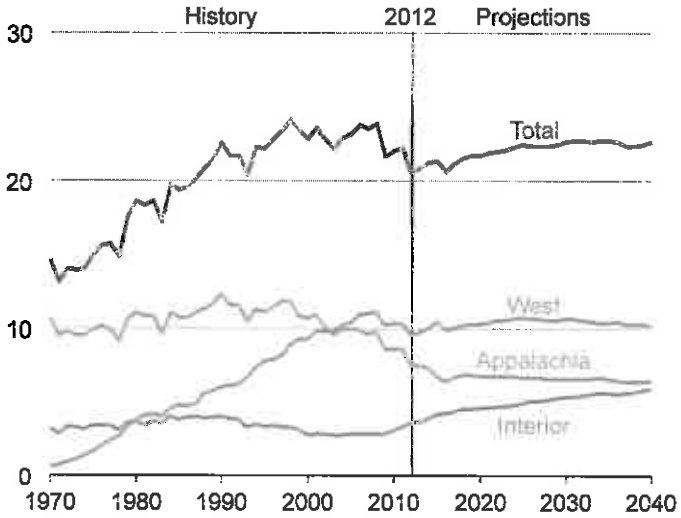
In response to RFS renewable fuel targets and market conditions, consumption of E15 increases in the Reference case, both in absolute terms and relative to E10 consumption. The growth of E15 consumption also displaces potential consumption of biobutanol blends, such as Bu16 (16% biobutanol, 84% gasoline).

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)

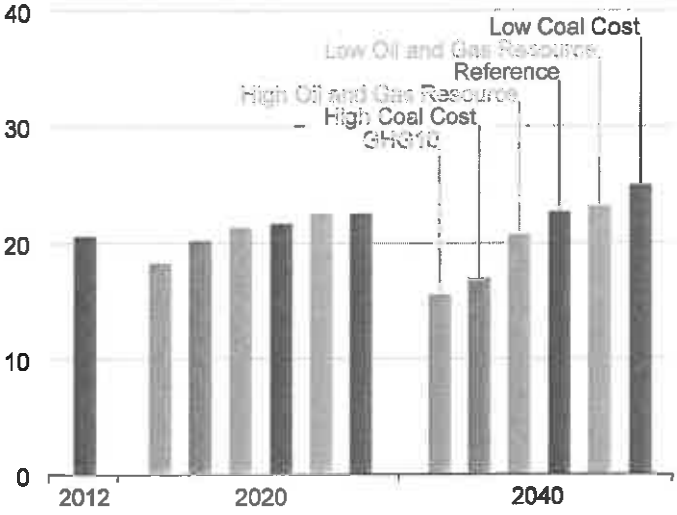


Coal production in 2012 was more than 7% below the 2011 total (Figure MT-60), mostly as a result of gas-on-coal competition. In the AEO2014 Reference case, coal production recovers briefly as natural gas prices rise before dropping to 2012 levels in 2016, as the need for electricity generators to comply 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.

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)

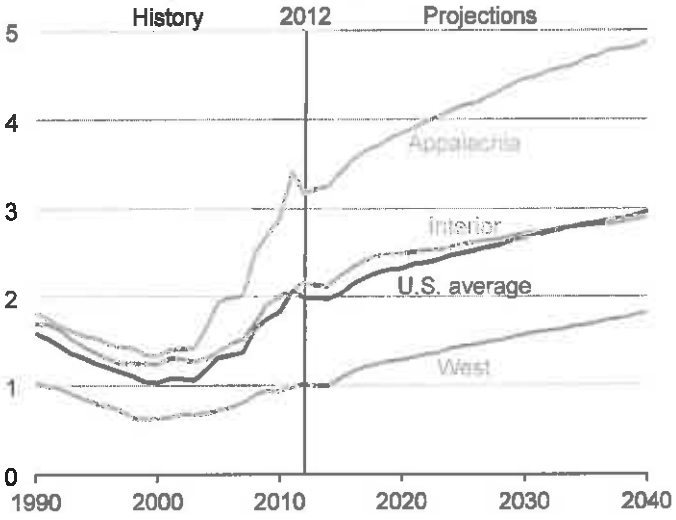


U.S. coal production varies across the AEO2014 cases, reflecting different assumptions about coal production and transportation costs, natural gas prices, and actions to limit greenhouse gas (GHG) emissions (Figure MT-61). In general, assumptions that reduce the competitiveness of coal versus natural 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 competiveness 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)



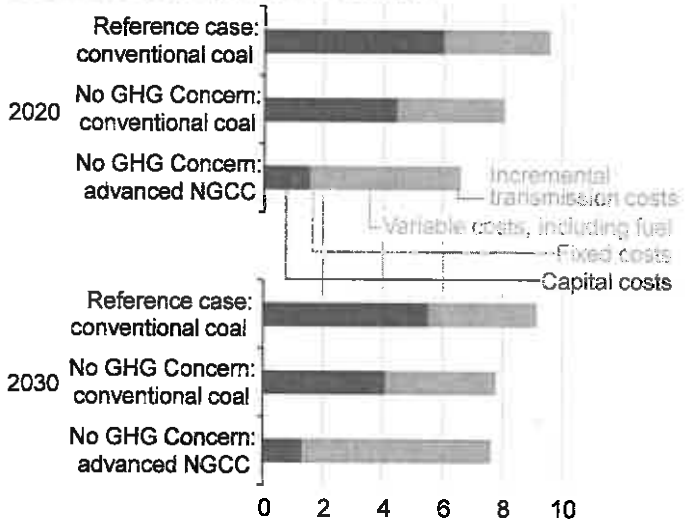
In the AEO2014 Reference case, the average real minemouth price for U.S. coal increases by 1.4%/year, from $1.98/MMBtu in 2012 to $2.96/MMBtu in 2040, continuing the upward trend that began in 2000 (Figure MT-62). A key factor underlying the higher coal prices is an expected decline in coal mining productivity 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)

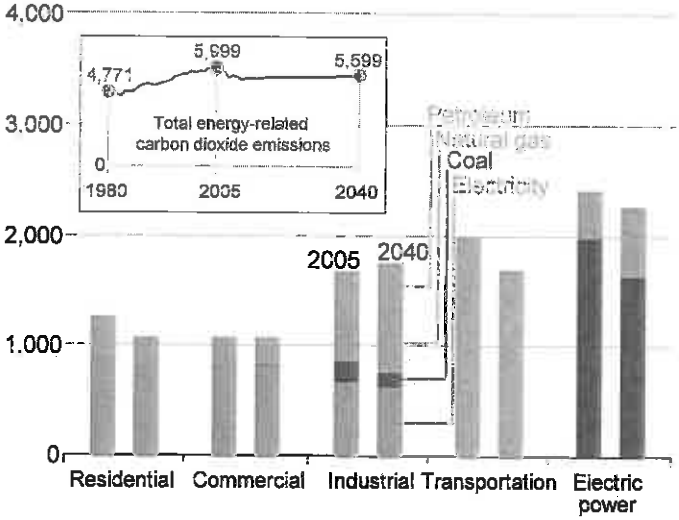


The cost of capital for investments in GHG-intensive technologies, such as new coal-fired and coal-to-liquids (CTL) plants without carbon capture and storage (CCS), is increased by 3 percentage points in the AEO2014 Reference case. This increase addresses the higher risk associated with those investments, 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)



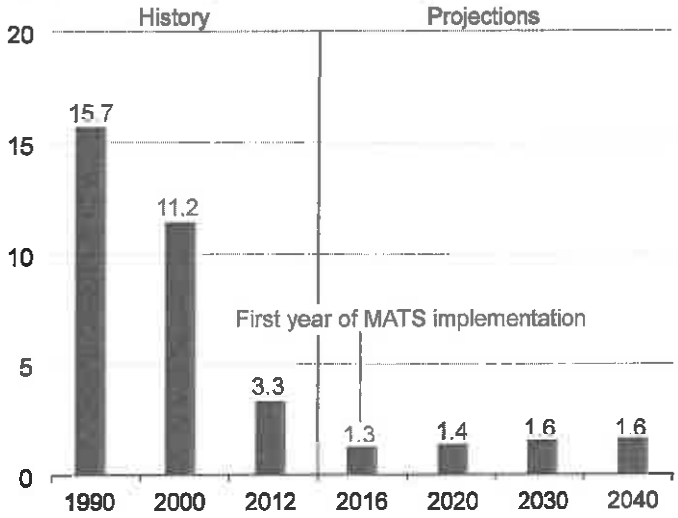
Energy-related CO_2 emissions in the AEO2014 Reference case decline by 0.2%/year on average from 2005 to 2040, as compared with an average increase of 0.9%/year from 1980 to 2005. Reasons for the decline include lower economic growth, increasing use of renewable technologies and fuels; automobile efficiency 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.

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.

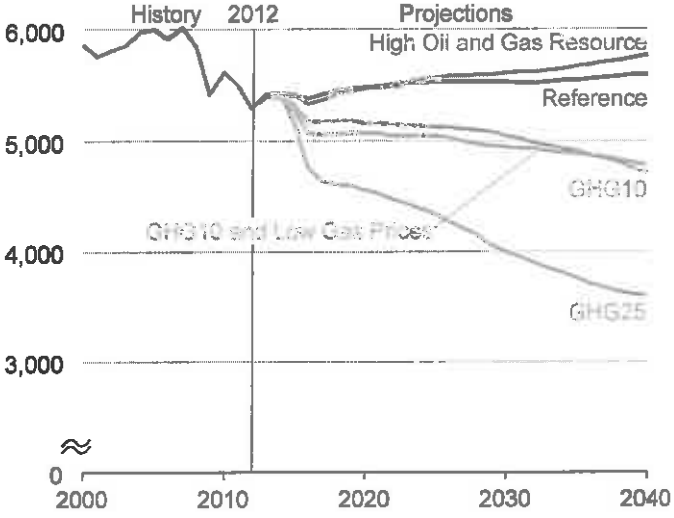
The Reference case assumes that all coal-fired power plants operating in the United States will be equipped with either flue gas desulfurization units (scrubbers) or dry sorbent injection (DSI) systems by 2016 to comply with the specific requirements of MATS. The emissions controls have the ancillary 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)



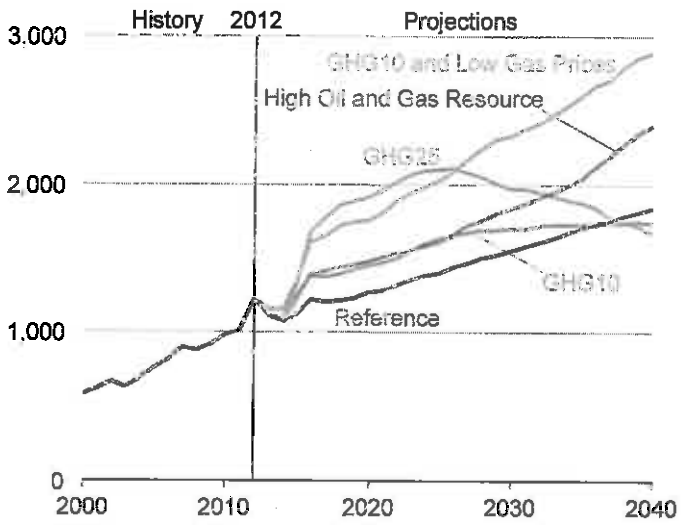
Although the AEO2014 Reference case assumes that current laws and regulations remain in effect through 2040, the potential impacts of future policies that would place an implicit or explicit value on CO_2 emissions are examined in two cases, starting at $10 (GHG10) and $25 (GHG25) per metric ton CO_2 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), http://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), http://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/todayinenergy/.
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/twiprint.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_mbbld_a.htm and http://www.eia.gov/dnav/pet/pet_pnp_inp2_dc_nus_mbbld_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.

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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.

Comparison with other projections

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)

	2012		Projections					
			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.

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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**	**4,858**	**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	7.5	--	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					
Projection	2012	(million short tons)	(quadrillion Btu)	EVA[a]	ICF[b]	IHSGI[c]	INFORUM	IEA[d]	BP[d]
				(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					
Projection	2012	(million short tons)	(quadrillion Btu)	EVA[a]	ICF[b]	IHSGI[c]	INFORUM	IEA[d]	BP[d]
				(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/tables.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/free/2013/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/free/2013/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/free/2013/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/free/2013/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/free/2013/weo2013.pdf. **BP:** BP, p.l.c., e-mail from Mark J. Finley, January 17, 2014.

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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

Appendix A

Reference case

Table A1. Total energy supply, disposition, and price summary

(quadrillion Btu per year, unless otherwise noted)

Supply, disposition, and prices	Reference case							Annual growth 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	95.55	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[8]	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[15]	6.95	6.85	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	24.52	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[5]								
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[6]	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.
[6]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[4]	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[4]	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[8]	6.08	6.04	6.85	7.45	8.04	8.73	9.54	1.8%
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[6]	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[5]	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	6.85	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							Annual growth 2012-2040 (percent)
	2011	2012	2020	2025	2030	2035	2040	
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	1.16	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							Annual growth 2012-2040 (percent)
	2011	2012	2020	2025	2030	2035	2040	
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							Annual growth 2012-2040 (percent)
	2011	2012	2020	2025	2030	2035	2040	
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	8.82	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	16.75	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[5]								
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	252.4	257.5	254.7	248.9	245.1	244.6	246.7	-0.2%
Food products	96.4	96.8	106.4	111.9	116.2	119.8	123.7	0.9%
Paper products	74.5	71.0	69.9	70.9	70.9	71.6	73.2	0.1%
Bulk chemicals	254.8	247.7	295.6	313.5	310.4	295.8	282.2	0.5%
Glass	15.5	15.4	16.1	16.3	17.1	16.7	16.1	0.2%
Cement and lime	29.0	29.1	42.2	43.6	45.0	45.7	47.3	1.8%
Iron and steel	126.9	124.8	136.5	142.4	133.7	120.9	110.4	-0.4%
Aluminum	45.3	45.6	50.3	54.2	49.7	41.2	36.3	-0.8%
Fabricated metal products	37.8	38.2	42.3	44.3	43.8	43.0	42.2	0.4%
Machinery	21.4	21.8	25.0	27.1	28.2	28.2	28.2	0.9%
Computers and electronics	46.3	46.4	50.5	57.4	61.7	64.6	65.8	1.3%
Transportation equipment	41.7	44.3	50.5	53.2	58.2	62.1	65.0	1.4%
Electrical equipment	8.3	8.2	9.1	9.9	10.5	10.9	11.1	1.1%
Wood products	15.6	15.4	20.7	20.3	19.4	18.2	17.5	0.5%
Plastics	39.7	38.7	42.4	44.3	44.6	44.0	43.6	0.4%
Balance of manufacturing	159.7	154.0	166.2	174.3	179.4	185.8	195.5	0.9%
Total manufacturing	**1,265.2**	**1,254.9**	**1,378.4**	**1,432.6**	**1,433.9**	**1,413.3**	**1,404.8**	**0.4%**
Nonmanufacturing								
Agriculture	71.0	65.5	75.7	76.7	77.3	77.4	77.7	0.6%
Construction	59.7	61.0	81.1	83.9	86.6	88.7	91.7	1.5%
Mining	100.5	101.0	113.3	111.5	107.4	103.9	100.1	0.0%
Total nonmanufacturing	**231.1**	**227.5**	**270.1**	**272.1**	**271.3**	**270.0**	**269.5**	**0.6%**
Discrepancy[5]	4.9	-2.6	39.1	47.5	56.2	66.6	74.1	--
Total industrial								**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							Annual growth 2012-2040 (percent)
	2011	2012	2020	2025	2030	2035	2040	
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[5]	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.

Appendix B

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			2030			2040		
		Low economic growth	Reference	High economic growth	Low economic growth	Reference	High economic growth	Low economic growth	Reference	High economic growth
Production										
Crude oil and lease condensate	13.87	20.31	20.38	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**	**96.87**	**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	Projections								
		2020			2030			2040		
		Low economic growth	Reference	High economic growth	Low economic growth	Reference	High economic growth	Low economic growth	Reference	High economic growth
Prices (nominal dollars per unit)										
Crude oil spot prices (dollars per barrel)										
Brent	111.65	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	2.98	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	27.89	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			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	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	48.61	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			2030			2040		
		Low economic growth	Reference	High economic growth	Low economic growth	Reference	High economic growth	Low economic growth	Reference	High economic growth
Average price to all users[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	26.87	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**	**2,036.94**	**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(2013/08) (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	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
Real gross domestic product	**13,593**	**15,918**	**16,753**	**17,594**	**18,910**	**21,139**	**22,725**	**23,158**	**26,670**	**29,164**
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.

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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	116.99	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	0.75	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	1.38	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	0.48	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**	**25.60**	**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	3.56	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	10.28	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	5,748	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	30.88	40.19	22.73	34.53	45.47
Residual fuel oil	20.07	6.73	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	258.46	268.11	272.82	280.40	301.65	306.58	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	27.84	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	28.69	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	56.85	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	32.81	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	12.61	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	875.80	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	3.36	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	3.88	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	3.88	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	6.43
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	1.88	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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Appendix D

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	2.80	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%	5.8%	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[a]	1,032	1,022	1,000	996	1,105	1,084	1,055	1,228	1,262	1,198
Coal	307	256	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[b]	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[a]	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	1,676	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[b]	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[b]	3.85	5.92	5.94	6.06	7.14	6.96	6.81	8.78	8.28	8.23
Electric power[a]	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.

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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	6.16	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	18.54
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			2030			2040		
		Low Oil and Gas Resource	Reference	High Oil and Gas Resource	Low Oil and Gas Resource	Reference	High Oil and Gas Resource	Low Oil and Gas Resource	Reference	High Oil and Gas Resource
Level of travel										
(billion vehicle miles traveled)										
Light-duty vehicles less than 8,501 pounds.	2,662	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			2030			2040		
		Low Oil and Gas Resource	Reference	High Oil and Gas Resource	Low Oil and Gas Resource	Reference	High Oil and Gas Resource	Low Oil and Gas Resource	Reference	High Oil and Gas Resource
Energy use by fuel (quadrillion Btu)										
Propane	0.05	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			2030			2040		
		Low Rail LNG	Reference	High Rail LNG	Low Rail LNG	Reference	High Rail LNG	Low Rail LNG	Reference	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]	4.58	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.

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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	1.81	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	248.89	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 $204/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 37%. 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).

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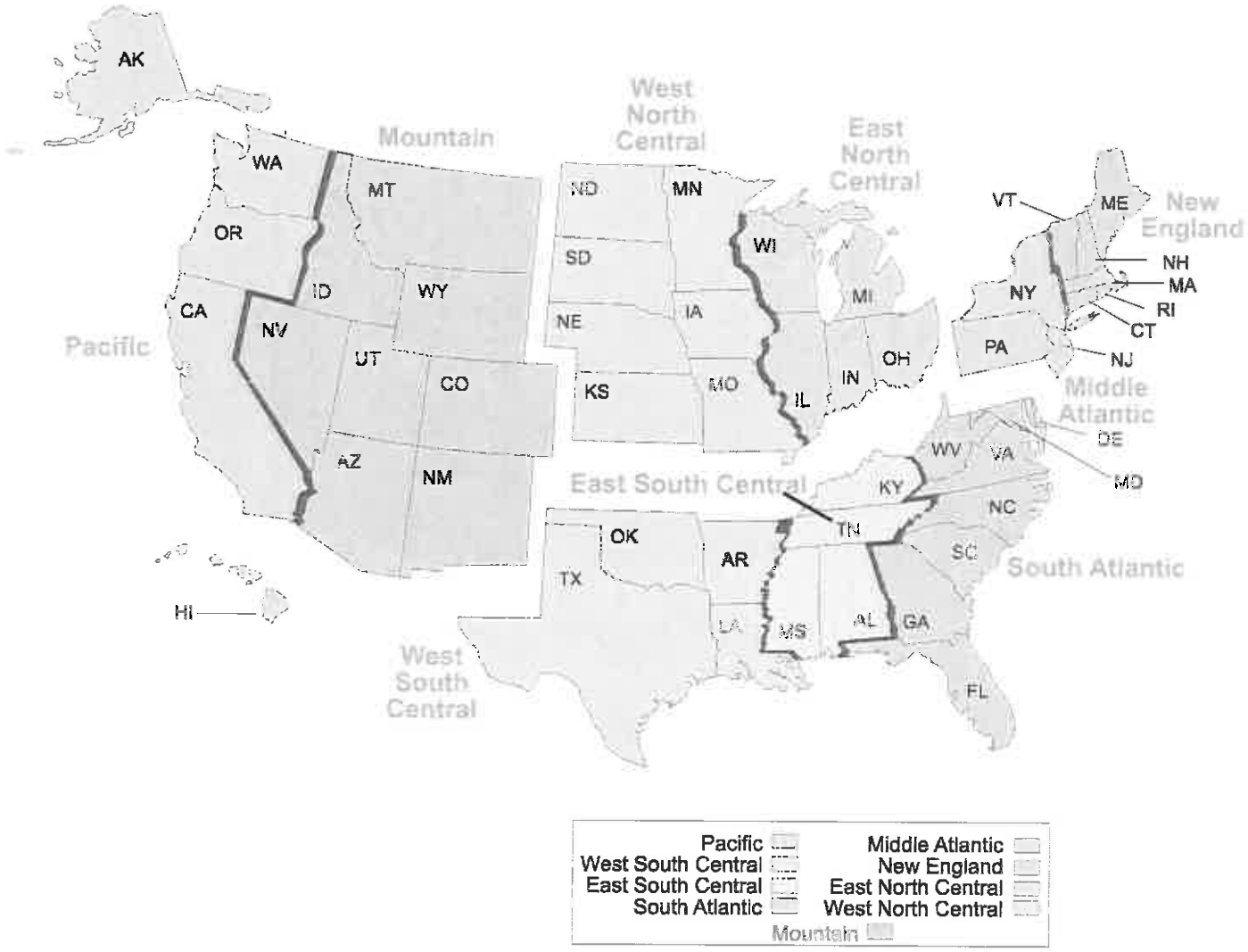
Appendix F

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

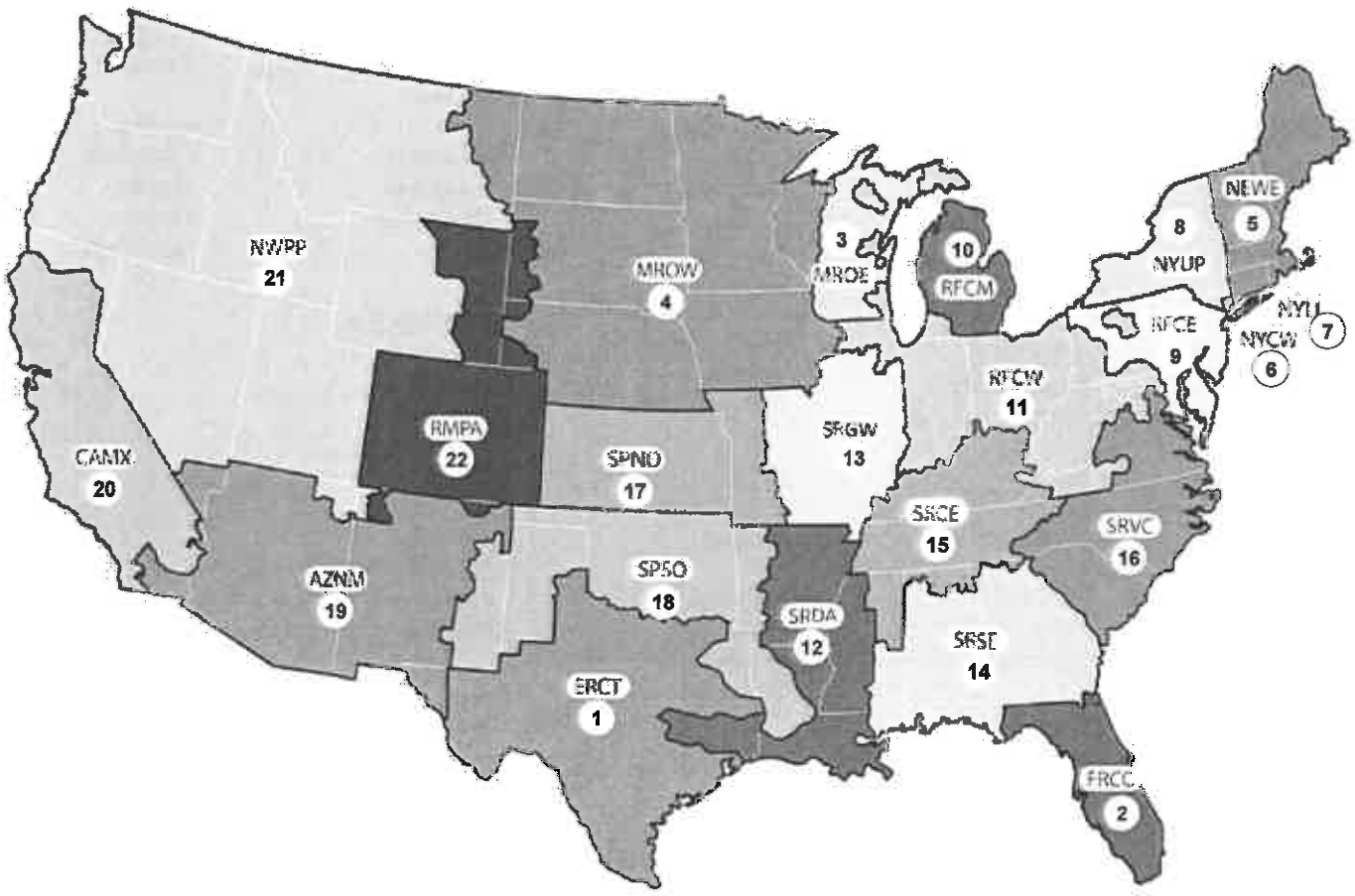
Arizona
Colorado
Idaho
Montana
Nevada
New Mexico
Utah
Wyoming

Division 9
Pacific

Alaska
California
Hawaii
Oregon
Washington

Source: U.S. Energy Information Administration, Office of Energy Analysis.

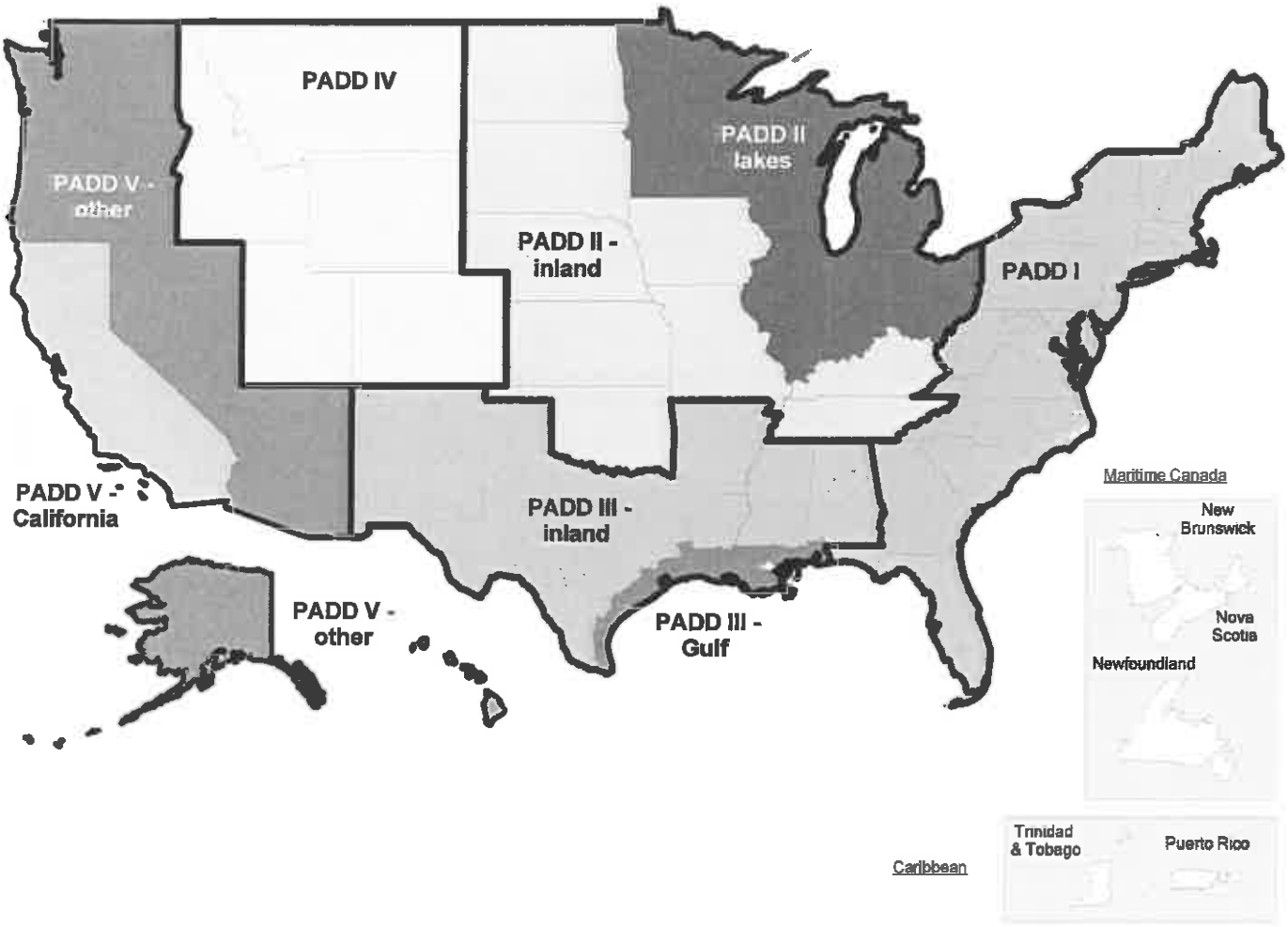
Figure F2. Electricity market module regions



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

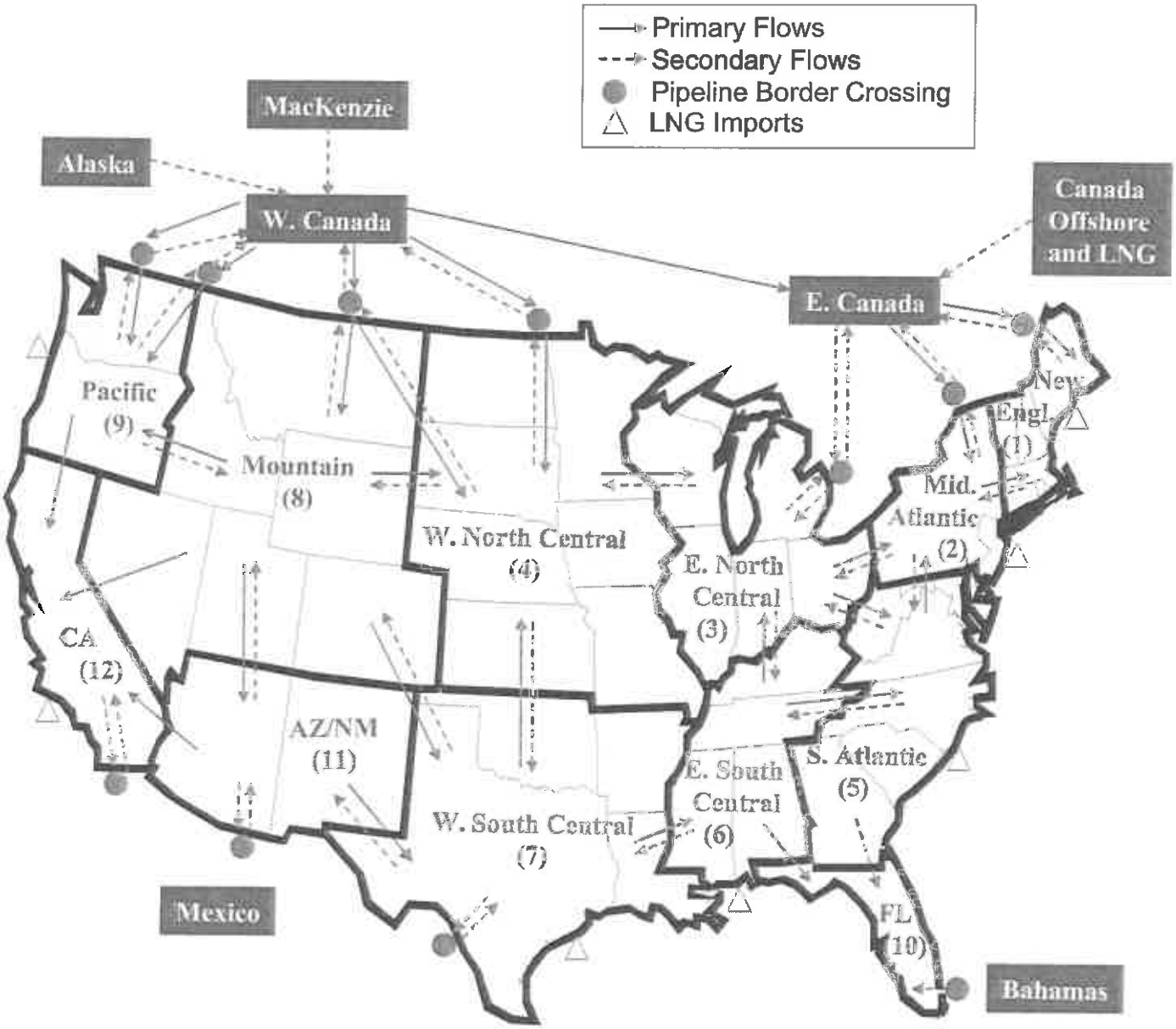


Source: U.S. Energy Information Administration, Office of Energy Analysis.

Figure F4. Oil and gas supply model regions

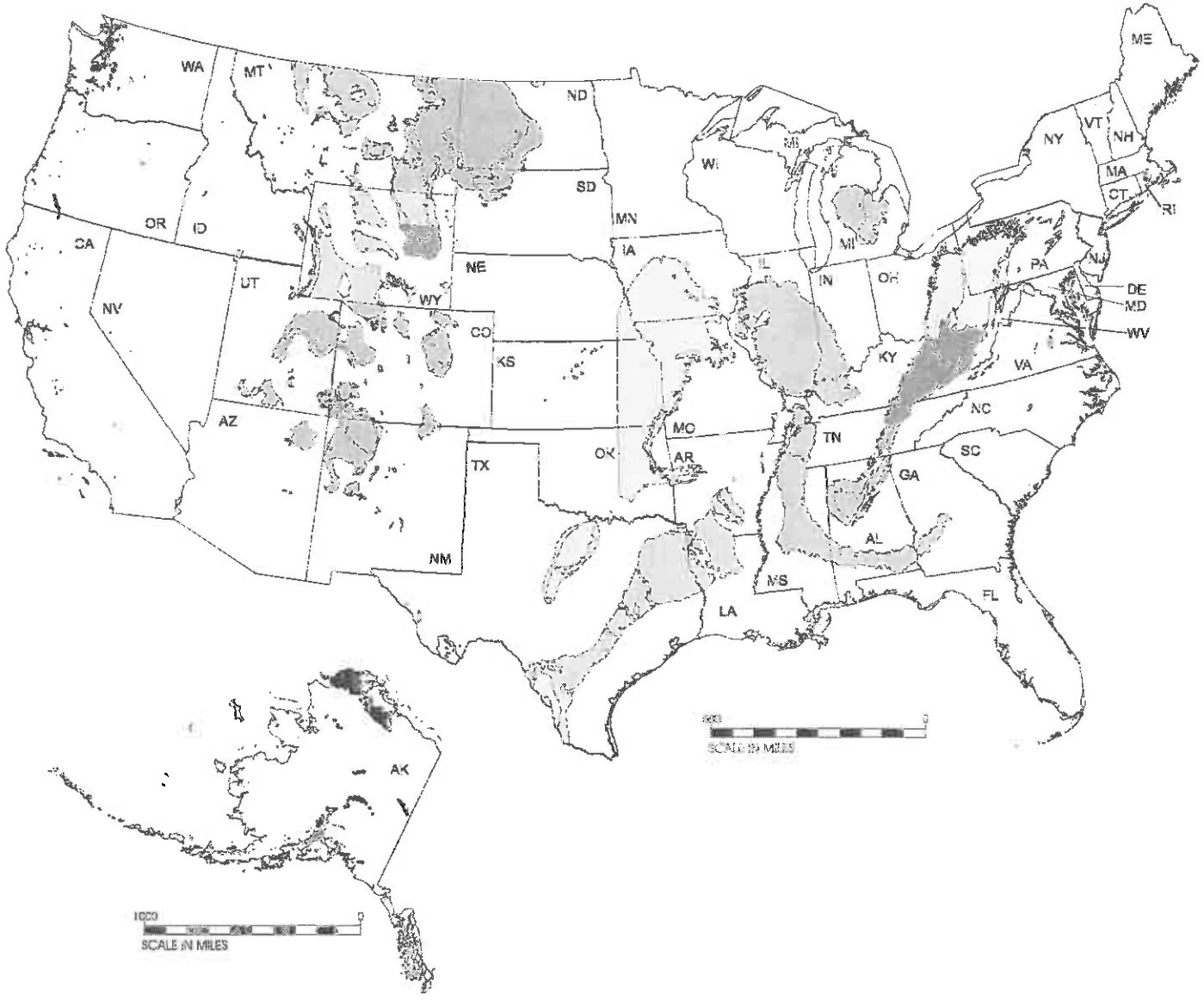
Source: U.S. Energy Information Administration, Office of Energy Analysis.

Figure F5. Natural gas transmission and distribution model regions



Source: U.S. Energy Information Administration, Office of Energy Analysis.

Figure F6. Coal supply regions



APPALACHIA
- Northern Appalachia
- Central Appalachia
- Southern Appalachia

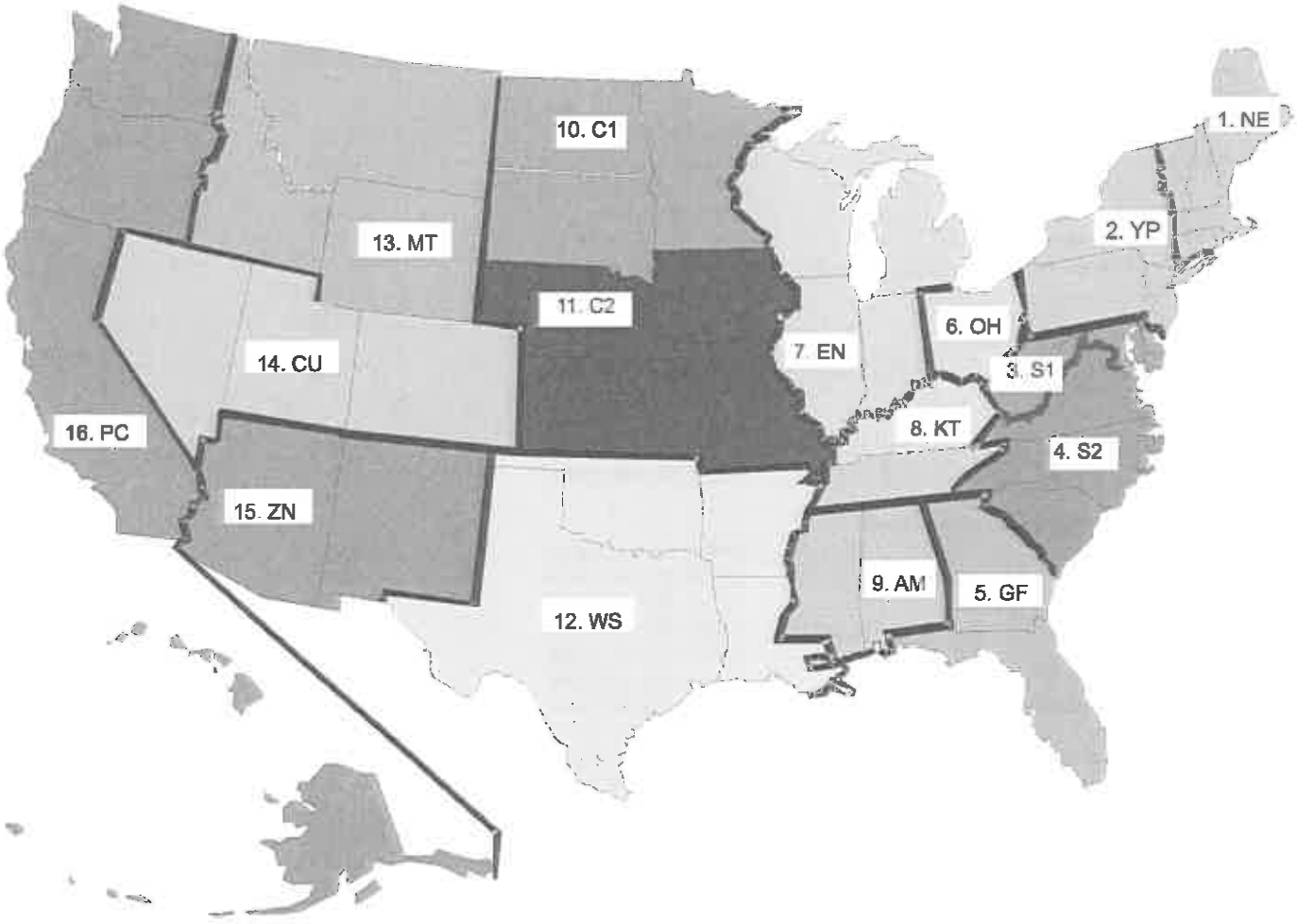
INTERIOR
- Eastern Interior
- Western Interior
- Gulf Lignite

NORTHERN GREAT PLAINS
- Dakota Lignite
- Western Montana
- Wyoming, Northern Powder River Basin
- Wyoming, Southern Powder River Basin
- Western Wyoming

OTHER WEST
- Rocky Mountain
- Southwest
- Northwest

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.

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Appendix S:

Ohio EPA Comments: Proposed Carbon Pollution Standards for New Power Plants

OhioEPA

John R. Kasich, Governor
Mary Taylor, Lt. Governor
Craig W. Butler, Director

May 9, 2014

Air and Radiation Docket and Information Center
Attention Docket ID No. EPA-HQ-OAR-2013-0495
U.S. Environmental Protection Agency
Mail Code: 2822T
1200 Pennsylvania Avenue, NW
Washington, DC 20460

Re: Comments on the Proposed Carbon Pollution Standards for New Power Plants

To whom it may concern:

The Ohio Environmental Protection Agency (Ohio EPA) is providing comment on the above-referenced proposed rule regarding the New Source Performance Standards (NSPS) for emissions of carbon dioxide (CO_2) for new fossil fuel-fired electric utility generating units (EGUs). For the first time, U.S. EPA is establishing limits of carbon dioxide emissions for new fossil fuel-fired EGUs greater than 25 megawatts and suffice to say, we have great concerns with this proposed rule. To that end, Ohio EPA submits the following comments.

A. Departure from Past NSPS Practices

The proposed rule represents a significant departure from the established U.S. EPA precedent for NSPS implementation. Specifically, the proposed NSPS sets standards based on projected emissions of future projects as opposed to developing standards based on what is currently achieved in practice. Furthermore, U.S. EPA's proposed standards offer a competitive advantage for one fuel (natural gas) at the expense of another fuel (coal). Specific comments for these issues are detailed below.

1. EPA should adopt a standard that reflects technology that is available today without carbon capture and sequestration (CCS).

   U.S. EPA's proposed rule is inconsistent with Section 111(a)(1) of the Clean Air Act. The proposed language states: "CCS technology has been adequately demonstrated, and its implementation costs are reasonable." In fact, this technology, on a commercially viable scale, has yet to be demonstrated on any operational coal-fired EGU.

   In the past, U.S. EPA has based NSPS on methods that have actually been achieved in practice. If required to develop a viable NSPS for CO_2, the U.S. EPA should follow its past precedent and examine the existing fleet of coal-fired power plants and select the most efficient units in terms of lbs CO_2/MWh, and set the NSPS for new plants

accordingly. Not only would this approach be consistent with past practice, new EGUs would have an appropriate and achievable target that will reduce CO_2 in the future.

2. U.S. EPA should follow the same methodology for coal as was used for natural gas.

Emission rates of natural gas-fired combined cycle facilities that were in operation from 2006 to 2010 were reviewed to develop the proposed natural gas standard of 1,000 lbs CO_2/MWh. U.S. EPA should use a similar method for coal plants. It is Ohio's opinion that consistent methods for determining a proposed standard be used, otherwise, it will be easily suggested that this proposed rule for EGU's is biased against coal and threatens to remove coal from future, potentially viable projects.

All illustration of how U.S. EPA is proposing an unleveled playing field when setting a standard for coal is evident from U.S. EPA's selection of partial CCS as the Best System of Emission Reduction (BSER) for coal, while approving the less stringent natural gas combined cycle (NGCC) BSER for natural gas. U.S. EPA has clearly selected a "winning fuel" (natural gas) over a "losing fuel" (coal). Not only does this approach goes beyond U.S. EPA historical precedent and regulatory authority, it does not meet congressional intent. Congress did not intend for U.S. EPA to effectively ban new coal-fired power plants. In fact, 42 U.S.C. § 7411(b)(5) (Section 111(b)(5) of the Clean Air Act) forbids U.S. EPA from restricting owners and operators to installing and operating a particular technology to meet a standard of performance.

In addition to the alternative method of creating a standard for coal versus natural gas, the emissions reductions of each fuel are not comparable. The average emission rates for natural gas-fired generation are 1,135 lbs CO_2/MWh.[1] U.S. EPA is proposing a standard performance of 1,000 lbs CO_2/MWh for natural-gas fired generation. This standard calls for a 12% reduction in average CO_2 emissions. The average emission rates for coal-fired generation are 2,249 lbs CO_2/MWh.[2] U.S. EPA is proposing a standard of performance of 1,100 lb CO_2/MWh for coal-fired power plants. This standard calls for a 51% reduction in average CO_2 emissions. Obviously, U.S. EPA asks coal-fired EGUs to dramatically reduce their CO_2 emissions unlike the modest emissions decrease requested for natural gas-fired EGUs.

B. Technical Infeasibility for Coal: Standard Based on Future Plants

U.S. EPA should not consider projects before they are permitted, operational, or even built as support for the determination that carbon capture and sequestration is a commercially available technology for the NSPS. U.S. EPA is using power plants that are not only tentative, future projects, but also projects that have received heavy funding by government entities as a basis for setting national policy in this proposed rule. U.S. EPA cannot guarantee that this level of funding will be available from the federal government for all future projects. In addition, many of the projects' costs are not representative of total costs, as the costs may, and have for many of the projects, increased as construction progresses. Many of these projects have not yet finished construction, and one has yet to receive all of the final state approvals. A NSPS using these projects departs from the longstanding, precedential U.S. EPA approach and is not

[1] http://www.epa.gov/cleanenergy/energy-and-you/affect/air-emissions.html
[2] http://www.epa.gov/cleanenergy/energy-and-you/affect/air-emissions.html

consistent with the statement that CCS technology has been adequately demonstrated and its implementation costs are reasonable.

U.S. EPA's CCS technology examples also skews affordability because every plant uses enhanced oil recovery (EOR). EOR provides a substantial revenue stream to offset the high capital costs and operating costs of CCS. However, EOR is not available in many parts of the country. U.S. EPA should not develop a standard based on the economics relevant to only a fraction of the country. A national standard such as the NSPS must be independently, economically and technically achievable throughout the country, not just in limited areas. Any other approach is inconsistent with the Clean Air Act. Also, U.S. EPA should not use future projects that may not be in operation for years and thus only have optimistic performance projections and hopeful expenditures estimates without considering the country-wide economic and technical feasibility of these projects.

The projects being used to create a standard of performance are listed below including their estimated operational date and costs:

1. Southern Company's Kemper County Energy Facility. This project has received $270 million from the Department of Energy (DOE) and $133 million in investment tax credits from the Internal Revenue Service.[3] Unless the DOE's Clean Coal Power Initiative, the program that donated $270 million to Southern Company, intends to help fund all future projects, the economic viability of this technology will be vastly different for future projects. In addition, this project will not be operational until for several months in the future.

2. SaskPower's Boundary Dam CCS Project. This Canadian project costs $1.355 billion and is also receiving a heavy subsidy of $240 million from the federal government.[4] Performance testing is currently scheduled, but the facility will not be fully functional until sometime in the future. SaskPower claims to be leading the way in developing CCS technology.[5] Standards should not be based on developing technologies that are not commercially tested.

3. Summit Power's Texas Clean Energy Project (TCEP). This project's estimated total cost is $1.727 billion. This project is heavily subsidized, with the DOE share being $450 million (26%).[6] The DOE awarded $350 million in December 2009 for an eight-year joint project with University of Texas Bureau of Economic Geology. TCEP received an additional $100 million from the American Recovery and Reinvestment Act (ARRA) in August 2010. TCEP received the $450 million award in 2010 from the DOE's Clean Coal Power Initiative (CCPI). The project has not commenced construction and is years past the original projected 2011 date. The project also lost its major electricity customer due to the high electric costs. Consequently, the entire project is in jeopardy. This example shows that even with government subsidies and enhanced oil recovery, this standard is not feasible.

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[3] http://sequestration.mit.edu/tools/projects/kemper.html.
[4] http://sequestration.mit.edu/tools/projects/boundary_dam.html.
[5] http://www.saskpower.com/our-power-future/work-currently-underway/.
[6] http://sequestration.mit.edu/tools/projects/tcep.html.

4. Hydrogen Energy California Project (HECA). This project will cost $4.028 billion.[7] This project is heavily subsidized. It was awarded a $408 million grant by the DOE under Clean Coal Power Initiative Round 3. The project has not yet broken ground, started construction, received final state approval or even negotiated an agreement for the purchase of power. Without the necessary approvals this plant may not even be built. The project, if built, may be operational in 2017 with a more realistic date in 2018 or 2019. The basis for the NSPS should be more concrete than a speculative plant that may be constructed sometime in the future.

C. Infeasibility of Carbon Capture and Sequestration (CCS) Technology

Ohio EPA believes that carbon capture and sequestration, which holds possible promise sometime in the future, is not a commercially available control technology. The study on which U.S. EPA relies focuses on a range of CO_2 capture levels for *new* supercritical pulverized coal (SCPC) and integrated gasification combined cycle (IGCC) power plants.[8] This study shows high costs for carbon capture and sequestration technology even on the smallest scale. While components of carbon capture and sequestration are currently in use, all the technological components do not currently function together on a commercial scale.[9] In order to be considered commercial, carbon capture and sequestration technology needs to be cost effective without government subsidies and not reliant upon enhanced oil recovery to subsidize the operation of carbon capture and sequestration. Further, carbon capture and sequestration may not be a viable technology due to water constraints or the lack of sufficient geological structure to accept carbon capture and sequestration underground injection technology.

D. Feasibility of Existing Reduction Technology as NSPS

The Ohio EPA believes that the standard should be based on the performance of existing highly efficient generation technology that does not include carbon capture and sequestration, such as supercritical pulverized coal (SCPC), circulating fluidized bed (CFB) boiler, or a modern, efficient integrated gasification combined cycle (IGCC) unit. U.S. EPA has acknowledged that these options are technically feasible but has stated that the reductions of emissions are not adequate to reach its arbitrary goal. The NSPS is a technology-based standard, not an air quality standard driven program. U.S. EPA should not use the NSPS in an attempt to reach some predetermined reduction standard or issue standards that support only certain industries or technologies. Ohio EPA believes that reduction levels using current technology are not only adequate, but necessary in order to ensure that U.S. EPA develops a standard that is consistent with the approach used to develop the natural gas NSPS.

U.S. EPA estimates that a new SCPC unit firing coal would emit 1,700 lbs CO_2/MWh and a new IGCC unit would emit 1,450 lbs CO_2/MWh; compared to the average emissions from coal-fired power plants discussed above. These are 25% and 36% emissions reductions, respectively. CFB boilers have also been shown to reduce emissions by at least 20%.[10] These reductions are more than twice the reductions proposed for natural gas plants. These

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[7] http://sequestration.mit.edu/tools/projects/heca.html.
[8] http://www.netl.doe.gov/energy-analyses/pubs/Gerdes-08022011.pdf.
[9] Howard J. Herzog, *Scaling Up Carbon Dioxide Capture and Storage: From Megatons to Gigatons*, Energy. Econ. 2011 33, 597-604.
[10] H. Arro, A. Prikk, T. Pihu, *Calculation of CO2 Emissions From CFB Boilers of Oil Shale Power Plants*, Oil Shale, Vol. 23, No. 4, 356-365 (2006).

technologies are not only proven with existing performance, but also provide real emissions reductions. IGCC plants in operation include the 262 MW Wabash River Plant, the 250 MW Tampa Electric Coke Power Station, and the 618 MW Duke Energy Edwardsport plant. New supercritical plants that have been come on line include the We Energies Elm Road Generating Station, Xcel Energy Comanche Generating Station Unit 3, and Luminant's Oak Grove Plant. Fluidized bed power plants are being constructed and operated in a number of countries throughout the world.

Ohio EPA believes that a modern, efficient IGCC unit should be the BSER for coal. IGCC units are currently in operation and can provide reliable performance data. In addition, total costs for IGCC units are easier to analyze, as existing units have calculated total costs, while the CCS projects only have optimistic cost estimates. Emissions reductions with an IGCC unit are still aggressive enough to meet the U.S. EPA's overall goal of reducing carbon emissions, while still allowing for new plants to be technically and economically feasible. In addition, using IGCC technology as a base for creating a NSPS will follow the agency's prior precedent of creating standards based on the performance of existing technology.

E. Other Considerations

1. Cost of Natural Gas

   Presently, natural gas prices are near historic lows, and much of the NSPS is based on the presumed continuation of these low costs into the future. Historically, the fuel commodities market, including natural gas, has been extremely volatile and sensitive to not only domestic influences but also to international demand and other external factors that cannot be easily forecast or controlled. The cost of the natural gas is extremely sensitive to short-term phenomena. For example, in the near future, many currently economically viable coal-fired units will be retired as a direct result of the CSAPR and MATS rules. Ohio alone has twenty-seven emitting units that are scheduled for retirement on or before 2015. At least some portion of the generating capacity of these units will need to be replaced by NGCC units, and demand for natural gas will increase rapidly in a very short time period as these new units go online. Likely, the costs of natural gas will increase with increased demand. Thus, Ohio EPA believes that the presently low cost of natural gas is being driven by short-term factors that will not be sustained over the long term and that significant and far reaching rules, such as the proposed NSPS, should not be based on predicted future costs of any commodity, especially those of fuels which have historically volatile markets.

2. Eight Year Review Option

   U.S. EPA is mandated to review NSPS every eight years under 42 U.S.C. § 7411(b)(1)(b) (Section 111(b)(1)(B) of the Clean Air Act). If U.S. EPA uses the technology for existing coal-fired power plants to set an NSPS in this proposed rule, U.S. EPA would have the ability to review and update the standard in eight years, if appropriate, which would also include a review of actual operational data from the plants with carbon capture and sequestration. This logical, step-wise approach, will allow the technology to advance, rather than practically eliminating the use of coal in new plants by adopting a standard based on speculative cost projections.

3. Supplemental Information

In further support of the proposed NSPS, U.S. EPA issued a supplemental document to provide additional technical support for the NSPS. The supplemental information identified additional examples of the application of carbon dioxide capture at non-EGU sources. Unfortunately, these examples do not represent the source category for which U.S. EPA has proposed the standard, and fail to have any practical relevance to coal-fired EGUs.

4. U.S. EPA's Proposal Adds Huge Energy Inefficiencies to Power Production

For decades, U.S. EPA has been promoting the benefits of energy efficiency. U.S. EPA has established multiple programs to require and promote energy efficiency such as Energy Star. The federal government provides tax credits for certain energy efficiency products. With that background, it is inconsistent and wasteful for U.S. EPA to mandate a specific technology that consumes an enormous power load in order to operate. Carbon capture and sequestration is estimated to consume approximately 30% of the energy output of the plant.[11] This high parasitic load means that for every one ton of coal burned in a conventional plant about 1.30 tons of coal must be burned in a carbon capture and sequestration plant. This tremendous energy penalty means that 30% more coal must be mined, transported, and burned to reach the same electrical output design as a conventional plant. If U.S. EPA examines the total impact of carbon capture and sequestration, the benefits of this technology in its current form are tenuous. The additional burning of coal needed to support CCS will also increase the amount of traditional pollutants coming from these plants along with greater emissions of hazardous air pollutants. U.S. EPA should also consider the impact of the additional excess emissions that will result from the deployment of CCS.

F. Fee Issues

1. Departure from Title V fee applicability for CO_2 as a regulated pollutant

The proposed activity-based funding approach to support a permitting authority's greenhouse gas (GHG) regulatory activities departs from the current precedent established in 40 C.F.R. § 70.9, presumptive funding of Title V activities. The fees implemented for CO_2 for sources subject to 40 CFR Part 70 should be based on the same criteria and approach used by U.S. EPA to establish the original $25/ton presumptive minimum fee for other existing Title V pollutants. The presumptive minimum fee approach is consistent and provides a baseline nationwide for funding Title V program implementation activities.

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[11] Carbon Management Technology Conference, February 2012, Paper No. CMTC-151635-PP, U.S. DOE National Energy Technology Laboratory's Post Combustion Carbon Capture R&D Program, Lynn Drake H, Jared Ciferno, Ron Munson, Jim Murphy, U.S. DOE National Energy Technology Laboratory

U.S. EPA established a nationwide $25/ton presumptive minimum fee for each "Regulated Pollutant" pursuant to authority established in Title V of the 1990 Clean Air Act Amendments. "The total amount of fees collected by the permitting authority shall conform to the following requirements: The Administrator shall not approve a program as meeting the requirements of this paragraph unless the State demonstrates that, except as otherwise provided in subparagraphs [2] (ii) through (v) of this subparagraph, the program will result in the collection, in the aggregate, from all sources subject to subparagraph (A), of an amount not less than $25 per ton of each regulated pollutant, **or such other amount as the Administrator may determine adequately reflects the reasonable costs of the permit program.**" 42 U.S.C. 7661a(b)(3)(i) (emphasis added).

Ohio EPA submits that the proposed approach for adding activity-based fees departs from the Clean Air Act requirement that the fee be based on a $/ton emitted from the subject sources. Introducing a permitting agency activity-based fee for one "carved-out" regulated pollutant, not only introduces lack of uniformity in the fee burden across approved presumptive minimum fee programs, it introduces costly and complex administrative burdens in implementing such an approach. In short, the fee structure for CO_2 should be the same as the fee structure for the other pollutants that fund Title V program implementation activities. The $/ton of CO_2 should be adjusted to establish proportional equivalency to the other pollutants due to the significantly larger CO_2 emissions levels.

2. Advantages of implementing a prorated $/ton fee for CO_2 based on reported emissions

Ohio EPA believes that a significantly reduced, prorated, federal presumptive minimum fee would be consistent with the U.S. EPA's authority to establish a fee that "....adequately reflects the reasonable costs of the permit program." A prorated fee per ton should be developed for CO_2 using the same mechanism as the current $25/ton presumptive minimum fee per pollutant and take into consideration the cap in place, which limits billing greater than 4,000 tons of actual reported emissions. This similar $/ton approach would also lend itself to more cost effective and efficient implementation by state and tribal Title V programs.

Prorating a CO_2 presumptive minimum fee could easily be implemented within the existing $/ton reporting and invoicing architecture. Introducing a different architecture to accommodate one pollutant as presented in this proposed rulemaking would be costly and complicated because the basis is completely foreign to the existing fee structure. In Ohio that would include significant modifications to software and supporting databases as well as related training of the regulated community and internal staff. Alternately, tailoring a CO_2 "fee per ton emitted" would be more consistent with tailoring applicability of GHGs to the Title V program and would result in minimal disruption or need for adjustment to existing state and tribal fee processing programs. Finally, adding an additional billable pollutant to Ohio's enabling legislation will be challenging. Introducing both a new pollutant and an additional fee structure will be much more difficult for approval.

In summary, adding a prorated, tailored presumptive minimum fee for CO_2 under the existing $25/ton consumer price index adjusted fee structure minimizes complexity,

ensures nationwide uniform application and supports timely implementation of funding activities associated with implementing greenhouse gas regulations for Title V facilities.

G. Summary

U.S. EPA's proposed NSPS for CO_2 for coal and natural gas power plants suffers from serious technical defects. The proposed rule, if adopted, will eliminate the potential for new coal-fired power plants due to the high overall cost of carbon capture and sequestration. This NSPS relies on tentative, future projects to set a standard instead of using actual data from existing plants to ensure the promulgated standard is achievable. The proposal also treats natural gas and coal inequitably, requiring a degree of control on coal plants that has not yet been achieved in practice. In contrast, the natural gas plants are able to meet the proposed standard for CO_2 by building a well-designed plant with technologies presently achievable unlike carbon capture and sequestration. Finally, U.S. EPA should not utilize the NSPS in a manner to reach a predetermined reduction of CO_2, but instead recognize existing operating technology to set the NSPS standard for coal-fired EGUs.

In order to correct the significant shortcomings of the rule, Ohio EPA believes it is necessary to re-propose a new rule that provides a level playing regulatory field for multiple energy sources to be designed, built, and operated in the U.S. and Ohio to meet our current and expected future energy demands in a cost effective and environmentally responsible manner.

Thank you for the opportunity to comment.

Sincerely,

Craig W. Butler
Director