AEO2013 Early Release Overview

Executive summary

Projections in the *Annual Energy Outlook 2013 (AEO2013)* Reference case focus on the factors that shape U.S. energy markets through 2040, under the assumption that current laws and regulations remain generally unchanged throughout the projection period. This early release focuses on the *AEO2013* Reference case, which provides the basis for examination and discussion of energy market trends and serves as a starting point for analysis of potential changes in U.S. energy policies, rules, or regulations or potential technology breakthroughs. Readers are encouraged to review the full range of cases that will be presented when the complete *AEO2013* is released in early 2013, exploring key uncertainties in the Reference case. Major highlights in the *AEO2013* Reference case include:

Crude oil production, particularly from tight oil plays, rises sharply over the next decade

The advent and continuing improvement of advanced crude oil production technologies continue to lift projected domestic supply. Domestic production of crude oil increases sharply in *AEO2013*, with annual growth averaging 234 thousand barrels per day (bpd) through 2019, when production reaches 7.5 million bpd (Figure 1). The growth results largely from a significant increase in onshore crude oil production, particularly from shale and other tight formations. After about 2020, production begins declining gradually to 6.1 million bpd in 2040 as producers develop sweet spots first and then move to less productive or less profitable drilling areas.

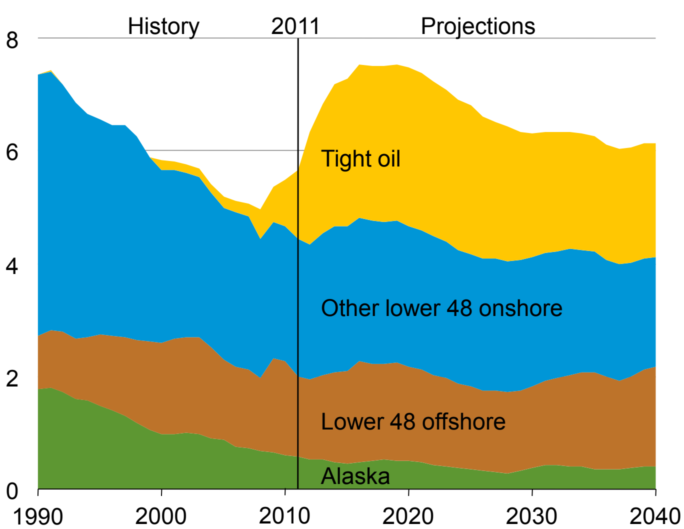
Natural gas production is higher throughout the AEO2013 Reference case projection than it was in AEO2012, with natural gas increasingly serving the industrial and electric power sectors, as well as an expanding export market

Relatively low natural gas prices, facilitated by growing shale gas production, spur increased use in the industrial and electric power sectors, particularly over the next 15 years. Natural gas use (excluding lease and plant fuel) in the industrial sector increases by 16 percent, from 6.8 trillion cubic feet per year in 2011 to 7.8 trillion cubic feet per year in 2025. Although natural gas also continues to capture a growing share of total electricity generation, natural gas consumption by power plants does not increase as sharply as generation because new plants are very efficient. After accounting for 16 percent of total generation in 2000, the natural gas share of generation rose to 24 percent in 2010 and is expected to continue increasing, to 27 percent in 2020 and 30 percent in 2040. In the *AEO2013* Reference case, natural gas also reaches other new markets, such as exports, as a fuel for heavy-duty freight transportation (trucking), and as a feedstock for producing diesel and other fuels.

Motor gasoline consumption is lower in AEO2013 relative to the level in AEO2012, reflecting the introduction of more stringent corporate average fuel economy standards; growth in diesel fuel consumption is moderated by increased use of natural gas in heavy-duty vehicles

AEO2013 incorporates the greenhouse gas (GHG) and corporate average fuel economy (CAFE) standards for light-duty vehicles (LDVs)[1] through the 2025 model year, which increases the new vehicle fuel economy from 32.6 miles per gallon (mpg) in 2011 to 47.3 mpg in 2025. The increase in vehicle efficiency reduces gasoline use in the transportation sector by 0.5 million bpd in 2025 and by 1.0 million bpd in 2035 in *AEO2013* compared to the *Annual Energy Outlook 2012 (AEO2012)* Reference case (Figure 2). Furthermore, the improved economics of liquefied natural gas (LNG) for heavy-duty vehicles results in an increase in natural gas use in heavy-duty vehicles that offsets a portion of diesel fuel consumption. The use of petroleum-based diesel fuel is also reduced by the increased use of diesel produced using gas-to-liquids (GTL) technology. Natural gas use in vehicles reaches 1.7 trillion cubic feet (including GTL) by 2040, displacing 0.7 million bpd of other motor fuels.[2]

Figure 1. U.S. domestic crude oil production by source, 1990-2040 (million barrels per day)



The United States exports more natural gas than projected in the AEO2012 Reference case

U.S. dry natural gas production increases throughout the projection period (Figure 3), outpacing domestic consumption by 2020 and spurring net exports of natural gas. Higher volumes of shale gas production in *AEO2013* are central to higher total production volumes and an earlier transition to net exports than was projected in the *AEO2012* Reference case. U.S. exports of LNG from domestic sources rise to approximately 1.6 trillion cubic feet in 2027, almost double the 0.8 trillion cubic feet projected in *AEO2012*.

[1]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), website www.gpo.gov/fdsys/pkg/FR-2012-10-15/pdf/2012-21972.pdf.

[2]Liquid motor fuels include diesel and liquid fuels from GTL processes. Liquid fuel volumes from GTL for motor vehicle use are estimated based on the ratio of onroad diesel and gasoline to total diesel and gasoline.

Industrial production expands in response to the initial competitive advantage of low natural gas prices

Industrial production grows more rapidly in *AEO2013* due to the benefit of strong growth in shale gas production and an extended period of relatively low natural gas prices, which lower the costs of both raw materials and energy, particularly through 2025. Specific industries benefit from the greater availability of natural gas at relatively low prices. For example, industrial production grows by 1.7 percent per year from 2011 to 2025 in the bulk chemicals industries—which also benefit from increased production of natural gas liquids—and by 2.8 percent per year in the primary metals industries, as compared with 1.4 percent and 1.1 percent per year, respectively, in the *AEO2012* Reference case. In the long term, growing competition from abroad in these industries limits output growth, as other nations develop and install newer, more energy-efficient facilities. The higher level of production also leads to greater industrial natural gas demand (excluding lease and plant fuel), which grows to more than 8.3 quadrillion Btu in 2035 in *AEO2013*, compared to 7.2 quadrillion Btu in 2035 in *AEO2012*. Most of the increase in industrial energy demand is the result of higher output in the manufacturing sector.

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

The share of generation from renewables grows from 13 percent in 2011 to 16 percent in 2040. Electricity generation from solar and, to a lesser extent, wind energy sources grows as recent cost declines make them more economical. However, the *AEO2013* projection is less optimistic than *AEO2012* about the ability of advanced biofuels to capture a rapidly growing share of the liquid fuels market. As a result, biomass use in *AEO2013* totals 4.2 quadrillion Btu in 2035 (compared to 5.4 quadrillion Btu in *AEO2012*) and 4.9 quadrillion Btu in 2040, up from 2.7 quadrillion Btu in 2011.

With improved efficiency of energy use and a shift away from the most carbon-intensive fuels, U.S. energy-related carbon dioxide (CO_2) emissions remain more than 5 percent below their 2005 level through 2040

Total U.S. energy-related CO_2 emissions do not return to their 2005 level (5,997 million metric tons) by the end of the *AEO2013* projection period (Figure 4). Emissions from motor gasoline demand in *AEO2013* are lower than in *AEO2012* as a result of the adoption of fuel economy standards, biofuel mandates, and shifts in consumer behavior. Emissions from coal use in the generation of electricity are lower as power generation shifts from coal to lower-carbon fuels, including natural gas and renewables.

Introduction

In preparing the *AEO2013* Reference case, the U.S. Energy Information Administration (EIA) evaluated a wide range of trends and issues that could have major implications for U.S. energy markets. This overview presents the *AEO2013* Reference case and compares it with the *AEO2012* Reference case released in June 2012 (see Table 1 on pages 15-16). Because of the uncertainties inherent in any energy market projection, the Reference case results should not be viewed in isolation. Readers are encouraged to review the alternative cases when the complete *AEO2013* publication is released, in order to gain perspective on how variations in key assumptions can lead to different outlooks for energy markets.

To provide a basis against which alternative cases and policies can be compared, the *AEO2013* Reference case generally assumes that current laws and regulations affecting the energy sector remain unchanged throughout the projection (including the implication that laws that include sunset dates do, in fact, end at the time of those sunset dates). This assumption helps increase the comparability of the Reference case with other analyses, clarifies the relationship of the Reference case to other *AEO2013* cases, and enables policy analysis with less uncertainty regarding unstated legal or regulatory assumptions.

Figure 2. Liquids consumption by light-duty vehicles in the United States, *AEO2012* and *AEO2013* Reference cases, 2010-2040 (million barrels per day)

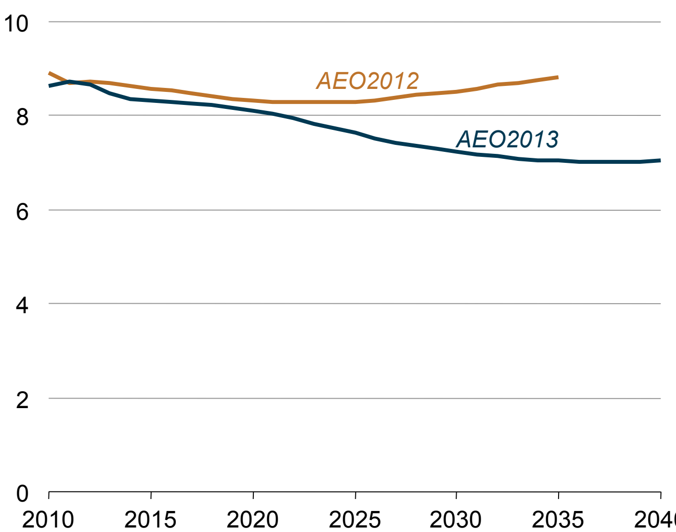
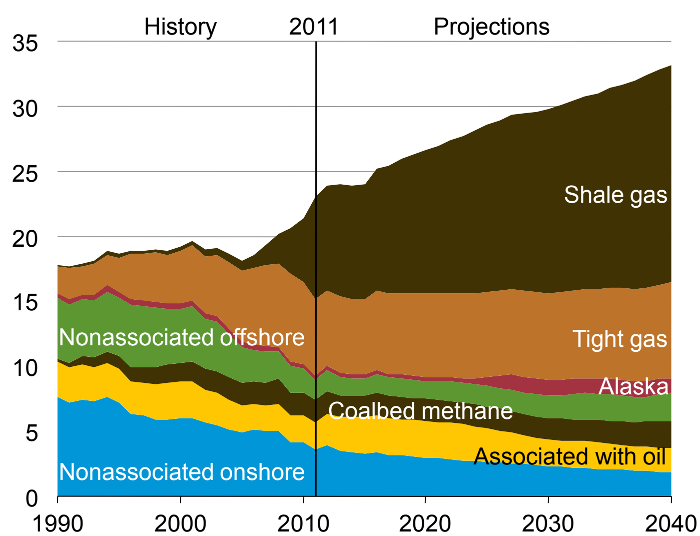


Figure 3. U.S. dry natural gas production by source, 1990-2040 (trillion cubic feet)

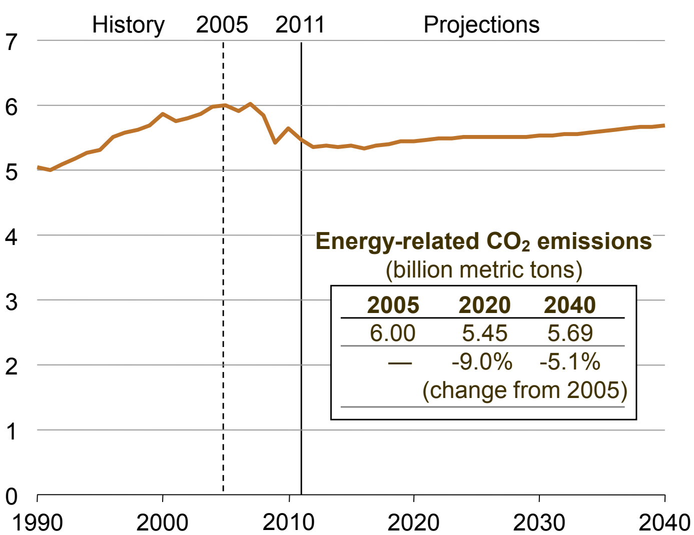


As in past editions, the complete *AEO2013* will include additional cases, many of which reflect the impacts of extending a variety of current energy programs beyond their current expiration dates and the permanent retention of a broad set of programs that currently are subject to sunset provisions. In addition to the alternative cases prepared for *AEO2013*, EIA has examined proposed policies at the request of Congress over the past few years. Reports describing the results of those analyses are available on EIA's website.[3]

Key updates made for the *AEO2013* Reference case include the following:

- Extension of the projection period through 2040, an additional five years beyond *AEO2012*.
- Adoption of a new Liquid Fuels Market Module (LFMM) in place of the Petroleum Market Module used in earlier *AEO*s provides for more granular and integrated modeling of petroleum refineries and all other types of current and potential future liquid fuels production technologies. This allows more direct analysis and modeling of the regional supply and demand effects involving crude oil and other feedstocks, current and future processes, and marketing to consumers.
- A shift to the use of Brent spot price as the reference oil price. *AEO2013* also presents the average West Texas Intermediate (WTI) spot price of light, low-sulfur crude oil delivered in Cushing, Oklahoma, and includes the U.S. annual average refiners' acquisition cost of imported crude oil, which is more representative of the average cost of all crude oils used by domestic refiners.
- A shift from using regional natural gas wellhead prices to using representative regional natural gas spot prices as the basis of the natural gas supply price. Due to this change, the methodology for estimating the Henry Hub price was revised.
- Updated handling of data on flex-fuel vehicles (FFVs) to better reflect consumer preferences and industry response. FFVs are necessary to meet the Renewable Fuels Standard (RFS), but the phasing out of CAFE credits for their sale and limited demand from consumers reduce their market penetration.
- A revised outlook for industrial production to reflect the impacts of increased shale gas production and lower natural gas prices, which result in faster growth for industrial production and energy consumption. The industries affected include, in particular, bulk chemicals and primary metals.
- Incorporation of a new aluminum process flow model in the industrial sector, which allows for diffusion of technologies through choices made among known commercial and emerging technologies based on relative capital costs and fuel expenditures and provides for a more realistic representation of the evolution of energy consumption than in previous *AEO*s.
- An enhanced industrial chemical model, in several respects: the baseline liquefied petroleum gas (LPG) feedstock data have been aligned with 2006 survey data; use of an updated propane-pricing mechanism that reflects natural gas price influences in order to allow for price competition between LPG feedstock and petroleum-based (naphtha) feedstock; and specific accounting in the Industrial Demand Model for propylene supplied by the LFMM.
- Updated handling of the U.S. Environmental Protection Agency's (EPA) National Emissions Standards for Hazardous Air Pollutants for industrial boilers and process heaters to address the maximum degree of emissions reduction using maximum achievable control technology. An industrial capital expenditure and fuel price adjustment for coal and residual fuel has been applied to reflect risk perception about the use of those fuels relative to natural gas.

Figure 4. U.S. energy-related CO_2 emissions, 1990-2040 (billion metric tons)



- Augmentation of the construction and mining models in the Industrial Demand Model to better reflect AEO2013 assumptions regarding energy efficiencies in off-road vehicles and buildings, as well as the productivity of coal, oil, and natural gas extraction.
- Adoption of final model year 2017 to 2025 GHG emissions and CAFE standards for LDVs, which increases the projected fuel economy of new LDVs to 47.3 mpg in 2025.
- Updated handling of the representation of purchase decisions for alternative fuels for heavy-duty vehicles. Market factors used to calculate the relative cost of alternative-fuel vehicles, specifically natural gas, now represent first buyer-user behavior and slightly longer breakeven payback periods, significantly increasing the demand for natural gas fuel in heavy trucks.
- Updated modeling of LNG export potential, which includes a rudimentary assessment of pricing of natural gas in international markets.

[3]See "Congressional Requests," website www.eia.gov/analysis/reports.cfm?t=138.

- Updated power generation unit costs that capture recent cost declines for some renewable technologies, which tend to lead to greater use of renewable generation, particularly solar technologies.
- Reinstatement of the Clean Air Interstate Rule (CAIR) after the court's announcement of intent to vacate the Cross-State Air Pollution Rule (CSAPR).
- Modeling of California's Assembly Bill 32, the Global Warming Solutions Act (AB 32), that allows for representation of a cap-and-trade program developed as part of California's GHG reduction goals for 2020. The coordinated regulations include an enforceable GHG cap that will decline over time. *AEO2013* reflects all covered sectors, including emissions offsets and allowance allocations.
- Incorporation of the California Low Carbon Fuel Standard, which requires fuel producers and importers who sell motor gasoline or diesel fuel in California to reduce the carbon intensity of those fuels by 10 percent between 2012 and 2020 through the increased sale of alternative low-carbon fuels.

Economic growth

The recovery from the 2008-09 recession continues on a slow path in the *AEO2013* Reference case. Consumer confidence surveys are still roughly 25 percent below prerecession levels nearly two years after the official end of the recession in 2009. The slower economic growth in the early years of the projection has implications for the long term, with a lower economic growth rate leading to a slower recovery in employment.

Table 2 compares key long-run economic growth in the *AEO2013* and *AEO2012* Reference cases to growth rates experienced during the past 30 years. Even though overall GDP growth is slightly lower in the *AEO2013* Reference case than the historical period, import growth is slower than export growth, allowing more of the domestic production to satisfy domestic demand. As a result, industrial production growth is higher in *AEO2013* than in *AEO2012*.

Beyond 2013, the economic assumptions underlying the *AEO2013* Reference case reflect trend projections that do not include short-term fluctuations. Economic growth projections for 2013 are consistent with those published in EIA's September 2012 *Short-Term Energy Outlook*.

Energy prices

Crude oil

Oil prices are influenced by a number of factors, including some elements that have mainly short-term impacts. Others, such as expectations about future world demand for petroleum and other liquids and production decisions by the Organization of

Table 2. Comparison of key economic growth rates from 2011-2040 to growth from 1980-2010 (percent per year, unless otherwise noted)

	AEO2013	*AEO2012*[1]	1980-2010
U.S. Indicators			
Real GDP	2.5	2.6	2.7
Real disposable income	2.3	2.5	2.9
Real consumer spending	2.2	2.3	3.0
Real private investment	4.0	4.2	2.8
Real exports	5.5	5.9	5.3
Real imports	3.8	4.1	6.2
Real government expenditures	0.6	0.5	2.2
Federal funds rate (average rate over period)	3.4	3.6	5.8
Unemployment rate (average rate over period)	5.9	6.4	6.3
Output per hour in nonfarm business	1.9	1.9	2.1
International Indicators			
Real GDP: Major trading countries[2]	1.8	1.8	2.4
Real GDP: Other trading countries[3]	4.0	4.2	4.5

[1]For period from 2011 to 2035.
[2]Major U.S. trading partners include Australia, Canada, Switzerland, United Kingdom, Japan, Sweden, and the Eurozone.
[3]Other trading partners include Argentina, Brazil, Chile, China, Colombia, Mexico, Hong Kong, Indonesia, India, Israel, Korea, Malaysia, Philippines, Russia, Saudi Arabia, Singapore, Thailand, Taiwan, and Venezuela.
Source: **History:** U.S. Bureau of Economic Analysis; Federal Reserve; and U.S. Bureau of Labor Statistics. **Projections:** AEO2013 National Energy Modeling System, run REF2013.D102312A; and AEO2012 National Energy Modeling System, run REF2012.D020112C.

the Petroleum Exporting Countries (OPEC), affect prices over the longer term. Supply and demand in the world oil market are balanced through responses to price movements, and the underlying supply and demand expectations are both numerous and complex. The key determinants of long-term petroleum and other liquids supply and prices can be summarized in four broad categories: the economics of non-OPEC petroleum liquids supply; OPEC investment and production decisions; the economics of other liquids supply; and world demand for petroleum and other liquids.

For *AEO2013*, the oil price is represented by spot prices for light, sweet Intercontinental Exchange Brent crude oil instead of WTI crude oil traded on NYMEX. This change was made to better reflect the price refineries pay for imported light, sweet crude oil and takes into account the divergence of WTI prices from those of globally traded benchmark crudes such as Brent. WTI prices have diverged from other benchmark crude prices because of insufficient pipeline capacity to move crude oil to and from Cushing, Oklahoma (the location at which WTI prices are quoted), and the growth of midcontinent and Canadian oil production that has overwhelmed the transportation infrastructure needed to move crude from Cushing to the U.S. Gulf of Mexico.

Among the key assumptions defining the Reference case over the projection period are average economic growth of 1.8 percent per year for major U.S. trading partners; average annual economic growth in other U.S. trading partners of 4.0 percent; and declining liquid fuels consumption per unit of GDP. The OPEC market share of total liquid fuels production remains at approximately 40 to 45 percent over the projection period. Production from non-OPEC countries increases to levels above those in *AEO2012*. In the *AEO2013* Reference case, the Brent spot oil price decreases from $111 per barrel (in 2011 dollars) in 2011 to $96 per barrel in 2015. After 2015, the Brent price increases, reaching $163 per barrel in 2040 (or about $269 per barrel in nominal dollars) as growing demand leads to the development of more costly resources (Figure 5). A wide range of price scenarios and discussion of the significant uncertainty surrounding future world oil prices will be included in the complete *AEO2013* publication released in early 2013.

Liquid products

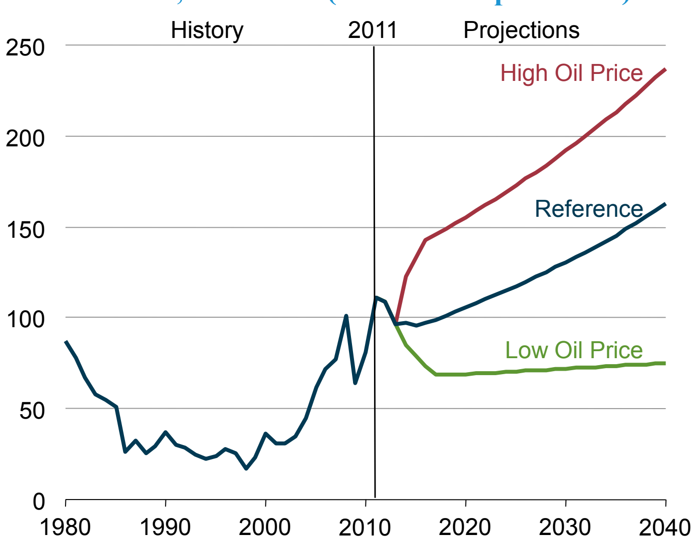
Real prices (in 2011 dollars) for motor gasoline and diesel delivered to the transportation sector in the *AEO2013* Reference case increase from $3.45 and $3.58 per gallon, respectively, in 2011 to $4.32 and $4.94 per gallon in 2040. Although both prices dip modestly over the early portion of the projection period, increases are steady thereafter. Motor gasoline prices in 2035 are slightly higher in *AEO2013* than in *AEO2012*, but diesel prices are considerably higher in 2035. The diesel share of total domestic liquids production rises, and the gasoline share falls, as a result of incorporation of the model year 2017 to 2025 GHG and CAFE standards for LDVs. Increasing demand for distillate puts pressure on refiners to increase distillate yield and results in higher prices relative to gasoline.

Natural gas

For *AEO2013*, the Henry Hub spot price is projected using a new methodology. Previously, the Henry Hub prices were based on the average national wellhead price and its historical relationship with the Henry Hub price. Given historical correlations, the projected difference between the Henry Hub price and the national average wellhead price increased as the wellhead price rose over the projection period. The Henry Hub spot prices in the *AEO2013* Reference case are based on natural gas prices that balance the supply and demand for Gulf Coast natural gas, which contributes to a lower Henry Hub price projection in *AEO2013* than in *AEO2012*.

With increasing natural gas production, reflecting continued success in tapping the nation's extensive shale gas resource, Henry Hub spot natural gas prices remain below $4 per million Btu (2011 dollars) through 2018 in the *AEO2013* Reference case. The resilience of drilling activity, despite low natural gas prices, is in part a result of high crude oil prices, which significantly improve the economics of natural gas plays that have relatively high liquids content (crude oil, lease condensates, and natural gas liquids). Also contributing to growing production volumes are improved drilling efficiencies, which result in a greater number of wells being drilled more quickly, with fewer rigs and higher initial production rates.

Figure 5. Average annual Brent spot crude oil prices in three cases, 1980-2040 (2011 dollars per barrel)



After 2018, natural gas prices increase steadily as tight gas and shale gas drilling activity expands to meet growing domestic demand for natural gas and offsets declines in natural gas production from other sources. Natural gas prices rise as lower cost resources are depleted and production gradually shifts to less productive and more expensive resources. Henry Hub spot natural gas prices (in 2011 dollars) reach $5.40 per million Btu in 2030 and $7.83 per million Btu in 2040.

Coal

The average minemouth price of coal increases by 1.4 percent per year in the *AEO2013* Reference case, from $2.04

per million Btu in 2011 to $3.08 per million Btu in 2040 (2011 dollars). The upward trend of coal prices primarily reflects an expectation that cost savings from technological improvements in coal mining will be outweighed by increases in production costs associated with moving into reserves that are more costly to mine. The upward trend in the minemouth price of coal in the *AEO2013* Reference case is similar to the trend in the *AEO2012* Reference case, but the average price through the projection period in *AEO2013* is generally higher, primarily because of the smaller share of total coal production accounted for by production from lower-cost mines in the West and higher price projections for coking coal.

Electricity

Following the recent rapid decline of natural gas prices, real average delivered electricity prices in the *AEO2013* Reference case fall from 9.9 cents per kilowatthour in 2011 to as low as 9.2 cents per kilowatthour in 2015, as natural gas prices remain relatively low. Retail electricity prices are influenced by fuel prices, particularly natural gas prices. However, the relationship between retail electricity prices and natural gas prices is complex, and many factors influence the degree to which and the timeframe over which they are linked. These factors include the share of natural gas generation in a region, the level of costs associated with electricity transmission and distribution systems not directly linked to fuel costs, the mix of competitive versus cost-of-service pricing, and the number of customers who purchase power directly from wholesale power markets. As a result, it can take time for fuel price changes to affect electricity prices, and the impacts will vary from region to region.

In the *AEO2013* Reference case, electricity prices are lower throughout the projection than they were in the *AEO2012* Reference case. Natural gas prices to electricity generators are significantly lower than those in *AEO2012* in the first few years and are between 3 percent and 5 percent lower from 2025 to 2035, while the cost of coal is higher after 2015. As a result, reliance on natural gas-fired generation in the electric power sector increases, with lower operating costs per kilowatthour than in *AEO2012*. In the long term, however, both natural gas prices and electricity prices rise. Electricity prices in 2035 are 10.1 cents per kilowatthour (2011 dollars) in the *AEO2013* Reference case, compared with 10.3 cents per kilowatthour in the *AEO2012* Reference case. In *AEO2013*, the prices continue rising to 10.8 cents per kilowatthour in 2040.

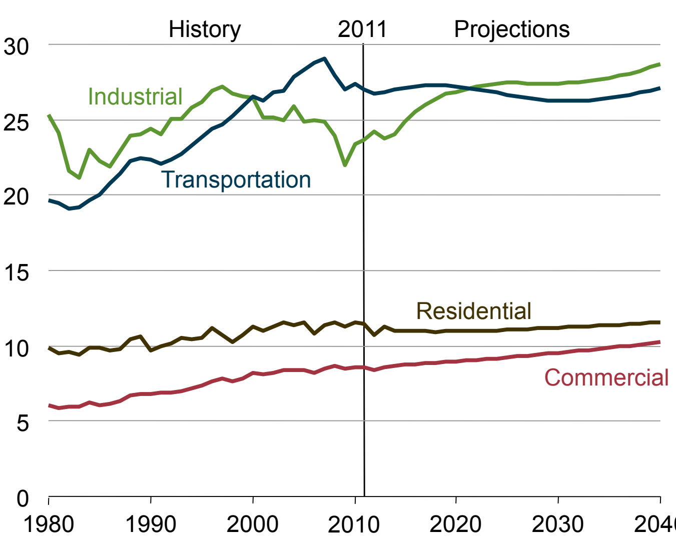
Energy consumption by sector

Transportation

Delivered energy consumption in the transportation sector remains relatively constant at about 27 quadrillion Btu from 2011 to 2040 in the *AEO2013* Reference case (Figure 6). Energy consumption by LDVs (including commercial light trucks) declines in the Reference case, from 16.1 quadrillion Btu in 2011 to 14.0 quadrillion Btu in 2025, due to incorporation of the model year 2017 to 2025 GHG and CAFE standards for LDVs. Despite the projected increase in LDV miles traveled, energy consumption for LDVs further decreases after 2025, to 13.0 quadrillion Btu in 2035, as a result of fuel economy improvements achieved through stock turnover as older, less efficient vehicles are replaced by newer, more fuel-efficient vehicles. Beyond 2035, LDV energy demand begins to level off as increases in travel demand begin to exceed fuel economy improvements in the vehicle stock.

Sales of alternative-fuel vehicles in the *AEO2013* Reference case are lower than those in *AEO2012*. The majority of the reduction relative to *AEO2012* is reflected in sales of flex-fuel vehicles (FFVs), which in 2035 are about 1.3 million, or less than one-half the 2.9 million FFV sales in the *AEO2012* Reference case. Sales of battery-powered electric vehicles also are considerably lower in the *AEO2013* Reference case than in *AEO2012*, with annual sales in 2035 estimated to be about 119,000, or 65 percent lower. Reductions in battery electric vehicles are offset by increased sales of hybrid and plug-in hybrid vehicles, which grow to about 1.3 million vehicles in 2035—about 20 percent higher than in the *AEO2012* Reference case. Continued fuel economy improvement in vehicles using other alternative fuels, gasoline, and diesel, combined with growth in the use of hybrid technologies (including micro, mild, full, and plug-in hybrid vehicles), limit the use of electric vehicles over the projection. Although about one-half of new LDV sales in 2040 use diesel, alternative fuels, or hybrid technology, only a small share, less than 1 percent, are all-electric.

Figure 6. Delivered energy consumption by sector, 1980-2040 (quadrillion Btu)



Energy demand for heavy trucks increases from 5.2 quadrillion Btu in 2011 to 7.1 quadrillion Btu in 2035 (compared with 6.2 quadrillion Btu in 2035 in the *AEO2012* Reference case) and then to 7.6 quadrillion Btu in 2040. Higher industrial output in *AEO2013* leads to greater growth in vehicle-miles traveled by freight trucks, which leads to higher energy demand by heavy vehicles in *AEO2013* as compared with *AEO2012*. Factors used to calculate the economic effectiveness of heavy-duty alternative-fuel vehicles have been updated to represent the travel behavior of first-time buyers and economic breakeven hurdles that, when coupled with very competitive natural gas prices, significantly increase demand for natural gas fuel in heavy trucks. As a result, natural gas use in heavy-duty vehicles increases to 1.7 trillion cubic feet in 2040, displacing 0.7 million barrels of liquid fuels per day. The *AEO2013* Reference case includes the GHG Emissions and Fuel Efficiency Standards for Medium- and Heavy-Duty Engines and Vehicles published by the EPA and the National Highway Traffic Safety Administration in September 2011.[4]

Industrial

Approximately one-third of total U.S. delivered energy, 24.0 quadrillion Btu, was consumed in the industrial sector in 2011. In the *AEO2013* Reference case, total industrial delivered energy consumption grows by 16 percent, to 27.8 quadrillion Btu in 2035 (0.8 quadrillion Btu higher than in the *AEO2012* Reference case) and 28.7 quadrillion Btu in 2040. The rate of growth in total industrial energy consumption is greater from 2011 to 2025 than after 2025 in *AEO2013*, as industry responds to the lower natural gas prices resulting from the expansion of shale gas production in the near term. After 2025, increased international competition and rising natural gas prices as a result of more modest growth in shale gas production lead to slower growth in industrial energy consumption. The industry that consumes the most energy is bulk chemicals, where energy consumption grows from 5.7 quadrillion Btu in 2011 to 6.6 quadrillion Btu in 2024, before declining to 6.0 quadrillion Btu in 2035 and 5.8 quadrillion Btu in 2040.

The energy-intensive industries initially exhibit strong growth in shipments and energy consumption, but most of the growth in shipments and energy consumption occurs before 2025. In 2011, the energy-intensive industries constitute 27 percent of shipments and 63 percent of industrial energy consumption. In 2040, the energy-intensive industry share of shipments falls to 20 percent, and their share of energy consumption falls to 56 percent. Shipments decline noticeably after 2025 for the aluminum, bulk chemicals, and iron and steel industries, because those industries are more affected by international competition than others. Energy use in the energy-intensive industries increases by 0.9 percent per year from 2011 to 2025 and then falls by 0.2 percent per year from 2025 to 2035.

Non-energy-intensive industries show a different pattern of shipment growth and energy consumption, in part because they are not affected as much as the energy-intensive industries by international competition and energy prices. Non-energy-intensive industry shipments and energy consumption grow throughout the period from 2011 to 2035 in the *AEO2013* Reference case, with shipments increasing by 51 percent from 2011 to 2025 and 22 percent from 2025 to 2035, and energy consumption growing at an annual rate of 1.2 percent from 2011 to 2035 (plastics is the only non-energy-intensive industry that shows a decline in energy use). However, the rate of growth in their energy consumption from 2011 to 2025 is roughly twice as high as the rate after 2025, because growth in shipments is slower after 2025. In 2035, the non-energy-intensive industries constitute 53 percent of total industrial shipments and 41 percent of industrial energy consumption.

Two new environmental policies that affect parts of the industrial sector are incorporated in the *AEO2013* Reference case. California's AB 32 is a comprehensive law limiting the state's GHG emissions, including those from stationary sources; and the extension of the National Emissions Standards for Hazardous Air Pollutants to industrial boilers and process heaters addresses the maximum degree of emission reduction possible using the maximum achievable control technology (Boiler MACT). Although both AB 32 and the Boiler MACT policies have minimal effects on industrial energy consumption, AB 32 results in a relatively low GHG allowance price, as is also shown in California's own analyses.[5]

Residential

Residential delivered energy consumption remains roughly constant in the *AEO2013* Reference case from 2011 to 2040, reflecting consumption levels lower than those in *AEO2012*. Delivered electricity consumption is 5.7 quadrillion Btu and natural gas consumption is 4.3 quadrillion Btu in 2035 in the *AEO2013* Reference case, compared with 5.9 quadrillion Btu and 4.8 quadrillion Btu, respectively, in the *AEO2012* Reference case. The lower consumption levels in the *AEO2013* Reference case are explained in part by a change in the handling of data on heating and cooling degree days in the projection. The *AEO2013* Reference case uses a 30-year trend of historical data as the basis for degree days in both the residential and commercial sectors. Previously, average data for the most recent historical decade were used to represent degree days for the projection period without reflecting any trend over time, which tended to underestimate cooling demand and overestimate heating demand. The change, in combination with updated population projections, results in 6 percent fewer population-weighted heating degree days and 12 percent more population-weighted cooling degree days in 2035, which reduces energy consumption for space heating and increases energy consumption for space cooling. Since more energy is consumed for heating than cooling, this results in a net reduction of delivered energy in *AEO2013* when compared with *AEO2012.*

The updated technology and cost parameters for residential lighting lead to lower electricity consumption. The first round of standards in the Energy Independence and Security Act of 2007 (EISA) are implemented in years 2012 through 2014, with 2014 lighting consumption about 18 percent below its 2011 level. EISA also established a second-tier standard in 2020. In the *AEO2012*

[4]U.S. Environmental Protection Agency and National Highway Traffic Safety Administration, "Greenhouse Gas Emissions Standards and Fuel Efficiency Standards for Medium- and Heavy-Duty Engines and Vehicles; Final Rule," *Federal Register*, Vol. 76, No. 179 (September 15, 2011), pp. 57106-57513, website www.gpo.gov/fdsys/pkg/FR-2011-09-15/html/2011-20740.htm.

[5]See California Environmental Protection Agency, Air Resources Board, "Allowance Price Containment Reserve Analysis," website www.arb.ca.gov/regact/2010/capandtrade10/capv3appg.pdf.

Reference case, the standard was assumed to be met with improved, halogen-type incandescent technology; but in *AEO2013*, halogen-type incandescent bulbs are not available in 2020 and beyond, and households adopt more efficient technologies, such as compact fluorescent and light-emitting diode bulbs.

Commercial

Commercial sector energy consumption grows from 8.6 quadrillion Btu in 2011 to 10.2 quadrillion Btu in 2040 in the *AEO2013* Reference case, slower than in the *AEO2012* Reference case, despite similar growth in square footage in both cases. Growth in commercial electricity consumption averages 0.8 percent per year from 2011 to 2040 in *AEO2013*, lower than the 1.0-percent average annual growth in commercial floorspace. Changing trends for personal computer adoption, increasing data center efficiency, and slower-than-expected adoption of new data centers as a result of the recent recession all lead to lower electricity consumption in the *AEO2013* Reference case than in *AEO2012*. In addition, decreasing costs for solid-state lighting technologies contribute to an increase in shipments throughout the commercial sector. Distributed generation and combined heat-and-power systems generate 63 billion kilowatthours of electricity in 2035, 47 percent more than in the *AEO2012* Reference case. Decreasing technology costs and rapidly increasing capacity in the near term, especially in existing construction, account for higher levels of electricity generation in the commercial sector in the *AEO2013* Reference case. Growth of natural gas consumption in the commercial sector continues to average roughly 0.4 percent annually in the *AEO2013* Reference case, similar to the rate in the *AEO2012* Reference case.

Energy consumption by primary fuel

Total primary energy consumption grows by 7 percent in the *AEO2013* Reference case, from 98 quadrillion Btu in 2011 to 104 quadrillion Btu in 2035—2.5 quadrillion Btu less than in *AEO2012*—and continues to grow at a rate of 0.6 percent per year, reaching about 108 quadrillion Btu in 2040 (Figure 7). The fossil fuel share of energy consumption falls from 82 percent in 2011 to 78 percent in 2040, as consumption of petroleum-based liquid fuels falls, largely as a result of the incorporation of new fuel efficiency standards for LDVs.

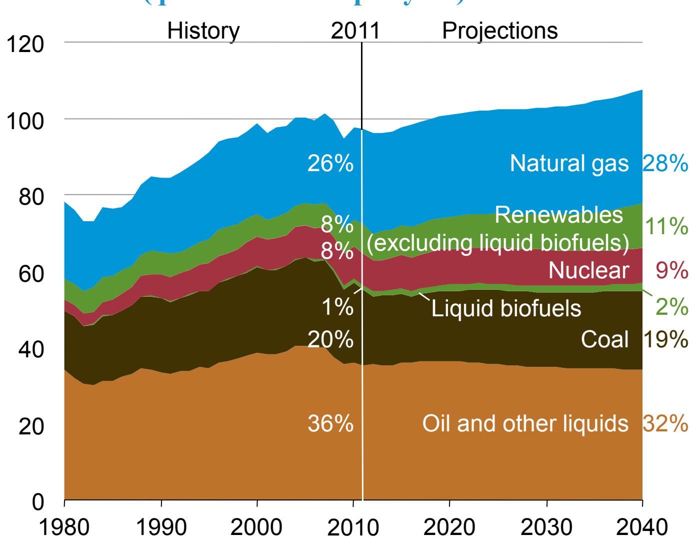
While total liquid fuels consumption falls, consumption of domestically produced biofuels increases significantly, from 1.3 quadrillion Btu in 2011 to 2.1 quadrillion Btu in 2040, and its share of total U.S. liquid fuels consumption grows from 3.5 percent in 2011 to 5.8 percent in 2040. The increases are much smaller than those in *AEO2012*, however, as a result of diminished FFV penetration, a smaller motor gasoline pool for blending ethanol, and reduced production of cellulosic biofuels, which to date has been well under the targets set by the EISA. (EPA issued waivers that substantially reduced the cellulosic biofuels obligation under the RFS for 2010, 2011, and 2012.) In addition, the production tax credit for cellulosic biofuels is scheduled to expire at the end of 2012.

Total U.S. consumption of liquid fuels, including both petroleum-based fuels and biofuels, which was 37.0 quadrillion Btu (18.9 million bpd) in 2011, increases to 37.6 quadrillion Btu (19.8 million bpd) in 2019 in the *AEO2013* Reference case, then declines to 35.8 quadrillion Btu (18.9 million bpd) in 2035 before rising to 36.1 quadrillion Btu (about 18.9 million bpd) in 2040. Biofuel consumption increases over most of the projection period. The transportation sector dominates demand for liquid fuels, although its share (as measured by energy content) declines modestly, from 71 percent of total liquids consumption in 2011 to 70 percent in 2040.

In the *AEO2013* Reference case, natural gas consumption rises from 24.4 trillion cubic feet in 2011 to 28.7 trillion cubic feet in 2035 (about 2.1 trillion cubic feet higher than in the *AEO2012* Reference case) and continues to grow to 29.5 trillion cubic feet in 2040. The largest share of the growth is for electricity generation. Demand for natural gas in the electric power sector increases from 7.6 trillion cubic feet in 2011 to approximately 9.5 trillion cubic feet in 2040, with a portion of the growth attributable to the retirement of 49 gigawatts of coal-fired capacity by 2022. Natural gas consumption in the industrial sector is also higher in *AEO2013* than was projected in *AEO2012*, due to the rejuvenation of the industrial sector as it benefits from surging shale gas production that is accompanied by slow price growth, particularly from 2011 through 2019, when the price of natural gas remains below 2010 levels. Some industries, such as bulk chemicals, are more strongly affected than others. In the residential sector, natural gas consumption declines throughout the projection period. Because natural gas is used in the residential sector directly for heating but not for cooling, residential natural gas consumption is affected by the 6-percent reduction in heating degree days described above.

Total coal consumption—including the portion of coal-to-liquids (CTL) consumed as liquids—increases from 19.7 quadrillion Btu (999 million short tons) in 2011 to 20.5

Figure 7. U.S. primary energy consumption by fuel, 1980-2040 (quadrillion Btu per year)



quadrillion Btu (1,071 million short tons) in 2040 in the *AEO2013* Reference case. Coal consumption, mostly for electric power generation, falls off through 2016. After 2016, coal-fired electricity generation increases slowly as the remaining coal-fired capacity is used more intensively, but little capacity is added. Coal consumption in the electric power sector in 2035 in the *AEO2013* Reference case is about 0.6 quadrillion Btu (23 million short tons) lower than projected in the *AEO2012* Reference case. The startup of the first CTL plants is delayed to 2023 in the *AEO2013* Reference case, with penetration of the technology far more modest than in *AEO2012*.

Total consumption of marketed renewable fuels grows by 1.6 percent per year in the *AEO2013* Reference case. Growth in consumption of renewable fuels results mainly from the implementation of the federal RFS for transportation fuels and state renewable portfolio standard (RPS) programs for electricity generation. Marketed renewable energy includes wood, municipal waste, biomass, and hydroelectricity in the end-use sectors; hydroelectricity, geothermal, municipal solid waste, biomass, solar, and wind for generation in the electric power sector; and ethanol for gasoline blending and biomass-based diesel in the transportation sector, of which 2.2 quadrillion Btu is included with liquid fuel consumption in 2040. Excluding hydroelectricity, renewable energy consumption in the electric power sector grows from 1.6 quadrillion Btu in 2011 to 4.5 quadrillion Btu in 2040, with biomass accounting for 24 percent of the growth and wind 44 percent. Generation of electricity from solar photovoltaic (PV) energy exhibits the fastest growth. Starting from a small base, PV accounts for 17 percent of total electricity generated from renewable energy sources, excluding hydropower, in 2040.

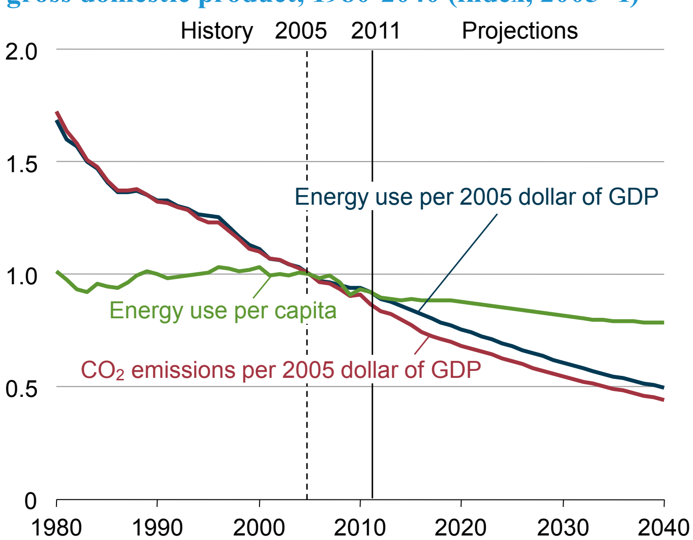
Energy intensity

Population is a key determinant of energy consumption through its influence on demand for travel, housing, consumer goods, and services. U.S. energy use per capita was fairly constant from 1990 to 2007, but it began to fall after 2007. In the *AEO2013* Reference case, energy use per capita continues to decline due to the impacts of improving energy efficiency (e.g., new appliance and CAFE standards) and changes in the ways energy is used in the U.S. economy. Total U.S. population increases by 29 percent from 2011 to 2040, but energy use grows by only 10 percent, with energy use per capita declining by 15 percent from 2011 to 2040 (Figure 8).

From 1990 to 2011, energy use per dollar of GDP declined on average by 1.7 percent per year, in large part because of shifts within the economy from manufactured goods to the service sectors, which use relatively less energy per dollar of GDP. The dollar-value increase in the service sectors (in constant dollar terms) was 16 times the corresponding increase for the industrial sector over the same period. As a result, the share of total shipments accounted for by the industrial sector fell from 30 percent in 1991 to 22 percent in 2011. In the *AEO2013* Reference case, the industrial share of total shipments reverses the earlier trend, largely due to the benefits of increased domestic production of natural gas, and increases to more than 23 percent in 2016. After 2016, however, the share resumes its decline, falling to less than 22 percent in 2040. Energy use per 2005 dollar of GDP declines by 46 percent from 2011 to 2040 in *AEO2013* as the result of a continued shift from manufacturing to services (and, even within manufacturing, to less energy-intensive manufacturing industries), rising energy prices, and the adoption of policies that promote energy efficiency.

CO_2 emissions per 2005 dollar of GDP have historically tracked closely with energy use per dollar of GDP. In the *AEO2013* Reference case, however, as lower-carbon fuels account for a larger share of total energy use, CO_2 emissions per 2005 dollar of GDP decline more rapidly than energy use per 2005 dollar of GDP, falling by 56 percent from 2005 to 2040, at an annual rate of 2.3 percent per year.

Figure 8. Energy use per capita and per dollar of gross domestic product and emissions per dollar of gross domestic product, 1980-2040 (index, 2005=1)



Energy production and imports

Net imports of energy decline both in absolute terms and as a share of total U.S. energy consumption in the *AEO2013* Reference case (Figure 9). The decline in energy imports reflects increased domestic petroleum and natural gas production, increased use of biofuels (much of which are produced domestically), and demand reductions resulting from rising energy prices and the adoption of new efficiency standards for vehicles. The net import share of total U.S. energy consumption is 9 percent in 2040, compared with 19 percent in 2011 (the share was 30 percent in 2005).

Liquids

U.S. production of crude oil in the *AEO2013* Reference case increases from 5.7 million bpd in 2011 to 7.5 million bpd in 2019, 13 percent higher than in *AEO2012* (Figure 10). Despite a decline after 2019, U.S. crude oil production remains above 6.0 million bpd through 2040. Higher production volumes result mainly from increased onshore oil production, predominantly from tight (very low permeability) formations.

In *AEO2013*, onshore tight oil production accounts for 51 percent of total lower 48 onshore oil production in 2040, up from 33 percent in 2011. As with shale gas, the application of horizontal drilling and hydraulic fracturing significantly increases the development of tight oil resources. Offshore crude oil production trends upward over time, fluctuating between 1.4 and 1.8 million bpd, as the pace of development activity quickens and new large development projects, predominantly in the deepwater and ultradeepwater portions of the Gulf of Mexico, are brought into production.

The faster growth of tight oil production through 2020 in *AEO2013* results in higher domestic crude oil production than in *AEO2012* throughout most of the projection. Tight oil production declines after 2020 as more development moves into lower-productivity areas (with lower initial production rates and flatter decline curves), resulting in flattening of production after 2030. Total U.S. liquids production in *AEO2013* is higher than in *AEO2012* due to increased tight oil production through 2025; however, lower production of biofuels and natural gas plant liquids, as well as the decline in tight oil production beginning in 2021, results in lower levels of total domestic liquids production after 2025 in *AEO2013* than in *AEO2012*.

U.S. dependence on imported liquid fuels continues to decline in the *AEO2013* Reference case, primarily as a result of increased domestic oil production. Imported liquid fuels as a share of total U.S. liquid fuel use reached 60 percent in 2005 before dipping below 50 percent in 2010 and falling further to 45 percent in 2011. The import share continues to decline to 34 percent in 2019 and then rises to about 37 percent in 2040, due to a decline in domestic production of tight oil that begins in about 2021 (Figure 11).

Natural gas

Cumulative production of dry natural gas from 2011 through 2035 in the *AEO2013* Reference case is about 8 percent higher than in *AEO2012*, primarily reflecting continued increases in shale gas production that result from the dual application of horizontal drilling and hydraulic fracturing. Another contributing factor is ongoing drilling in shale and other plays with high concentrations of natural gas liquids and crude oil, which, in energy-equivalent terms, have a higher value than dry natural gas. Cumulative production levels for tight gas and coalbed methane exceed those in the *AEO2012* Reference case through 2035 by 3 percent and make material contributions to the overall increase in production. Lower 48 offshore natural gas production fluctuates between 1.8 and 2.8 trillion cubic feet per year, about the same as in *AEO2012*. New, larger-volume development projects, particularly in the deepwater Gulf of Mexico, remain directed principally toward liquids rather than natural gas. Offshore natural gas production is expected to reverse a years-long overall decline in about 2015, however, after which annual volumes generally increase to 2.8 trillion cubic feet in 2035 and remain at about that level through the balance of the projection period.

In the *AEO2013* Reference case, the United States becomes a net exporter of LNG starting in 2016, as it did in the *AEO2012*

Figure 9. Total energy production and consumption, 1980-2040 (quadrillion Btu)

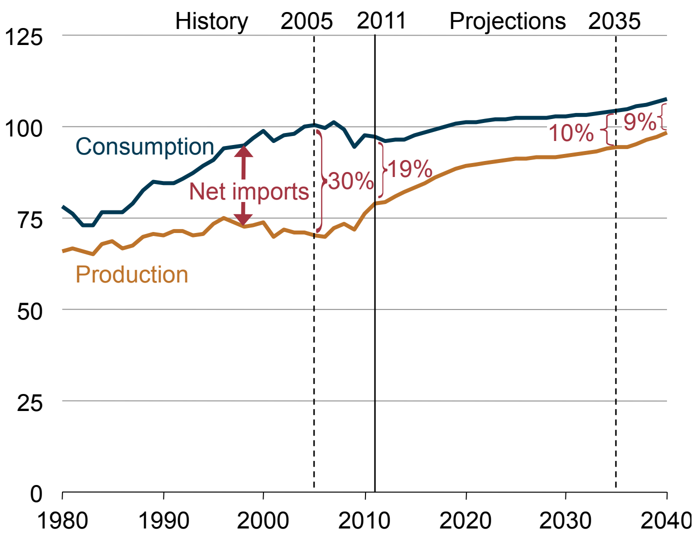


Figure 10. U.S. energy production by fuel, 1980-2040 (quadrillion Btu)

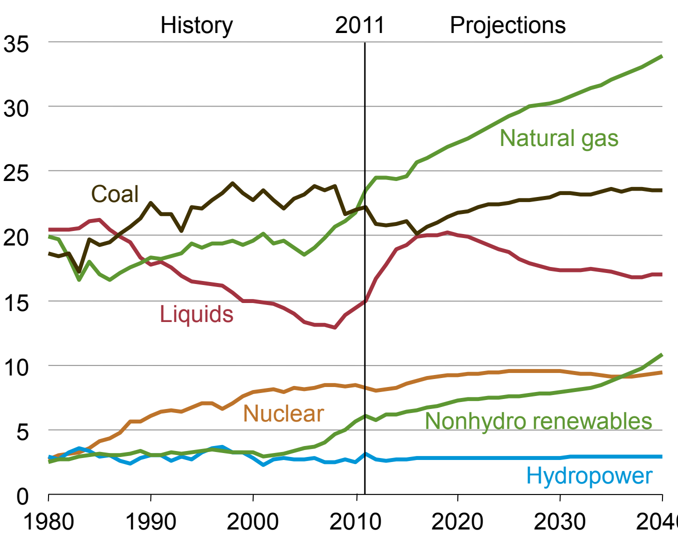
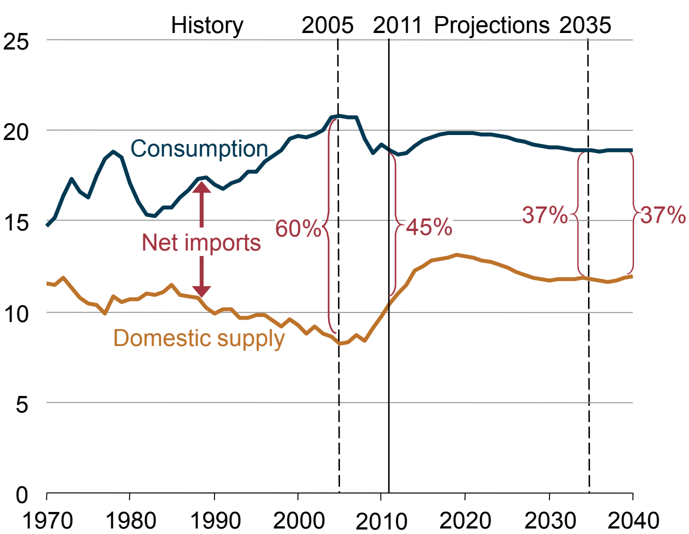


Figure 11. U.S. liquid fuels supply, 1970-2040 (million barrels per day)



Reference case, and an overall net exporter of natural gas in 2020, two years earlier than in *AEO2012*. U.S. exports of LNG from new liquefaction capacity are assumed to start at a level of 0.6 billion cubic feet per day in 2016 and increase to 4.5 billion cubic feet per day in 2027, as peak export volumes are shipped out of facilities in the Gulf Coast and Alaska. Over the projection period, cumulative net pipeline imports of natural gas from Canada and Mexico in the *AEO2013* Reference case are considerably lower than those projected in the *AEO2012* Reference case, with the United States becoming a net pipeline exporter of natural gas in 2021, or three years earlier than in *AEO2012*. In the *AEO2013* Reference case, net pipeline imports from Canada fall steadily over most of the projection period, and net pipeline exports to Mexico grow by 387 percent. U.S. cumulative net LNG exports from 2011 through 2035 are up by 69 percent in *AEO2013* compared with *AEO2012*, due in part to increased use of LNG in markets outside North America, strong domestic production, and low U.S. natural gas prices relative to other global markets. As in the *AEO2012* Reference case, the Alaska natural gas pipeline is not constructed in the *AEO2013* Reference case, because assumed high capital costs and low natural gas prices in the lower 48 states make it uneconomical to proceed with the pipeline project over the projection period.

Coal

While coal remains the leading fuel for U.S. electricity generation, its share of total generation in all years is slightly lower in the *AEO2013* Reference case than was projected in the *AEO2012* Reference case, and coal consumption in the electricity sector is lower than in *AEO2012* in most years of the projection period. While still growing in most years after 2016, coal consumption in the power sector and for the production of coal-based synthetic liquids increases more slowly than in *AEO2012*; however, higher coal exports combined with lower imports keep the differences in coal production between the *AEO2013* and *AEO2012* Reference cases relatively small.

In the *AEO2013* Reference case, domestic coal production increases at an average rate of only 0.2 percent per year, from 22.2 quadrillion Btu (1,096 million short tons) in 2011 to 23.5 quadrillion Btu (1,167 million short tons) in 2040. Over the projection period, however, production growth is uneven. From 2011 to 2016, low natural gas prices and the retirement of a sizable amount of coal-fired generating capacity lead to a substantial decline in electricity sector coal consumption, which, in turn, contributes to a 2.0-quadrillion-Btu decline in coal production over those years. After 2016, increases in coal use for electricity generation and exports lead to a gradual recovery in U.S. coal production. From 2016 to 2040, coal production grows at an average rate of 0.6 percent per year, from 20.2 quadrillion Btu to 23.5 quadrillion Btu. Regionally, coal producers in both the Interior and Western regions see their shares of total U.S. coal production increase over the projection period, while Appalachia's share declines. From 2011 to 2040, the Appalachian region's share of total coal production (on a Btu basis) falls from 38 percent to 32 percent.

Electricity generation in 2011 accounts for 91 percent of total U.S. coal consumption on a Btu basis. In the *AEO2013* Reference case, projected coal consumption in the electric power sector in 2035 (18.5 quadrillion Btu) is 0.6 quadrillion Btu lower than in the *AEO2012* Reference case (19.0 quadrillion Btu). The reduced outlook for coal consumption in this sector is generally attributable to lower natural gas prices and higher coal prices that, taken together, support increased generation from natural gas in the *AEO2013* Reference case. More generation from nonhydroelectric renewables also contributes to the reduced outlook for electricity sector coal consumption in *AEO2013*. Coal consumed at CTL plants is lower in this year's outlook, reaching 0.2 quadrillion Btu in 2035 as compared with 1.2 quadrillion Btu in *AEO2012*. With a more robust outlook for coal imports by Asian countries, *AEO2013* shows higher U.S. coal exports than *AEO2012*.

Total U.S. coal consumption increases from 19.7 quadrillion Btu in 2011 to 20.4 quadrillion Btu in 2040, reflecting average growth of 0.1 percent per year. As with production, growth rates for coal consumption are uneven over the projection, with consumption declining by 2.7 percent per year from 2011 to 2016, but then increasing by 0.7 percent per year from 2016 to 2040.

Electricity generation

Total electricity consumption in the *AEO2013* Reference case, including both purchases from electric power producers and on-site generation, grows from 3,841 billion kilowatthours in 2011 to 4,930 billion kilowatthours in 2040, an average annual rate of 0.9 percent—about the same rate as in the *AEO2012* Reference case through 2035.

The combination of slow growth in electricity demand, competitively priced natural gas, programs encouraging renewable fuel use, and the implementation of new environmental rules dampens future coal use. The *AEO2013* Reference case assumes implementation of the CAIR as a result of an August 2012 federal court decision to vacate the CSAPR. The lower natural gas prices in the early years of the *AEO2013* Reference case result in switching from coal to natural gas-fired generation, more than offsetting any increase in coal-fired generation that might have occurred in the absence of CSAPR. *AEO2013* continues to model the implementation of the Mercury and Air Toxics Standards (MATS), although the implementation date is assumed to move from 2015 to 2016 due to the large number of plants requesting extensions to comply. Once MATS is in place, SO_2 levels are reduced to well below the levels resulting from either CAIR or CSAPR.

Coal remains the largest energy source for electricity generation throughout the projection period, but its share of total generation declines from 42 percent in 2011 to 35 percent in 2040 (Figure 12). Market concerns about GHG emissions continue to dampen the expansion of coal-fired capacity in the *AEO2013* Reference case, even under current laws and policies. Low projected fuel prices for new natural gas-fired plants also affect the relative economics of coal-fired capacity, as does the continued rise in construction costs for new coal-fired power plants. As retirements far outpace new additions, total coal-fired generating capacity falls from 318 gigawatts in 2011 to 278 gigawatts in 2040 in the *AEO2013* Reference case.

Electricity generation using natural gas is higher in the *AEO2013* Reference case than was projected in the *AEO2012* Reference case because of lower projected natural gas prices. New natural gas-fired plants also are much cheaper to build than new renewable or nuclear plants. In 2016, the year that MATS is assumed to be implemented and coal-fired generation hits its lowest point, natural gas-fired generation in *AEO2013* is 10 percent higher than in *AEO2012* (and in 2035 it is still 9 percent higher).

Electricity generation from nuclear power plants grows by 14 percent in the *AEO2013* Reference case, from 790 billion kilowatthours in 2011 to 903 billion kilowatthours in 2040, accounting for about 17 percent of total generation in 2040 (compared with 19 percent in 2011). Nuclear generating capacity increases from 101 gigawatts in 2011 to a high of 114 gigawatts in 2025 through a combination of new construction (5.5 gigawatts), uprates at existing plants (8.0 gigawatts), and retirements (0.6 gigawatts). After 2025, retirements outpace additions, resulting in a slight decline to 113 gigawatts in 2040. *AEO2013* incorporates the latest information about planned nuclear plant construction and continues to use the updated estimate of the potential for capacity uprates at existing units developed for *AEO2012*. About 7 gigawatts of existing nuclear capacity is retired, primarily after 2030, because not all owners of existing nuclear capacity are expected to apply for and receive license renewals to operate their plants beyond 60 years.

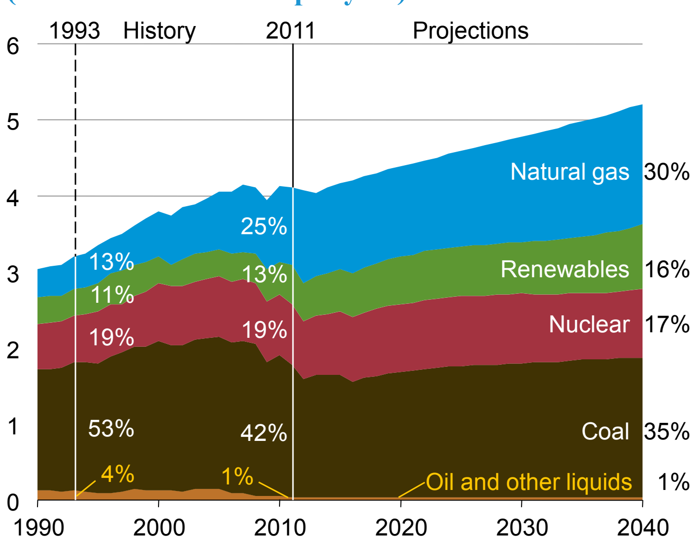
Increased generation from renewable energy, excluding hydropower, accounts for 32 percent of the overall growth in electricity generation from 2011 to 2040. Generation from renewable resources grows in response to federal tax credits, state-level policies, and federal requirements to use more biomass-based transportation fuels, some of which can produce electricity as a byproduct of their production process. Capital costs for new technologies were updated for *AEO2013*, resulting in fairly significant initial cost reductions for wind (13 percent) and solar PV (22 percent) relative to *AEO2012*. Reported renewable capacity already under construction has increased in recent years and is represented in *AEO2013*. Growth in renewable generation is supported by many state requirements, as well as new regulations on CO_2 emissions in California. The share of U.S. electricity generation coming from renewable fuels (including conventional hydropower) grows from 13 percent in 2011 to 16 percent in 2040. In the *AEO2013* Reference case, federal subsidies for renewable generation are assumed to expire as enacted. Extensions of such subsidies could have a large impact on renewable generation. The long-run projections for renewable capacity are also sensitive to natural gas prices and the relative costs of alternative generation sources.

Energy-related CO_2 emissions

Total U.S. energy-related CO_2 emissions do not return to their 2005 level (5,997 million metric tons) by the end of the *AEO2013* projection period.[6] Growth in demand for transportation fuels is moderated by rising fuel prices and new, stricter federal CAFE standards for model years 2017 to 2025, which reduce transportation emissions from 2018 until they begin to rise near the end of the projection period. Transportation emissions in 2040 are 26 million metric tons below the 2011 level. Largely as a result of the inclusion of the new CAFE standards in *AEO2013*, transportation-related CO_2 emissions in 2035 are 94 million metric tons below their level in the *AEO2012* Reference case.

State RPS requirements and abundant low-cost natural gas help shift the fuel mix for electricity generation away from coal and reduce emissions in both the residential and commercial sectors from the levels in *AEO2012*. Growth in residential sector emissions is flat over the projection period, and commercial sector emissions rise only slightly, by 0.3 percent annually.

Figure 12. Electricity generation by fuel, 1990-2040 (trillion kilowatthours per year)

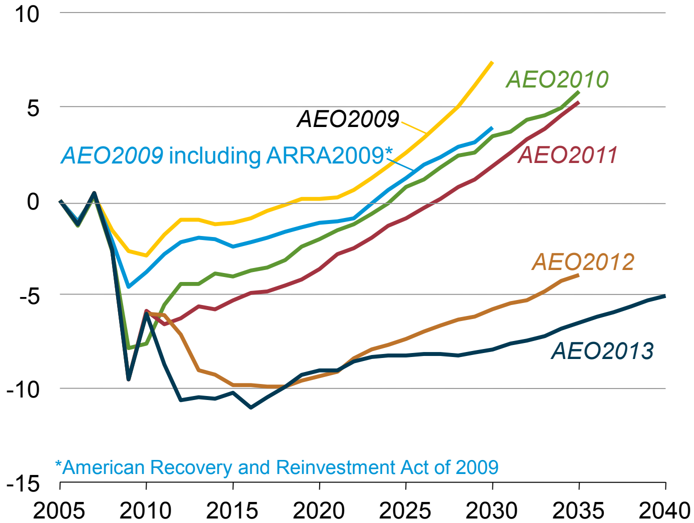


Only industrial energy-related CO_2 emissions are higher in *AEO2013* as compared to *AEO2012*. While industrial coal emissions in *AEO2013* are 48 million metric tons lower than in *AEO2012* by 2035, natural gas emissions from the industrial sector are 67 million metric tons higher by 2035, and electricity-related emissions allocated to the industrial sector are 77 million metric tons higher. With emissions from petroleum slightly lower, the net result is that industrial sector emissions are 80 million metric tons higher in the *AEO2013* Reference case than in *AEO2012*. Over the projection period from 2011 to 2040, industrial emissions grow at a rate of 0.3 percent annually.

The projected growth rate for U.S. energy-related CO_2 emissions has declined successively in each *Annual Energy Outlook* since *AEO2005* (see Figure 13, which shows projections starting with *AEO2009*), reflecting both market and policy drivers. Using 2030 as a common year, the *AEO2006* projection for total energy-related CO_2 emissions was 8,114 million metric tons, with coal accounting for 3,226

[6]The year 2005 is the base year for the Obama Administration's goal for emission reductions of 17 percent by 2020. In 2020, energy-related CO_2 emissions in the *AEO2013* Reference case are 9 percent below their 2005 level.

Figure 13. U.S. energy-related carbon dioxide emissions in recent *AEO* Reference cases (percent change from 2005)



million metric tons (40 percent) and natural gas 1,452 million metric tons (18 percent). In *AEO2010*, total energy-related CO_2 emissions had dropped to 6,176 million metric tons in 2030, with 2,296 million metric tons (37 percent) coming from coal and 1,315 million metric tons (21 percent) from natural gas. In *AEO2013*, the 2030 values have fallen to 5,523 million metric tons for total energy-related CO_2 emissions, with 1,874 million metric tons (34 percent) coming from coal and 1,468 metric tons (27 percent) from natural gas. The change reflects both market and policy factors, including the adoption of tighter economy fuel standards, the implementation of efficiency standards, and a continued shift to less carbon-intensive fuels.

List of Acronyms

AB 32	Global Warming Solutions Act of 2006
AEO	*Annual Energy Outlook*
AEO2011	*Annual Energy Outlook 2011*
AEO2012	*Annual Energy Outlook 2012*
AEO2013	*Annual Energy Outlook 2013*
bpd	barrels per day
Btu	British thermal units
CAFE	Corporate average fuel economy
CAIR	Clean Air Interstate Rule
CHP	Combined heat and power
CO_2	Carbon dioxide
CTL	Coal-to-liquids
CSAPR	Cross-State Air Pollution Rule
EIA	U.S. Energy Information Administration
EISA2007	Energy Independence and Security Act of 2007
EOR	Enhanced oil recovery
EPA	U.S. Environmental Protection Agency
FFV	Flex-fuel vehicle
GDP	Gross domestic product
GHG	Greenhouse gas
GTL	Gas-to-liquids
LDVs	Light-duty vehicles
LFMM	Liquid Fuel Market Module
LNG	Liquefied natural gas
MACT	Maximum achievable control technology
MATS	Mercury and Air Toxics Standards
mpg	miles per gallon
NGL	Natural gas liquids
NHTSA	National Highway Traffic Safety Administration
NO_X	Nitrogen oxides
OCS	Outer Continental Shelf
OECD	Organization for Economic Cooperation and Development
OPEC	Organization of the Petroleum Exporting Countries
PV	Photovoltaics
RFS	Renewable fuel standard
RPS	Renewable portfolio standard
SO_2	Sulfur dioxide
TRR	Technically recoverable resource
USGS	United States Geological Survey
WTI	West Texas Intermediate

Table 1. Comparison of projections in the *AEO2013* and *AEO2012* Reference cases, 2010-2040

			2025		2035		2040
Energy and economic factors	2010	2011	*AEO2013*	*AEO2012*	*AEO2013*	*AEO2012*	*AEO2013*
Primary energy production (quadrillion Btu)							
Petroleum	14.37	15.05	18.70	17.69	17.27	16.82	17.01
Dry natural gas	21.82	23.51	29.22	26.91	32.04	28.60	33.87
Coal	22.04	22.21	22.54	22.25	23.60	24.14	23.54
Nuclear/Uranium	8.43	8.26	9.54	9.60	9.14	9.28	9.44
Hydropower	2.54	3.17	2.86	2.99	2.90	3.04	2.92
Biomass	4.05	4.05	5.27	6.26	5.83	9.07	6.96
Other renewable energy	1.31	1.58	2.32	2.22	2.91	2.81	3.84
Other	0.76	1.20	0.85	0.69	0.90	0.91	0.89
Total	**75.31**	**79.02**	**91.29**	**88.61**	**94.59**	**94.67**	**98.46**
Net imports (quadrillion Btu)							
Liquid fuels and other petroleum[a]	20.53	18.62	15.89	15.85	16.00	16.09	15.99
Natural gas (- indicates exports)	2.69	2.02	-1.56	-0.76	-2.53	-1.33	-3.55
Coal/other (- indicates exports)	-1.58	-2.32	-3.02	-1.75	-3.32	-2.32	-2.95
Total	**21.64**	**18.31**	**11.31**	**13.34**	**10.14**	**12.44**	**9.49**
Consumption (quadrillion Btu)							
Liquid fuels and other petroleum[a]	37.76	37.02	36.87	36.58	35.82	37.70	36.07
Natural gas	24.32	24.91	27.28	26.14	29.06	27.26	29.83
Coal	20.81	19.66	19.35	20.02	20.09	21.15	20.35
Nuclear/Uranium	8.43	8.26	9.54	9.60	9.14	9.28	9.44
Hydropower	2.54	3.17	2.86	2.99	2.90	3.04	2.92
Biomass	2.87	2.74	3.82	4.17	4.23	5.44	4.91
Other renewable energy	1.31	1.58	2.32	2.22	2.91	2.81	3.84
Other	0.31	0.35	0.30	0.28	0.26	0.24	0.29
Total	**98.35**	**97.70**	**102.34**	**101.99**	**104.41**	**106.93**	**107.64**
Liquid fuels (million barrels per day)							
Domestic crude oil production	5.47	5.67	6.79	6.40	6.26	5.99	6.13
Other domestic production	4.25	4.74	5.63	5.75	5.56	6.75	5.83
Net imports	9.43	8.51	7.08	7.14	7.06	7.25	7.00
Consumption	19.17	18.95	19.50	19.20	18.86	19.90	18.95
Natural gas (trillion cubic feet)							
Dry gas production + supplemental gas	21.40	23.06	28.65	26.34	31.41	27.99	33.21
Net imports (- indicates exports)	2.60	1.95	-1.58	-0.79	-2.55	-1.36	-3.55
Consumption	23.78	24.37	26.87	25.53	28.71	26.63	29.54
Coal (million short tons)							
Production and waste coal	1,098	1,108	1,134	1,134	1,194	1,231	1,195
Net exports	64	96	124	71	136	94	123
Consumption	1,049	999	1,010	1,063	1,058	1,137	1,071

Table 1. Comparison of projections in the *AEO2013* and *AEO2012* Reference cases, 2010-2040 (continued)

Energy and economic factors	2010	2011	2025 AEO2013	2025 AEO2012	2035 AEO2013	2035 AEO2012	2040 AEO2013
Prices (2011 dollars)							
Brent spot crude oil (dollars per barrel)	81.31	111.26	117.36	--	145.41	--	162.68
West Texas Intermediate spot crude oil (dollars per barrel)	81.08	94.86	115.36	135.35	143.41	148.03	160.68
Natural gas at Henry Hub (dollars per million Btu)	4.46	3.98	4.87	5.75	6.32	7.52	7.83
Domestic coal at minemouth (dollars per short ton)	36.37	41.16	52.02	44.97	58.57	51.59	61.28
Average electricity price (cents per kilowatthour)	10.0	9.9	9.5	9.9	10.1	10.3	10.8
Economic indicators							
Real gross domestic product (billion 2005 dollars)	13,063	13,299	18,985	19,185	24,095	24,539	27,277
GDP chain-type price index (2005 = 1.000)	1.110	1.134	1.429	1.424	1.713	1.758	1.871
Real disposable personal income (billion 2005 dollars)	10,017	10,150	14,259	14,286	17,752	18,217	19,785
Value of industrial shipments (billion 2005 dollars)	5,842	6,019	8,548	7,973	9,779	8,692	10,616
Primary energy intensity (thousand Btu per 2005 dollar of GDP)	7.53	7.35	5.39	5.32	4.33	4.36	3.95
Energy-related carbon dioxide emissions (million metric tons)	5,634	5,471	5,501	5,552	5,607	5,758	5,691

[a]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.

-- = not applicable.

Notes: Quantities reported in quadrillion Btu are derived from historical volumes and assumed thermal conversion factors. Other production includes liquid hydrogen, methanol, and some inputs to refineries. Net imports of petroleum include crude oil, petroleum products, unfinished oils, alcohols, ethers, and blending components. Other net imports include coal coke and electricity. Both coal consumption and coal production include waste coal consumed in the electric power and industrial sectors.

Sources: AEO2013 National Energy Modeling System, run REF2013.D102312A; and AEO2012 National Energy Modeling System, run REF2012.D020112C.