Short-Term Energy Outlook (STEO)

Forecast Highlights

- This edition of the *Short-Term Energy Outlook* is the first to include forecasts for 2018.

- Benchmark North Sea Brent crude oil spot prices averaged $53/barrel (b) in December, a $9/b increase from November. This was the first month since July 2015 in which Brent spot prices averaged more than $50/b.

- Brent crude oil prices are forecast to average $53/b in 2017 and $56/b in 2018. West Texas Intermediate (WTI) crude oil prices are forecast to average $1/b less than Brent in both 2017 and 2018. The current values of futures and options contracts suggest high uncertainty in the price outlook. For example, EIA's forecast for the average WTI price in December 2017 of $53/b should be considered in the context of NYMEX contract values for December 2017 delivery. Contracts traded during the five-day period ending January 5 suggest the market expects WTI prices could range from $35/b to $93/b (at the 95% confidence interval) in December 2017.

- U.S. regular gasoline retail prices are expected to increase from an average of $2.25/gallon (gal) in December to $2.31/gal in the first quarter of 2017. U.S. regular gasoline retail prices are forecast to average $2.38/gal in 2017 and $2.41/gal in 2018.

- U.S. crude oil production averaged an estimated 8.9 million barrels per day (b/d) in 2016 and is forecast to average 9.0 million b/d in 2017 and 9.3 million b/d in 2018. The forecast increases in production largely reflect increases in federal offshore Gulf of Mexico production. Rising tight oil production, which results from increases in drilling activity, rig efficiency, and well-level productivity, also contributes to forecast U.S. production growth.

- Dry natural gas production is estimated to have averaged 72.4 billion cubic feet per day (Bcf/d) in 2016, a decline of 1.8 Bcf/d (2.4%) from 2015, which would be the first time annual average natural gas production has fallen since 2005. Forecast dry natural gas production increases by an average of 1.4 Bcf/d in 2017 and by 2.8 Bcf/d in 2018.

- The Henry Hub natural gas spot price averaged $2.51/million British thermal units (MMBtu) in 2016 and is expected to increase to an average of $3.55/MMBtu in 2017 and $3.73/MMBtu in 2018. Higher average prices in 2017 reflect price increases in the second half of 2016 because of a hot summer and declining production, which reduced the inventory excess compared with the previous five-year average.

- EIA estimates the annual average share of U.S. total utility-scale electricity generation from natural gas was 34% in 2016 and the share from coal was 30%, marking the first time that a fuel other than coal provided the largest share of electricity generation on an annual basis. The generation shares of coal and natural gas are expected to be roughly equal in 2017, as both fuels are projected to generate about 32% of electricity. In 2018, natural gas and coal generate 33% and 32% of electricity, respectively.

- The forecast shares of electricity generation fuels from other energy sources are expected to change modestly. Nuclear power is estimated to have generated 20% of electricity in 2016 and is projected to fall slightly to 19% of generation in 2018. Nonhydropower renewables are estimated to have generated 8% of electricity in 2016 and to grow to 9% of generation in 2018. Hydropower's share of electricity generation from 2016 through 2018 is expected to remain between 6% and 7%.

Global Liquid Fuels

EIA estimates that global petroleum and other liquid fuels inventory builds averaged 0.9 million b/d in 2016. The annual average inventory build in 2016 marked the third consecutive year of inventory builds. The pace of inventory builds is expected to slow considerably to an annual average of 0.3 million b/d in 2017 and 0.1 million b/d in 2018. However, inventories are forecast to draw by an average of 0.1 million b/d in the second half of 2018.

Continuing global oil inventory builds contribute to crude oil prices remaining below $60/b through the end of 2018. Brent crude oil prices averaged $44/b in 2016, down from an average of $52/b in 2015, However, Brent prices rose in the second half of 2016 and averaged $53/b in December. The price increase in late 2016 at least partly reflects tighter balances than previously forecast during mid-2016, along with negotiations and the eventual agreement among members of the Organization of the Petroleum Exporting Countries (OPEC) to cut crude oil production starting in January 2017.

Brent prices are expected to remain near current levels through 2017, averaging $53/b for the year. The responsiveness of U.S. tight oil production to rising oil prices in late 2016 is expected to limit significant upward oil price pressures this year. In 2018, Brent prices are forecast to rise to an average of $56/b, ending the year at $59/b in December. Upward price pressures are expected to emerge in mid-2018 as the oil market becomes more balanced.

Significant upward revisions to historical consumption in the countries of the Organization for Economic Cooperation and Development (OECD) in mid-2016 have led to a revision in the historical global balances. Based on these revisions, EIA now estimates there was a global oil inventory draw during the third quarter of 2016, which was the first quarterly draw since late 2013. EIA's previous estimates had global markets close to balance in mid-2016, but still showed inventory builds. The draw during the third quarter of 2016 was more than offset by the sizeable builds in the first and last quarters of the year, leading to an annual average build in inventories. The fourth quarter build came amid significant production increases by a number of OPEC producers ahead of announced production cuts set to take effect in January 2017, a 0.2 million b/d quarter-over-quarter increase in U.S. crude oil production, and a seasonal downturn in demand.

Global Petroleum and Other Liquid Fuels Consumption. Global consumption of petroleum and other liquid fuels averaged 95.6 million b/d in 2016, an increase of 1.4 million b/d from 2015. Consumption growth in 2016 was driven by non-OECD countries. Consumption growth is expected to be about 1.6 million b/d in 2017 and 1.5 million b/d in 2018, with 1.2 million b/d of the growth in both years coming from rising non-OECD consumption. Forecast growth in the consumption of hydrocarbon gas liquids (HGL) is an important driver of overall global liquid fuels consumption growth.

China and India are expected to be the largest contributors to non-OECD petroleum consumption growth. China's consumption growth is forecast to average 0.3 million b/d in both 2017 and 2018. China's growth in consumption of petroleum and other liquid fuels is driven by increased use of gasoline, jet fuel, and HGL, which more than offsets decreases in diesel consumption. Last year's significant rise in the use of HGL in China will continue through at least 2017 as new propane dehydrogenation (PDH) plants contribute to rising propane use. In India, consumption growth averaging 0.2 million b/d in both 2017 and 2018 is expected to result from increased use of transportation fuels and of naphtha and ethane for new petrochemical projects.

In addition to increases in China and India, consumption growth in the Middle East is forecast to average 0.3 million b/d in both 2017 and 2018, up from 0.1 million b/d in 2016. Saudi Arabia is a key contributor to this growth. Although Saudi Arabia decreased the use of crude oil for electricity generation in 2016 by burning more natural gas, the expected increased use of natural gas as a petrochemical feedstock in 2017 and 2018 will once again result in an increase of direct crude oil burn for electricity generation.

OECD petroleum and other liquid fuels consumption rose by 0.3 million b/d in 2016. In 2017, EIA forecasts OECD consumption growth to average 0.4 million b/d as increasing consumption in the United States, Europe, and South Korea drive overall OECD consumption growth. In 2018, consumption growth slows to 0.3 million b/d. Although U.S. consumption growth accelerates in 2018, it is partially offset by a shift in Europe to declining consumption. Consumption in Japan declines by about 0.1 million b/d in both 2017 and 2018.

Forecast U.S. total liquid fuels consumption increases by 0.3 million b/d in 2017 and by 0.4 million b/d in 2018. In 2017, increasing use of gasoline and distillate fuel spur U.S. consumption growth. In 2018, forecast growth is mainly the result of increased use of HGL, which is forecast to increase by 0.2 million b/d. Rising ethane consumption accounts for almost all of this increase, as several new ethane crackers are expected to come online during the forecast period.

Non-OPEC Petroleum and Other Liquid Fuels Supply. EIA estimates that petroleum and other liquid fuels production in non-OPEC oil producing countries decreased by 0.6 million b/d in 2016, with more than half of the decrease occurring in North America. However, EIA expects non-OPEC production to rise by 0.4 million b/d in 2017 and by 0.7 million b/d in 2018, as total U.S. liquid fuels production increases by 0.3 million b/d and by 0.7 million b/d, in those respective years, in response to rising oil prices and increases in drilling productivity.

Among non-OPEC producers excluding the United States, declining oil production in some areas is expected to be countered by rising production in other areas. Some of the largest declines are expected to be in the North Sea and Mexico. Production in Norway and the United Kingdom, both of which posted increases in 2016, is expected to fall in the next two years, with total North Sea liquids production declining by more than 0.1 million b/d in 2017 and by almost 0.2 million b/d in 2018. In Mexico, liquids production is forecast to decline by more than 0.1 million b/d in both 2017 and 2018.

The largest production decline outside of the United States in 2016 was in China, which fell by about 0.3 million b/d. EIA expects China's output to continue to decline throughout the forecast period by 0.1 million b/d in both in 2017 and 2018 because of investment cuts and relatively few new offshore developments.

Canadian oil production in 2016 was roughly flat compared with the previous year because of production lost to wildfires in Alberta during May, June, and July. Curtailed output in mid-2016, effectively erased all of the increases in annual average Canadian output during the year. However, Canadian production is expected to increase by about 0.2 million b/d in both 2017 and 2018. The expected growth in Canadian production for 2017 includes restoration of production that was disrupted as a result of the Alberta wildfires.

Russia is also expected to be a source of non-OPEC production growth throughout the forecast period, with increases in annual average production projected to be 0.1 million b/d for both 2017 and 2018. Russia's output broke post-Soviet records numerous times in 2016, with liquid fuels production averaging 11.2 million b/d, posting growth of 0.2 million b/d during the year. Despite the forecast for year-over-year liquid supply growth in 2017, Russia's production is expected to decline through much of 2017, at least in part due to its agreement with OPEC to restrain output. Kazakhstan's output is also expected to rise in 2017 and 2018 as a result of the production restart at the giant Kashagan field. Kashagan began commercial production in November, and EIA expects that the field will increase output to 0.3 million b/d by the end of 2017.

Non-OPEC unplanned production outages in December were about 0.3 million b/d, a slight decrease from the November level. During 2016, non-OPEC unplanned supply outages averaged slightly below 0.5 million b/d, roughly 0.1 million b/d higher than the 2015 average. The increase was mainly the result of the wildfire-related outages in Canada during the spring and summer of 2016.

OPEC Petroleum and Other Liquid Fuels Supply. OPEC crude oil production averaged 32.9 million b/d in 2016, an increase of 0.8 million b/d from 2015, led by rising production in Iran, Iraq, and, to a lesser extent, Saudi Arabia. Forecast OPEC crude oil production rises by 0.3 million b/d in 2017, with Iran and Libya accounting for nearly all of the increase. EIA expects that OPEC crude oil output will rise by an additional 0.5 million b/d in 2018, driven by an increase in Iraqi output. The increase in Iraq's production will likely be delayed from 2017 until 2018 as a result of the November 2016 OPEC production target agreement, limiting Iraq's output to roughly 4.4 million b/d starting in January 2017 and lasting for six months. The forecast assumes that OPEC countries subject to the recent production targets will largely adhere to them.

EIA expects crude oil production to increase in countries not covered by the agreement, most notably Libya, where previously shut-in fields continue to see increasing production. EIA also expects Nigeria's production to increase slightly in 2017.

In addition, OPEC's largest producer, Saudi Arabia, could increase crude oil production going into the summer months to satisfy domestic demand for crude oil use for electric power generation, which has been as high as 0.9 million b/d during peak demand months.

OPEC noncrude liquids production averaged 6.7 million b/d in 2016 and is forecast to increase by 0.3 million b/d in 2017 and by 0.2 million b/d in 2018, led by increases in Iran and Qatar.

OPEC unplanned crude oil supply disruptions averaged nearly 1.9 million b/d in December, down slightly from the November level. Outages in Libya decreased in December because of the reopening of the Sharara and El-Feel fields in the western part of the country. The fields had been shut since November 2014 and April 2015, respectively, as Zintani militias and a faction associated with Libya's Petroleum Facilities Guard had closed vital pipelines that transport oil from these fields to oil Libya's western export terminals. This development follows the reopening of Libya's eastern ports in September. Libya's National Oil Company lifted a long-standing force majeure at the Zuetinia and Ras Lanuf ports, which resulted in Libya's crude oil output doubling between September and December. Unplanned outages in Nigeria continue at roughly 0.6 million b/d, as major crude oil streams (Bonny Light, Forcados, Brass River, and Qua Iboe) continue to experience production disruptions.

OPEC surplus crude oil production capacity is expected to be 1.3 million b/d in 2017 and to be 1.2 million b/d in 2018. Surplus capacity is typically an indicator of market conditions, and surplus capacity below 2.5 million b/d indicates a relatively tight oil market. However, high current and forecast levels of global oil inventories make the forecast low surplus capacity less significant.

OECD Petroleum Inventories. EIA estimates that OECD commercial crude oil and other liquid fuels inventories were 3.10 billion barrels at the end of 2016, equivalent to roughly 66 days of consumption. Forecast OECD inventories rise to 3.13 billion barrels at the end of 2017 and to 3.16 billion barrels at the end of 2018.

Crude Oil Prices. The monthly average spot price of Brent crude oil increased by $9/b in December to $53/b. Market reactions to the November 30 OPEC agreement to cut production by 1.2 million b/d starting in January 2017 were a major contributor to rising oil prices in December.

Brent crude oil spot prices are expected to remain fairly flat in the coming months. Despite the recent OPEC agreement, EIA expects global oil inventory builds to continue but at a generally slower rate in 2017 and 2018 than the 2016 average build of 0.9 million b/d. Inventory builds are forecast to average 0.4 million b/d in the first half of 2017 before falling to an average of 0.2 million b/d in the second half of 2017, with a draw expected during the third quarter. The expected persistence of excess global oil supply in the near term, along with the responsiveness of U.S. tight oil production to rising oil prices in late 2016, is expected to limit significant upward oil price pressures in 2017. Brent crude oil prices are forecast to average $53/b in the first half of 2017 and $54/b in the second half of 2017.

Some upward price pressures are expected to emerge in 2018. Global oil markets are expected to be more balanced by mid-2018, with global oil inventories transitioning from moderate builds of 0.4 million b/d in the first half of the year to an average draw of 0.1 million b/d in the second half, resulting in a build of about 0.1 million b/d build for all of 2018. EIA forecasts Brent prices to average $55/b during the first half of 2018 and $57/b in the second half of 2018.

Average West Texas Intermediate (WTI) crude oil prices are forecast to be $1/b lower than Brent prices in 2017 and 2018. The slight price discount of WTI to Brent in the forecast is based on the assumption of competition between the two crude oils in the U.S. Gulf Coast refinery market.

Global economic developments and geopolitical events in the coming months have the potential to push oil prices higher or lower than the current STEO price forecast. Uncertainty remains as to the effectiveness and duration of the concurrent OPEC and non-OPEC production cuts, which could influence prices in either direction. Also, the potential for continued efficiency gains and cost reductions from non-OPEC producers in the new higher price environment could result in additional volumes of supply that could put downward pressure on prices.

The current values of futures and options contracts highlight the heightened volatility and high uncertainty in the oil price outlook. WTI futures contracts for April 2017 delivery that were traded during the five-day period ending January 5 averaged $55/b, and implied volatility averaged 29%. These levels established the lower and upper limits of the 95% confidence interval for the market's expectations of monthly average WTI prices in April 2017 at $43/b and $71/b, respectively. The 95% confidence interval for market expectations widens over time, with lower and upper limits of $35/b and $93/b for prices in December 2017. In January 2016, WTI for April 2016 delivery averaged $38/b, and implied volatility averaged 46%, with the corresponding lower and upper limits of the 95% confidence interval at $25/b and $56/b.

U.S. Liquid Fuels

Consumption. Total U.S. liquid fuels consumption increased by an estimated 60,000 b/d (0.3%) in 2016, as growth in motor gasoline, residual fuel oil, and jet fuel consumption was partially offset by a decline in distillate fuel consumption. Liquid fuels consumption is forecast to increase by 260,000 b/d (1.3%) in 2017 and by an additional 380,000 b/d (1.9%) in 2018.

Hydrocarbon gas liquids (HGL) consumption is expected to be a major contributor to overall U.S. liquid fuels consumption growth in the forecast period. HGL consumption fell by an estimated 30,000 b/d (1.1%) in 2016, but it is projected to increase by 90,000 b/d (3.7%) in 2017 and by 200,000 b/d (7.7%) in 2018.

Most of the forecast growth comes from new ethylene-producing petrochemical plants that will use ethane as their feedstock. Ethane consumption, which averaged an estimated 1.1 million b/d in 2016, is forecast to increase by 110,000 b/d (9.4%) in 2017 and by 180,000 b/d (14.4%) in 2018 as new ethylene producing petrochemical plants require more ethane as feedstock. The first in a series of new ethylene plants is scheduled to come online in the first quarter of 2017, at Ingleside, Texas. By mid-2018, six new plants and one previously de-activated plant, capable of using a combined 420,000 b/d of ethane feedstock, are expected to begin operations. Most of these plants are designed specifically to use ethane without the ability to switch to other feedstocks.

Motor gasoline consumption increased by an estimated 100,000 b/d (1.1%) to 9.28 million b/d in 2016. The increase in gasoline consumption reflects 2.6% growth in highway travel (because of employment growth and lower retail gasoline prices) that is partially offset by increases in vehicle fleet fuel economy. EIA forecasts that gasoline consumption will increase by 40,000 b/d (0.5%) in 2017 and by 90,000 b/d (0.9%) in 2018. In the forecast, gasoline consumption growth is expected to moderate slightly from 2016 levels, as highway travel growth slows to 1.2% and 1.6% in 2017 and 2018, respectively. Lower growth in highway travel reflects forecasts for slower employment growth and rising gasoline prices. If forecast growth in gasoline consumption is realized in 2017, it would surpass the previous record high level of consumption set in 2007.

Jet fuel consumption increased by an estimated 60,000 b/d (3.6%) in 2016. In the forecast, continued growth in passenger and freight activity is offset by fuel efficiency increases, resulting in roughly unchanged jet fuel consumption through 2018.

Consumption of distillate fuel, which includes diesel fuel and heating oil, declined by an estimated 140,000 b/d (3.5%) in 2016. That decline is the result of warmer-than-normal winter temperatures, reduced oil and natural gas drilling (which uses diesel fuel in its operations), and declining coal production, which has reduced diesel use in rail shipments of coal. Stronger expected economic growth, increasing oil and natural gas drilling activity, and an assumption of normal temperatures contribute to forecast distillate fuel consumption growth of 110,000 b/d (2.9%) in 2017 and 70,000 b/d (1.9%) in 2018.

Supply. EIA estimates that total U.S. crude oil production averaged 8.9 million b/d in 2016, a decline of 0.5 million b/d from 2015 levels, with all of the production decline in the Lower 48 onshore. However, based on the latest available monthly data from October and production estimates from November and December, EIA estimates that production began increasing in the fourth quarter of 2016, averaging 8.9 million b/d for the quarter, up from an average of 8.7 million b/d in the third quarter. If confirmed in final data, this would be the first quarterly production increase since the first quarter of 2015. Although most of the fourth-quarter increase came from the federal Gulf of Mexico, EIA estimates that Lower 48 onshore production also increased by almost 60,000 b/d.

EIA forecasts U.S. crude oil production will increase to an average of 9.0 million b/d in 2017 and to 9.3 million b/d in 2018. Production levels in 2017 are 0.2 million b/d higher than in the previous forecast. The upward revision largely reflects assumptions of higher drilling activity, drilling efficiency, and well-level productivity than assumed in previous forecasts. On a quarterly basis, EIA expects U.S. crude oil production to increase from 8.9 million b/d in the fourth quarter of 2016 to 9.4 million b/d in the fourth quarter of 2018. In the third quarters of both 2017 and 2018, crude oil production decreases because EIA assumes some production declines as a result of hurricane-related outages.

EIA expects Lower 48 onshore crude oil production to average 6.8 million b/d in 2017, up slightly from the 2016 level. In 2018, EIA expects Lower 48 production to increase by almost 0.2 million b/d. EIA expects that declines in Lower 48 onshore crude oil production have largely ended, and production will be relatively flat in the first quarter of 2017 compared with the previous quarter, averaging 6.7 million b/d. Lower 48 crude oil production is then expected to increase at an average month-over-month rate of 20,000 b/d from April 2017 through March 2018 before leveling at just under 7.0 million b/d from April 2018 through December 2018. The growth in Lower 48 onshore crude oil production primarily reflects increased oil production in the Permian Basin in Texas and New Mexico.

In previous forecasts, EIA had expected Lower 48 onshore production to generally decline through the end of 2017. The change in the current forecast reflects crude oil prices that have been higher than forecast in recent months, allowing producers to increase active rigs at a faster pace than expected. Additionally, it reflects the incorporation into EIA's models of continuous productivity improvements and lower breakeven costs. However, the forecast remains very sensitive to actual wellhead prices and rapidly changing drilling economics that vary across regions and operators. EIA expects the WTI price, which is used as a proxy for wellhead prices, to average \$52/b in 2017 and \$55/b in 2018. The current price outlook is expected to support onshore drilling and well completions, which are expected to be complemented by continued increases in rig and well productivity along with falling drilling and completion costs.

There is a lag of roughly six months in the relationship between oil price changes and realized production. Thus, the estimated increases in production in the fourth quarter of 2016 are the cumulative result of price increases during the first half of 2016. As U.S. production increases are realized in a global market that is still building inventories, EIA expects those production increases will moderate further price increases, which in turn will limit further production increases through 2017.

Gulf of Mexico production is forecast to average 1.7 million b/d in 2017, an increase of 0.1 million b/d from 2016, and then increase to 1.9 million b/d in 2018. The anticipated expansion of the Tahiti field (in the Gulf of Mexico) and start of production from the Horn Mountain Deep field in 2017 and the Big Foot and Stampede projects in 2018, along with other projects that will begin operations in 2017 and 2018, are expected to contribute to the increase in the Gulf's production.

Crude oil production in Alaska is expected to be unchanged in both 2017 and 2018 at almost 0.5 million b/d.

EIA projects that HGL production at natural gas processing plants will increase by 0.2 million b/d in 2017 and by 0.4 million b/d in 2018. EIA expects higher ethane recovery rates in 2017 and 2018, following planned increases in demand for petrochemical plant feedstock in the United States and abroad. Recently opened terminals, a growing ship fleet, and pipeline expansions allow more U.S. ethane, propane, and butanes to reach international markets, with forecast net HGL exports expected to increase by 0.2 million b/d in 2017 and by 0.1 million b/d in 2018.

Product Prices. EIA expects the retail price of regular gasoline to average $2.31/gal during the first quarter of 2017, 15 cents/gal higher than projected in last month's STEO, primarily as a result of higher crude oil prices and stronger forecast refinery margins. EIA expects that the U.S. monthly average retail price of regular gasoline will increase from $2.31/gal in January 2017 to a high of $2.50/gal in June before falling to $2.21/gal in December. The U.S. regular gasoline retail price, which averaged $2.15/gal in 2016, is forecast to average $2.38/gal in 2017 and $2.41/gal in 2018.

There is significant variation in the regional forecast for retail gasoline prices. Annual average forecast prices for 2017 range from a low of $2.14/gal in the Gulf Coast—Petroleum Administration for Defense District (PADD) 3—to a high of $2.75/gal in the West Coast (PADD 5).

Refinery wholesale gasoline margins (the difference between the wholesale price of gasoline and the price of Brent crude oil) averaged 35 cents/gal in December. This level was lower than the 45 cents/gal average in December 2015, but it was 24 cents/gal higher than the five-year average for December. Higher U.S. gasoline production and inventory levels in 2016 contributed to refinery wholesale gasoline margins averaging 42 cents/gal for the year, which was down 6 cents/gal from 2015 levels. Despite the rising gasoline production and high inventory levels, margins remain above the five-year average as gasoline consumption is estimated to be up 1.1% in 2016 compared with 2015, and total gasoline exports were up 24% through October 2016 compared with the same period in 2015. Refinery wholesale gasoline margins are expected to average 37 cents/gal in 2017 and 33 cents/gal in 2018.

The diesel fuel retail price averaged $2.31/gal in 2016, which was the lowest annual average since 2004. The diesel price is forecast to average $2.73/gal in 2017 and $2.84/gal in 2018, driven higher primarily by higher crude oil prices and growing diesel consumption, which is expected to contribute to higher diesel refinery margins.

Natural Gas

Natural Gas Consumption. Total U.S. natural gas consumption averaged 75.1 billion cubic feet per day (Bcf/d) in 2016. EIA expects natural gas consumption to increase by 0.3 Bcf/d (0.4%) in 2017 and by 1.5 Bcf/d (2.0%) in 2018. In 2017, increases in total natural gas consumption are mainly because of higher residential and commercial consumption based on a forecast of colder winter temperatures. In 2018, the electric power and industrial sectors are the main drivers of consumption growth.

Based on forecasts by the National Oceanic and Atmospheric Administration (NOAA), EIA projects heating degree days (HDD) to be 6.7% higher in 2017 than in 2016, which had a warmer-than-normal winter. EIA expects residential and commercial natural gas consumption to increase by 6.0% and by 5.2%, respectively, in 2017. In 2018, residential and commercial consumption are both projected to be roughly unchanged from 2017 levels.

Forecast natural gas use in the electric power sector, which increased by 4.2% in 2016, falls by 4.4% in 2017 as rising natural gas prices contribute to increasing coal use for electricity generation. Forecast electric power sector consumption of natural gas increases by 2.7% in 2018 as overall electricity generation rises.

Industrial sector consumption of natural gas increased by 1.9% in 2016, and it is forecast to rise by 0.6% in 2017 and by 1.9% in 2018. New fertilizer and chemical projects contribute to industrial sector natural gas consumption growth. A long period of low natural gas prices in the United States has made it economical for companies to upgrade existing ammonia plants and plan for the construction of new nitrogen projects, adding an estimated production capacity of 5.0 million tons per year through 2019.

Natural Gas Production and Trade. EIA estimates that dry natural gas production averaged 72.4 Bcf/d in 2016, a decline of 1.8 Bcf/d (2.4%) from 2015. This decline is the first time annual average natural gas production has fallen since 2005. Production of marketed natural gas fell 1.8% in 2016 from 2015 levels. The higher decline rate for dry natural gas production compared with marketed production reflects higher rates of ethane recovery.

Dry natural gas production is forecast to increase in 2017 and 2018, rising by 1.4 Bcf/d (2.0%) and by 2.8 Bcf/d (3.8%), respectively. The return to increasing production reflects a forecast of higher Henry Hub natural gas spot prices as well as pipeline buildout, particularly in the Marcellus and Utica natural gas producing regions.

Natural gas pipeline exports increased by 1.0 Bcf/d (21.7%) to 5.9 Bcf/d in 2016, largely because of rising exports to Mexico. EIA expects pipeline exports of natural gas to continue rising because of growing demand from Mexico's electric power sector and because of flat natural gas production in Mexico. Gross pipeline exports are expected to increase by 0.1 Bcf/d in 2017 and by 0.4 Bcf/d in 2018.

Liquefied natural gas (LNG) exports increased from almost zero in 2015 to an average of 0.5 Bcf/d in 2016 with the startup of Cheniere's Sabine Pass LNG liquefaction plant in Louisiana, which sent out its first cargo in February 2016. LNG exports are expected to average 1.4 Bcf/d in 2017 as Sabine Pass ramps up capacity in the middle of the year. In 2018, LNG exports are forecast to average 2.6 Bcf/d. The 2018 growth is driven by the expected start of Cove Point LNG in Maryland in December 2017 and new projects at Cameron LNG and Freeport LNG on the Gulf Coast during the second half of 2018.

With expected growth in gross exports, net imports of natural gas decline from 1.7 Bcf/d in 2016 to 0.7 Bcf/d in 2017. The United States is expected to become a net exporter of natural gas for the year in 2018, with net exports averaging 0.6 Bcf/d.

Natural Gas Inventories. Although natural gas inventories reached a record high of 4,047 Bcf during mid-November, draws in recent weeks have been larger than normal, and inventories ended December below the previous five-year average for the first time since the end of April 2015. Based on an assumption of relatively normal temperatures in the first quarter of 2017, EIA forecasts inventories to be 1,745 Bcf at the end of March, which would be 3.3% below the five-year average for that time of year. Inventories are expected to build at a pace that is slower than the five-year average from the end of March through October, bringing inventories to a projected 3,667 Bcf at the end of October, which is 5.0% below the previous five-year average for the end of October. In 2018, inventories are expected to largely follow the typical seasonal pattern.

Natural Gas Prices. The Henry Hub natural gas spot price averaged $2.51/MMBtu in 2016, and it is expected to increase to an average of $3.55/MMBtu in 2017 and then average $3.73/MMBtu in 2018. Prices generally increased throughout 2016 because of high natural gas use for electricity generation during the hot summer and because of declining production. Henry Hub spot prices in December 2016 averaged $3.59/MMBtu, when inventories fell below the five-year average. This was the first time the price averaged more than $3/MMBtu for a month since December 2014.

Higher residential and commercial space heating demand during the first quarter of 2017 compared with a year earlier (which was very warm) is expected to keep prices above $3.50/MMBtu into April. With natural gas production also expected to be lower than year-ago levels in the first quarter of 2017, EIA expects inventory levels to be below the previous five-year average through much of the winter, putting upward pressure on natural gas prices. In 2018, upward price pressures are expected to continue, as both domestic consumption and exports growth are forecast to accelerate.

Natural gas futures contracts for April 2017 delivery that were traded during the five-day period ending January 5 averaged $3.38/MMBtu. Current options and futures prices indicate that market participants place the lower and upper bounds for the 95% confidence interval for April 2017 contracts at $2.39/MMBtu and $4.77/MMBtu, respectively. Last year at this time, the natural gas futures contracts for April 2016 delivery averaged $2.38/MMBtu, and the corresponding lower and upper limits of the 95% confidence interval were $1.61/MMBtu and $3.52/MMBtu, respectively.

Coal

Coal Supply. EIA estimates that coal production declined by 158 million short tons (MMst) (18%) in 2016, to 739 MMst, which would be the lowest level of coal produced since 1978. The decline in coal production in 2016 would be the largest annual decline in terms of both tons and percentage based on data going back to 1949. In 2017, growth in coal-fired electricity generation is expected to lead to an increase of 51 MMst (7%) in total U.S. coal production, with the majority of the increase coming from the Western and Interior regions. Total coal production in 2018 is expected to increase only slightly, with coal production growth in the Western region mostly offset by declines in the Interior region and Appalachia region.

Electric power sector coal stockpiles were 163 MMst in October 2016, a 3% increase from September, which follows the normal seasonal pattern of stockpiles building during the fall months. The end-of-October coal stocks were 12 MMst (7%) lower than the October 2015 level, but nearly identical (163 MMst) to the previous 10-year average for the month. EIA estimates power sector inventories ended 2016 at 170 MMst, which is slightly higher than the 10-year average of 167 MMst.

Coal Consumption. Coal consumption in the electric power sector, which accounts for more than 90% of total U.S. coal consumption, is estimated to have declined by 60 MMst (8%) in 2016. The decline is a result of competition with low-priced natural gas and the relatively mild temperatures in the first half of 2016 that reduced overall electricity demand. Coal consumption in the electric power sector is forecast to increase by 41 MMst (6%) in 2017, mostly because of rising natural gas prices and increasing electricity generation. However, a reverse of these trends in 2018 is expected to lead to an 11 MMst (1%) decline in power sector coal consumption.

Coal Trade. Coal exports in October 2016 were nearly 1 MMst (14%) higher than in the previous month, but exports for the first 10 months of 2016 were 29% (19 MMst) lower than the amount exported over the same period in 2015. EIA estimates U.S. coal exports for all of 2016 declined by 18 MMst (24%) to 56 MMst, the lowest annual level since 2006. Exports are expected to be 54 MMst in 2017 and in 2018.

Atlantic and Gulf Coast power generators are forecast to maintain their current levels of coal imports, which are primarily from Latin America. Imports are estimated to have been 10 MMst in 2016 and forecast to be nearly 11 MMst in both 2017 and 2018.

Coal Prices. EIA estimates the delivered coal price averaged $2.13/MMBtu in 2016, a 4% decline from the 2015 price. Coal prices are forecast to increase in 2017 and in 2018 to $2.18/MMBtu and $2.21/MMBtu, respectively.

Electricity

Electricity Consumption. EIA projects that the average residential customer will consume 3% more electricity between December 2016 and March 2017 compared with the same period last winter. However, this forecast is highly dependent on winter temperatures. Total U.S. consumption of electricity in 2016 was 1.2% lower than in 2015. For all of 2016, EIA estimates residential electricity sales were unchanged from 2015. Forecast residential sales remain flat in 2017 and increase by 0.9% in 2018. Sales of electricity to the commercial sector were relatively unchanged in 2016 and are expected to remain flat in 2017, followed by growth of 0.7% in 2018. Industrial electricity sales declined by 4.3% in 2016 and are expected to rise by 3.0% in 2017 and by 0.5% in 2018.

Electricity Generation. In 2016, annual U.S. electricity generation from natural gas surpassed generation from coal-fired power plants, the first time this has happened based on data going back to 1949. Natural gas supplied an estimated 34% of total U.S. electricity generation in 2016 compared with 30% for coal. Natural gas prices have increased in recent months, with the Henry Hub price rising from an average of $1.73/MMBtu in March 2016 to $3.59/MMBtu in December 2016. These higher prices have begun to encourage more electricity generation from coal-fired power plants, a trend that should continue during 2017. The natural gas share of electricity generation in 2017 is forecast to fall to 32.3%, and the coal share of generation is expected to rise to 32.5%.

EIA forecasts that the share of generation provided by natural gas will rise slightly to 32.8% in 2018, even as natural gas prices are expected to increase slightly between 2017 and 2018. The share of coal generation is expected to average 31.6% in 2018. The share of generation from nuclear falls to 18.8% in 2018, from 19.7% in 2016. Generation from hydropower remains relatively steady, averaging 6.4% of total generation over the next two years. The share of generation from nonhydropower renewables rises from 8.3% in 2016 to 9.1% in 2018 as new wind and solar capacity comes online.

Electricity Retail Prices. The U.S. residential electricity price averaged 12.5 cents per kilowatthour (kWh) in October 2016. This price is 2.1% lower than the U.S. residential price in October 2015. EIA expects the annual average U.S. residential electricity price to increase by 2.6% in 2017 and by 2.5% in 2018.

Renewables and Carbon Dioxide Emissions

Electricity and Heat Generation from Renewables. EIA expects total renewables used in the electric power sector to decrease by 0.3% in 2017 and then increase by 7.3% in 2018. Forecast electricity generation from hydropower falls by 2.2% in 2017 and increases by 4.2% in 2018.

Consumption of renewable energy other than hydropower in the electric power sector is forecast to grow by 1.3% in 2017 and by 9.8% in 2018.

EIA expects that utility-scale solar capacity will grow by about 8.5 gigawatts (GW) in 2017 and 2018 combined. This projected increase would bring the amount of solar capacity at the end of 2018 to 26.5 GW. States leading in utility-scale solar capacity additions are California, Nevada, North Carolina, Texas, and Georgia. Forecast utility-scale solar generation averages 1.2% of total U.S. electricity generation in 2018.

U.S. wind capacity totaled 76.0 GW at the end of 2016, and by 2018 that capacity is expected to rise to 89.2 GW. Forecast wind generation accounts for 6% of total generation in 2018.

Liquid Biofuels. On November 23, 2016, the U.S. Environmental Protection Agency (EPA) finalized a rule setting Renewable Fuel Standard (RFS) volumes for 2017. EIA used the final volumes to develop the current STEO forecast for 2017 but does not assume any explicit RFS targets for the 2018 forecast. EIA expects that the largest effect of the finalized 2017 RFS targets will be on biomass-based diesel consumption, which includes both biodiesel and renewable diesel and helps to meet the RFS targets for use of biomass-based diesel, advanced biofuel, and total renewable fuel. Biodiesel production averaged 99,000 b/d in 2016, and it is forecast to increase to an average of 104,000 b/d in 2017 and 111,000 b/d in 2018. Net imports of biomass-based diesel are expected to rise from 47,000 b/d in 2016 to 51,000 b/d in 2017 and to 57,000 b/d in 2018.

Ethanol production averaged 1.0 million b/d in 2016, and it is forecast to average around 1.0 million b/d in both 2017 and 2018. Ethanol consumption averaged about 940,000 b/d in 2016, and it is forecast to average about 940,000 b/d in 2017 and 950,000 b/d in 2018. This level of consumption results in the ethanol share of the total gasoline pool averaging about 10% in both 2017 and 2018, as only marginal increases in higher-level ethanol blends are assumed to occur during the STEO forecast period.

Energy-Related Carbon Dioxide Emissions. EIA estimates that energy-related emissions of carbon dioxide decreased by 1.6% in 2016. Emissions are forecast to increase by 1.6% in 2017 and by 0.8% in 2018. These forecasts are sensitive to assumptions about weather, economic growth, and fuel prices.

U.S. Economic Assumptions

Recent Economic Indicators. After growing at an annual rate of 3.5% during the third quarter of 2016, real gross domestic product (GDP) growth is projected to increase at an annual rate of 1.8% in the fourth quarter of 2016 and 2.3% in the first quarter of 2017. Inventory investment and net exports, which boosted real GDP growth in the third quarter of 2016, are expected to restrain GDP growth in late 2016 and early 2017. The U.S. economic expansion will become more balanced as 2016 ends, with consumer spending, residential construction, business fixed investment, and government spending all contributing to economic growth.

Production, Income, and Employment. EIA used the December 2016 version of the IHS Markit macroeconomic model with EIA's energy price forecasts as model inputs to develop the economic projections in the STEO.

Forecast real GDP growth is estimated to have been 1.6% in 2016, and it is expected to be 2.3% in 2017 and 2.6% in 2018. Real disposable income grows by 2.8% in 2017 and by 3.9% in 2017. Forecast total industrial production rises by 1.3% in 2017 and by 3.2% in 2017. Projected growth in nonfarm employment averages 1.3% in 2017 and 1.2% in 2017, down from growth of 1.7% in 2016.

Expenditures. Forecast private real fixed investment growth averages 3.9% and 4.1% in 2017 and 2018, respectively. Real consumption expenditures grow faster than real GDP in 2017 and 2018, at 2.8% and 3.0%, respectively. Export growth is 2.3% in 2017 and 2.8% in 2018, and import growth is 4.0 % and 6.0% over the same two years, respectively. Total government expenditures rise by 0.5% in both 2017 and 2018.

Petroleum and Natural Gas Markets Review

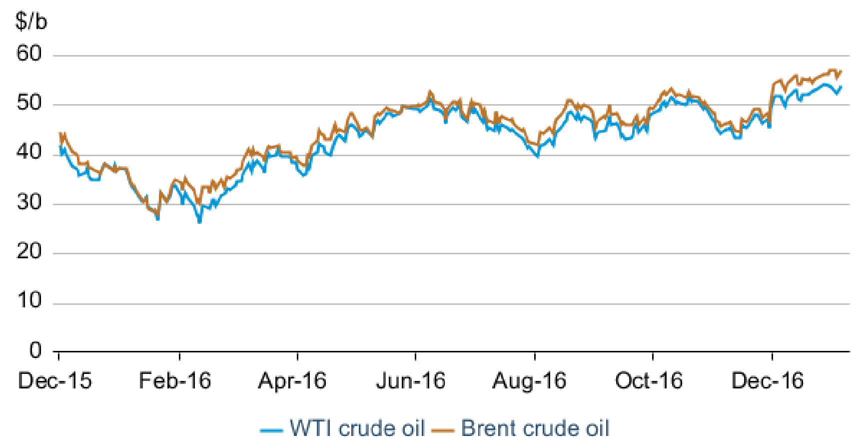
Crude Oil

Prices: Crude oil prices traded above $50 per barrel (b) through most of December, reaching their highest levels since mid-2015. The Brent and West Texas Intermediate (WTI) front-month futures prices closed at $56.89/b and $53.76/b, respectively, on January 5, increases of $2.95/b and $2.70/b, respectively, since December 1 **(Figure 1)**. Brent and WTI average spot prices in December were $8.56/b and $6.26/b higher, respectively, compared with November averages.

On November 30, members of the Organization of the Petroleum Exporting Countries (OPEC) agreed to reduce oil production in the first half of 2017. This agreement was a contributor to rising oil prices in early December. On December 10, 11 non-OPEC countries, including Russia, also agreed to reduce output in early 2017 as part of an effort with OPEC countries to accelerate rebalancing in the oil market.

Some countries within the agreements have confirmed with customers that they will reduce oil deliveries in the coming months, providing more credibility to the stated production targets. These confirmations likely provided additional support for higher oil prices. However, some countries not subject to the terms of the agreement could increase production in the coming months, which is expected to result in an increase in global oil supplies and could delay consistent global inventory withdrawals until the second half of 2018. Uncertainty in the production response from Libya, Nigeria, and the United States in the coming months presents some of the largest risks to the timeline of oil market rebalancing.

Figure 1. Crude oil front-month futures prices



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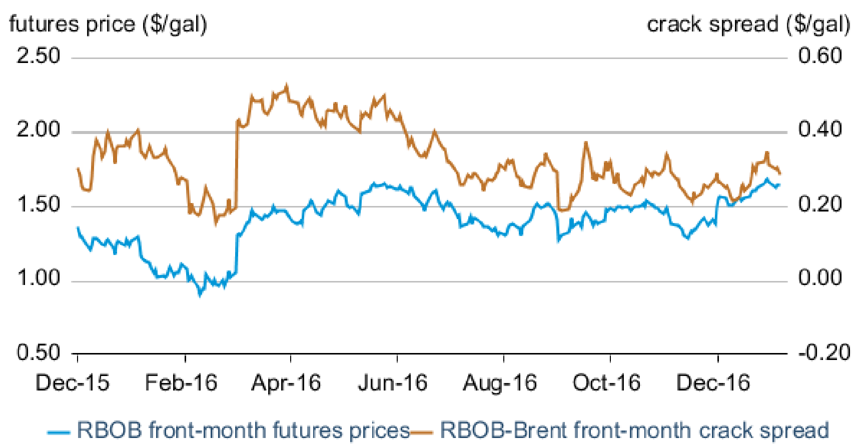
Petroleum Products

Gasoline Prices: The front-month futures price of reformulated blendstock for oxygenate blending (RBOB, the petroleum component of gasoline used in many parts of the country) rose 9 cents per gallon (gal) from December 1 to settle at $1.64/gal on January 5 **(Figure 2)**. The RBOB-Brent crack spread (the difference between the price of RBOB and the price of Brent crude oil) rose 2 cents/gal over the same period.

In late December, the RBOB price reached its highest point since August 2015, supported by strong international demand for gasoline. Initial weekly estimates show that U.S. gasoline exports set a record high in December 2016 of 1.0 million b/d, as refiners on the U.S. Gulf Coast continue to increase gasoline exports to destinations including Mexico and South America.

Figure 2. Historical RBOB futures prices and crack spread



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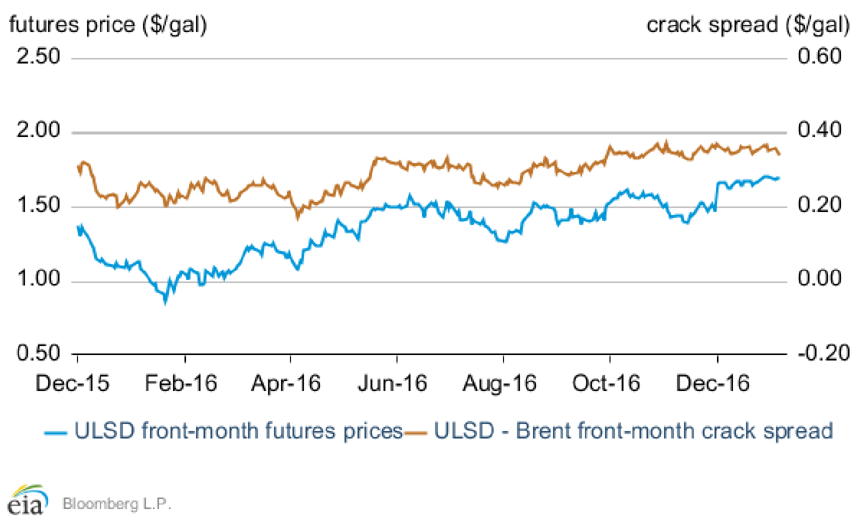
Ultra-low Sulfur Diesel Prices: The front-month futures price for the New York Harbor ultra-low sulfur diesel (ULSD) contract rose 5 cents/gal from December 1 to settle at $1.69/gal on January 5. The ULSD-Brent crack spread was mostly stable over the same period, down 2 cents/gal **(Figure 3)**.

U.S. distillate stocks rose to the top of the five-year range in December. Additionally, distillate stocks in the Petroleum Administration for Defense Districts 1A and 1B, which are regions in the U.S. Northeast that have the highest share of households using distillate for home heating, set a new five-year high. High distillate inventory levels, particularly in areas in the U.S. Northeast, could moderate any impact of cold temperatures on ULSD price movements in the coming weeks.

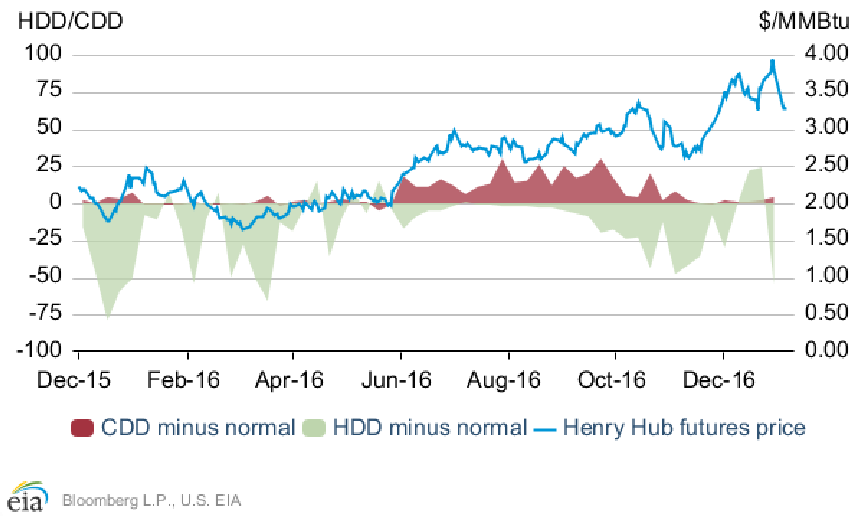
Figure 3. Historical ULSD futures price and crack spread



Natural Gas

Prices and temperatures: The front-month natural gas contract for delivery at Henry Hub declined 23 cents per million British thermal units (MMBtu) from December 1 and settled at $3.27/MMBtu on January 5 **(Figure 4)**. The monthly average natural gas spot price in December increased $1.04/MMBtu from the November average.

Figure 4. Actual minus historical average HDD and CDD



Both natural gas futures and spot prices rose in early December because of forecasts of much colder-than-normal weather for mid-December. However, these factors affected spot prices (which represents the price for very near-term delivery) more than they affected futures prices. U.S. heating degree days (HDD) averaged 23 HDD above normal for the two weeks ending December 22, which contributed to higher natural gas demand and the largest December net inventory withdrawal since 2013, putting upward pressure on prices towards the end of the month. The January futures contract expired on December 28 at the monthly high of $3.93/MMBtu, the highest front-month futures price settlement since December 2014. With the front-month contract moving to February delivery and weather models showing a generally warmer outlook in the eastern part of the country than previously expected, futures prices again declined in the first week of 2017. The wide range in prices in December and early January shows the influence of changing weather forecasts in a market with tightening supply and demand fundamentals.

Notable forecast changes

- For more information, see the detailed table of forecast changes

This report was prepared by the U.S. Energy Information Administration (EIA), the statistical and analytical agency within the U.S. Department of Energy. By law, EIA's data, analyses, and forecasts are independent of approval by any other officer or employee of the United States Government. The views in this report therefore should not be construed as representing those of the U.S. Department of Energy or other federal agencies.