January 2018

Short-Term Energy Outlook (STEO)

Forecast highlights

- This edition of the *Short-Term Energy Outlook* is the first to include forecasts for 2019.

- Benchmark North Sea Brent crude oil spot prices averaged $64 per barrel (b) in December, an almost $2/b increase from the November average and the highest monthly average since November 2014.

- Brent crude oil prices averaged $54/b in 2017 and are forecast to average $60/b in 2018 and $61/b in 2019. West Texas Intermediate (WTI) crude oil spot prices are forecast to average $4/b less than Brent prices in both 2018 and 2019. EIA's forecast for the average WTI price for December 2018 of $58/b should be considered in the context of NYMEX contract values for December 2018 delivery. NYMEX contract values traded during the five-day period ending January 4 suggest that a range of $40/b to $85/b encompasses the market expectation for WTI prices in December 2018 at the 95% confidence level.

- U.S. regular gasoline retail prices averaged $2.48 per gallon (gal) in December, down almost 9 cents/gal from the average in November but 22 cents/gal higher than at the same time last year. U.S. regular gasoline retail prices averaged $2.42/gal in 2017 and are forecast to average $2.57/gal in 2018 and $2.58/gal in 2019.

- U.S. crude oil production averaged an estimated 9.3 million barrels per day (b/d) in 2017 and is estimated to have averaged 9.9 million b/d in December. U.S. crude oil production is forecast to average 10.3 million b/d in 2018, which would mark the highest annual average production in U.S. history, surpassing the previous record of 9.6 million b/d set in 1970. EIA forecasts production to increase to an average of 10.8 million b/d in 2019 and to surpass 11 million b/d in November 2019.

- Dry natural gas production is forecast to average 80.4 billion cubic feet per day (Bcf/d) in 2018, a 6.9 Bcf/d increase from the 2017 level, which would be the highest year-over-year increase on record. Forecast dry natural gas production increases by an average of 2.6 Bcf/d in 2019.

- Henry Hub natural gas spot prices are forecast to average $2.88 per million British thermal units (MMBtu) in 2018 and $2.92/MMBtu in 2019, compared with the 2017 average of $2.99/MMBtu. EIA's forecast for the average Henry Hub price for December 2018 of $3.04/MMBtu should be considered in the context of NYMEX contract values for December 2018 delivery. NYMEX contract values traded during the five-day period ending January 4 suggest that a range of $1.83/MMBtu to $4.89/MMBtu encompasses the market expectation for Henry Hub prices in December 2018 at the 95% confidence level.

- Coal production increased by 45 million short tons (MMst) (6%) in 2017 in response to high demand for U.S. coal exports. Coal production is forecast to decline by 14 MMst (2%) in 2018 and by 18 MMst (2%) in 2019, as export demand is expected to slow and natural gas prices are expected to stay below $3/MMBtu during much of the forecast period, which contributes to less coal use for electricity generation.

- EIA expects the share of U.S. total utility-scale electricity generation from natural gas to rise from 32% in 2017 to 33% in 2018 and to 34% in 2019, as a result of low natural gas prices. Coal's forecast generation share falls from 30% in 2017 to slightly lower than 30% in 2018 and 28% in 2019. The nuclear share of generation was 20% in 2017 and is forecast to average 20% in 2018 and 19% in 2019. Nonhydropower renewables provided almost 10% of electricity generation in 2017, and its 2018 share is expected be similar before increasing to almost 11% in 2019. The generation share of hydropower was more than 7% in 2017 and is forecast to be slightly lower than 7% in both 2018 and 2019.

- After declining by 1.0% in 2017, energy-related carbon dioxide (CO2) emissions are forecast to increase by 1.7% in 2018 and by 0.2% in 2019. Energy-related CO2 emissions are sensitive to changes in weather, economic growth, and energy prices.

Global Liquid Fuels

EIA estimates that global petroleum and other liquid fuels inventory draws averaged 0.4 million barrels per day (b/d) in 2017, marking the first year of global inventory draws since 2013. EIA expects global inventories to increase by 0.2 million b/d in 2018 and by 0.3 million b/d in 2019.

The Brent crude oil spot price averaged $54/b in 2017, an increase of $10/b from 2016 levels. Daily Brent spot prices ended 2017 near $67/b, which was the highest price level since December 2014. The price increase in 2017 is consistent with the global inventory draws experienced during the year. EIA expects that the modest inventory builds forecast for 2018 and 2019 will contribute to Brent crude oil prices declining from current levels to an average of $60/b in the first quarter of 2018. Brent prices are then expected to remain relatively flat near $60/b for the remainder of the forecast period. Forecast Brent spot prices average $60/b in 2018 and $61/b in 2019.

Global Petroleum and Other Liquid Fuels Consumption. Global consumption of petroleum and other liquid fuels grew by 1.4 million b/d in 2017, reaching an average of 98.4 million b/d for the year. Although the rate of consumption growth slowed in 2017 compared with 2016, EIA expects that consumption growth will average 1.7 million b/d in 2018 and almost 1.7 million b/d 2019, driven by the countries outside of the Organization for Economic Cooperation and Development (OECD). Non-OECD consumption growth would account for 1.2 million b/d and 1.3 million b/d of the global growth in 2018 and 2019, respectively. The non-OECD petroleum and other liquid fuels consumption growth is driven by a forecast of higher growth in non-OECD oil-weighted Gross Domestic Product (GDP). Growth in non-OECD oil-weighted GDP is expected to be 4.3% in 2018 and 4.4% in 2019, up from 3.9% in 2017.

EIA expects India and China to be the largest contributors to growth in non-OECD petroleum and other liquid fuels consumption in 2018 and 2019. China's consumption is expected to increase by 0.4 million b/d in 2018, followed by a 0.3 million b/d increase in 2019. Consumption growth in China reflects expectations of increased use of gasoline, jet fuel, and, to a lesser extent, hydrocarbon gas liquids (HGL). India, which saw slower-than-expected liquid fuels consumption growth of less than 0.1 million b/d in 2017, partly because of monetary and fiscal policy changes, is expected to experience stronger growth in 2018 and 2019, with consumption forecast to grow by about 0.3 million b/d in each year.

In addition to growth in China and India, EIA expects petroleum and other liquid fuels consumption growth in the Middle East to rise in 2018 and 2019, with increases of 0.1 million b/d in 2018 and 0.2 million b/d in 2019. Saudi Arabia continues to see increasing domestic petroleum consumption despite the expansion of natural gas use for electric power generation. EIA expects that Saudi Arabia's direct burn of crude oil for electric power generation will remain at roughly the 2017 level throughout the forecast period.

OECD petroleum and other liquid fuels consumption increased by 0.4 million b/d in 2017, and EIA expects it will grow by 0.5 million b/d in 2018 and by 0.3 million b/d in 2019. The main driver of OECD consumption growth is the United States. In Asia and Oceania, declining consumption in Japan in 2018 and 2019 is partially offset by modest growth in other areas. Europe is expected to see modest consumption growth in 2018 followed by a small decline in 2019.

Non-OPEC Petroleum and Other Liquid Fuels Supply. EIA estimates that petroleum and other liquid fuels production increased by 0.7 million b/d in 2017 in countries outside of the Organization of the Petroleum Exporting Countries (OPEC). Combined production growth of 1.0 million b/d in the United States and Canada more than offset a decrease of 0.3 million b/d among the rest of the non-OPEC producers.

EIA expects non-OPEC petroleum and other liquid fuels production to rise by 2.0 million b/d in 2018 and by 1.3 million b/d in 2019. The forecast production growth is centered in the Americas, as U.S. production growth is forecast to average 1.5 million b/d in in 2018 and 1.0 million b/d in 2019. Canada and Brazil are expected to contribute combined growth of 0.4 million b/d in both 2018 and 2019.

Canada's petroleum and other liquid fuels production grows by 0.3 million b/d in 2018 and by 0.2 million b/d in 2019 in EIA's forecast. In Canada, oil sands projects continue to drive production growth during the forecast period, with the new phases of the Horizon oil sands project adding production starting in November 2017. In addition, the Fort Hills project, which is planned to come online in late 2018 is also expected to contribute another 0.2 million b/d to Canada's output in 2019. In addition to production increases from oil sands, the recently-started Hebron offshore field is also expected to add 0.1 million b/d of production in 2019.

Brazil's petroleum and other liquid fuels production is expected to grow by 0.1 million b/d in 2018 and by 0.2 million b/d in 2019, accounting for the third-highest source of non-OPEC production growth after the United States and Canada. Development of pre-salt resources and recent regulatory changes in the Brazilian oil industry are the main drivers of the growth. Continued implementation of reforms, including those to local content rules, could result in higher production growth during the forecast period. The oil-rich Santos Basin, particularly the Lula field, is expected to add enough oil production in the next two years to offset declines in Brazil's more mature onshore and offshore areas. Production at Lula began in November 2017.

Other sources of growth for non-OPEC petroleum and other liquid fuels production in 2018 and 2019 include Kazakhstan, where EIA forecasts production to continue to increase at the Kashagan field.

Norway is expected to post a production increase of 0.1 million b/d in 2018 before production decreases modestly in 2019, as steep crude oil production decline rates offset the expected startup of the Martin Linge and Johan Sverdrup fields, along with a number of smaller fields.

Russia's petroleum and other liquid fuels production is expected to fall by about 0.1 million b/d in 2018 and remain at that level in 2019. Russia's output is expected to decrease from a number of oil fields, which will be partly offset by increases in new field production, including the Erginskoye field in Western Siberia. Erginskoye is expected to begin production in 2019 and to reach peak production of 0.1 million b/d beyond the end of the current forecast period.

Non-OPEC unplanned supply outages in December 2017 were 0.6 million b/d, an increase of 0.3 million b/d compared with the November level. The increase mainly reflected a 0.3 million b/d disruption in the United Kingdom, where the Forties pipeline was shut on December 11. The pipeline closure required fields that rely on the Forties pipeline for takeaway transportation to shut in production. The fields included the Buzzard, United Kingdom's largest oilfield. Ineos, the pipeline's operator, reportedly restarted flows at a reduced rate in late December.

During 2017, non-OPEC unplanned supply outages averaged about 0.5 million b/d, roughly 0.1 million b/d higher than the 2016 average. The increase mainly reflected outages in Canada at the Syncrude Mildred Lake facility during the spring and summer of 2017, along with production shut-ins in the U.S. Gulf of Mexico as a result of hurricanes.

OPEC Petroleum and Other Liquid Fuels Supply. OPEC crude oil production averaged 32.5 million b/d in 2017, a decrease of 0.2 million b/d from 2016. The decline was mainly a result of the November 2016 OPEC production agreement that aimed to limit OPEC crude oil output to 32.5 million b/d. Saudi Arabia and a number of Persian Gulf producers reduced crude oil production in support of the agreement. Other countries saw supplies decline because of political factors, as was the case in Venezuela. OPEC and non-OPEC participants agreed on November 30, 2017, to extend the production cuts through the end of 2018 in an effort to reduce global oil inventories. OPEC crude oil production is forecast to increase by 0.2 million b/d in 2018, partially reflecting EIA's expectation of Libya maintaining relatively high production levels achieved near the end of 2017. EIA expects that OPEC crude oil output will rise by an additional 0.3 million b/d in 2019 as crude oil production slowly returns to pre-agreement levels.

In the fourth quarter of 2017, the average compliance rate among OPEC members was near 100%. However, the high compliance rate in the latest data includes a sizeable drop in Venezuela's production level of more than 0.2 million b/d in 2017. As of December 2017, Venezuela's crude oil production was about 1.8 million b/d, the lowest level since February 2003, when most of Venezuela's oil production was shut in during an oil workers' strike. At the time, political opposition to then-president Hugo Chavez organized the industrial action to force a new presidential election, resulting in the shuttering of all but 0.6 million b/d of crude oil production.

EIA expects Venezuela's production to continue to fall through the forecast period as the financial situation of the state-owned Petróleos de Venezuela (PdVSA) becomes more precarious. According to trade press reporting and tanker tracking data, importing diluent for blending with its heavy oil is becoming increasingly difficult for Venezuela. Financial sanctions are also making it difficult to conduct financial transactions, with a number of banks refusing dealings with PdVSA. As a result, Venezuela's oil exports have decreased significantly over the past six months, further limiting Venezuela's access to much-needed cash.

OPEC noncrude oil liquids production averaged 6.8 million b/d in 2017 and is forecast to increase by 0.1 million b/d in 2018 and by 0.2 million b/d in 2019, led by increases in Iran and Qatar.

OPEC unplanned crude oil supply disruptions averaged 1.1 million b/d in December 2017, slightly less than during November. The decline in outages partly reflected increased production in Nigeria. Nigeria's production has also recovered somewhat in 2017 from frequent attacks targeting the oil infrastructure, and the country's December output was 1.8 million b/d, the highest crude oil production level since February 2016. Libya's outages increased in December, as a result of outages at the Waha and AGOCO operated fields during the month, including the late December sabotage of the pipeline that transports Waha field crude oil to the Es Sider terminal. Overall, Libya's restoration of production has reached almost 1.0 million b/d in crude oil output. However, the recent disruptions may signal a possible risk that production in the coming months could be lower than currently expected.

OPEC surplus crude oil production capacity, which averaged 2.1 million b/d in 2017, is expected to fall to 1.8 million b/d in 2018 and to 1.3 million b/d in 2019. Surplus capacity is typically an indicator of market conditions, and surplus capacity lower than 2.5 million b/d indicates a relatively tight oil market. However, ample global oil inventories make the forecast of low surplus capacity less significant.

OECD Petroleum Inventories. EIA estimates that OECD commercial crude oil and other liquid fuels inventories were 2.91 billion barrels at the end of 2017, equivalent to roughly 62 days of consumption. OECD inventories are forecast to rise to 2.96 billion barrels at the end of 2018 and then to 3.05 billion barrels at the end of 2019.

Crude Oil Prices. Brent crude oil averaged $54/barrel (b) in 2017, an increase of $10/b from 2016 levels. Prices increased fairly steadily through the second half of the year, with year-end prices higher than the annual average. Daily Brent spot prices ended 2017 near $67/b, which was the highest level since December 2014. The monthly average spot price of Brent crude oil increased by $2/b in December to $64/b, marking only the fourth time that monthly Brent crude oil prices averaged more than $60/b in the past 36 months.

Most of the upward price movement in recent months reflects continuing draws in global oil inventory levels. EIA estimates that global petroleum and other liquid fuels inventories fell by an average of 0.4 million b/d in 2017, which was the first year of annual average draws since 2013. In addition, oil prices were supported by OPEC’s November 30, 2017, announcement to extend its crude oil supply reduction agreement through the end of 2018. Also, Brent prices increased in December because of a disruption to the North Sea’s Forties crude oil pipeline system early in the month. The Forties pipeline system is one of the primary distribution networks for Brent crude oil delivery in the North Sea, and its outage curtailed available supply in the near term. Trade press reports indicate the Forties pipeline system restarted operations in late December 2017.

EIA forecasts the Brent crude oil spot price will average $60/b in 2018 and $61/b in 2019. After falling in 2017, EIA expects global oil inventories to rise by 0.2 million b/d in 2018 and by 0.3 million b/d in 2019. EIA forecasts the expectation of inventory builds in 2018 and 2019 will contribute to crude oil prices declining from current levels to an average of $60/b during the first quarter of 2018. Prices are then expected to remain relatively flat through 2019.

Daily and monthly average crude oil prices could vary significantly from annual average forecasts, because 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 regarding the duration of, and adherence to, the current OPEC production cuts, which could influence prices in either direction. Also, the U.S. tight oil sector continues to be dynamic, and quickly evolving trends in this sector could affect both current crude oil prices and expectations for future prices.

Average West Texas Intermediate (WTI) crude oil prices are forecast to be $4/b lower than Brent prices in 2018 and in 2019, falling from the $6/b average price difference seen in the fourth quarter of 2017. The falling price discount of WTI to Brent in the forecast is based on the assumption that current constraints on the capacity to transport crude oil from the Cushing, Oklahoma, storage hub to the U.S. Gulf Coast will gradually lessen.

EIA estimates that the price difference between Brent and WTI reflects the competition of the two crude oils in global export markets. Thus, there are two components of the price difference, the cost of delivering WTI crude oil from its pricing point at Cushing to the U.S. Gulf Coast for export and the additional transportation costs U.S. crude oil exports incur on their way to Asia compared with costs to deliver Brent from the North Sea to Asia.

EIA estimates that, without pipeline constraints, moving crude oil from Cushing to the U.S. Gulf Coast typically costs about $3.50/b. EIA estimates that it costs approximately $0.50/b more to transport WTI from the United States to Asia than it costs to ship Brent from the North Sea to Asia. Although more infrastructure to export crude oil has been built recently, U.S. exporters must still use smaller, less-economic vessels or complex shipping arrangements, which add to costs.

The current values of futures and options contracts suggest uncertainty in the oil price outlook. WTI futures contracts for April 2018 delivery that were traded during the five-day period ending January 4 averaged $61/b, and implied volatility averaged 19%. 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 2018 at $52/b and $71/b, respectively. The 95% confidence interval for market expectations widens slightly over time, with lower and upper limits of $40/b and $85/b for prices in December 2018. In January 2017, the WTI futures price for April 2017 delivery averaged $55/b, and implied volatility averaged 29%, with the corresponding lower and upper limits of the 95% confidence interval at $43/b and $71/b.

U.S. Liquid Fuels

Consumption. Total U.S. petroleum and other liquid fuels consumption is forecast in the STEO to average 20.3 million barrels per day (b/d) in 2018, an increase of 470,000 b/d (2.4%) from the 2017 level. Consumption is forecast to grow by 340,000 b/d (1.7%) in 2019. The growth in both years is led primarily by higher consumption of hydrocarbon gas liquids (HGL) and distillate fuel with modest contributions of growth in motor gasoline and jet fuel.

EIA forecasts HGL consumption growth to be the strongest among the liquid fuels. HGL consumption is expected to increase by 300,000 b/d (11.7%) in 2018 and by 260,000 b/d (9.1%) in 2019, with increased ethane consumption accounting for about three quarters of this growth. Seven (six new and one restarted) ethylene-producing petrochemical plants that use ethane as their feedstock are planned to begin operating in the United States by the end of 2019.

Distillate consumption averaged more than 3.9 million b/d during 2017, an increase of 50,000 b/d from 2016 levels. Distillate fuel consumption growth is forecast to accelerate in 2018, with expected annual average growth of 100,000 b/d (2.5%), resulting in average consumption of more than 4.0 million b/d, followed by growth of 10,000 b/d (0.4%) in 2019. U.S. economic activity and industrial output are projected to grow strongly in both 2018 and 2019, contributing to higher distillate use.

Motor gasoline consumption remained nearly flat from 2016 to 2017 at an average of slightly more than 9.3 million b/d. Motor gasoline consumption is forecast to increase by 30,000 b/d (0.3%) in 2018. If EIA’s projected growth is realized, it would be the highest level of annual average gasoline consumption on record, slightly surpassing the previous record set in 2016. Gasoline consumption growth in 2019 is forecast to accelerate slightly, increasing by 50,000 b/d (0.6%) from 2018 levels. Moderate growth in disposable personal income and declining unemployment rates, tempered by increases in motor gasoline prices, contribute to modest increases in forecast vehicle miles traveled throughout 2019.

Jet fuel consumption increased sharply in 2017, growing by 70,000 b/d compared with 2016, averaging almost 1.7 million b/d. However, year-over-year growth in jet fuel consumption is expected to slow in 2018, with growth of 20,000 b/d (1.4%) in 2018 and less than 10,000 b/d (0.4%) in 2019. Growth in the demand for air travel from rising disposable income is offset somewhat by rising jet fuel prices.

Supply. EIA forecasts total U.S. crude oil production to average 10.3 million b/d in 2018, up 1.0 million b/d from 2017. If achieved, forecast 2018 production would be the highest annual average on record, surpassing the previous record of 9.6 million b/d set in 1970. In 2019, crude oil production is forecast to rise to an average of 10.8 million b/d.

Increased production from tight rock formations within the Permian region in Texas and New Mexico accounts for 0.8 million b/d of the expected 1.2 million b/d of crude oil production growth from December 2017 to December 2019. EIA expects most of the remaining 0.3 million b/d of growth to come from the Federal Gulf of Mexico, as seven new projects are expected to come online by the end of 2019.

The Permian region is expected to produce 3.6 million b/d of crude oil by the end of 2019, which is roughly a 0.9 million b/d increase from estimated December 2017 levels and would represent about 32% of total U.S. crude oil production in 2019. The Permian region is the geographic area that predominately spans the Permian Basin of western Texas and southeastern New Mexico and covers 53 million acres. Within the Permian Basin are smaller sub-basins, including the Midland Basin and the Delaware Basin, all of which contain historically prolific non-tight formations as well as many prolific tight formations such as the Wolfcamp, Spraberry, and Bonespring. With the large geographic area of the Permian region and stacked plays, operators can continue to develop multiple tight oil layers and increase production, even with sustained prices lower than $50/b. Increases in proppant intensity, lateral lengths, changes to slick-water completions, and drilling in sweet spots have driven increased initial production (IP) rates and rig activity in the Permian, allowing it to remain one of the most economic regions for oil production. The Permian region rig count is projected to grow from about 398 at the end of 2017 to 490 at the end of 2019.

Production from the Eagle Ford region is expected to be between 1.2 million b/d and 1.3 million b/d in 2018 and 2019, slightly higher than the 2017 level. Compared with the Permian, the Eagle Ford region has a significantly smaller geographic area (16 million acres), fewer prolific stacked formations, and fewer opportunities to drill. However, similar to the Permian, Eagle Ford wells have high IP rates and fast decline rates, requiring the continuous drilling of new wells to maintain production levels. Historically, rig counts have been very responsive to price changes in the Eagle Ford region. Consequently, they have been declining since May 2017 because of oil prices dropping below $50/b in mid-2017. With EIA's forecast WTI price averaging $55/b in 2018 and $57/b in 2019, Eagle Ford rigs are expected to grow from 80 at the end of 2017 to 95 at the end of 2019.

The Bakken region is expected to produce an average of 1.2 million b/d in 2018 and 1.3 million b/d in 2019, up from 1.1 million b/d in 2017. The Bakken region predominately spans the Williston Basin that contains the Bakken and Three Forks formations. Although the Bakken region is geographically large (23 million acres), it contains fewer identified prolific formations than the Permian region. In addition, operators in this region are affected by winter weather and have greater transportation constraints in moving oil to refineries and markets. Rig counts in this region are expected to grow from 49 at the end of 2017 to 69 at the end of 2019.

Gulf of Mexico production is forecast to average 1.7 million b/d in 2018, which would be relatively unchanged from 2017 levels, and then increase to 1.8 million b/d in 2019. The anticipated start of production in 2019 from the Appomattox project in the Rydberg field and the Mars projects in the Kaikias field, along with other projects that will begin operations in 2018 and 2019, are expected to contribute to increases in production from the Gulf of Mexico.

Crude oil production in Alaska is expected to remain flat at 0.5 million b/d in both 2018 and 2019. Ongoing exploration and developmental drilling in the North Slope and the anticipated start of production from 1H News project in November 2017 and the Greater Moose's Tooth project in 2018 are expected to keep production in Alaska from declining as it has been in recent years.

Growth in crude oil production, especially in the Permian Basin, is expected to result in increased associated natural gas production and natural gas processing. EIA forecasts HGL production at natural gas processing plants will increase by 0.5 million b/d in 2018 and by 0.4 million b/d in 2019. EIA expects higher ethane recovery rates in 2018 and 2019, following planned increases in demand for petrochemical plant feedstock in the United States and abroad.

Product Prices. EIA expects the retail price of regular gasoline to average $2.51 per gallon (gal) during the first quarter of 2018, 19 cents/gal higher than at the same time last year, primarily reflecting higher crude oil prices. EIA expects that the U.S. monthly retail price of regular gasoline will increase from an average of $2.54/gal in January to a 2018 peak of $2.63/gal in August before falling to $2.47/gal in December 2018. The U.S. regular gasoline retail price, which averaged $2.42/gal in 2017, is forecast to average $2.57/gal in 2018 and $2.58 /gal in 2019.

Regional annual average forecast prices for 2018 range from a low of $2.29/gal in the Gulf Coast—Petroleum Administration for Defense District (PADD) 3—to a high of $3.03/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 25 cents/gal in December. This level was lower than the 32 cents/gal average in December 2016, but it was 8 cents/gal higher than the five-year average for December. Refinery wholesale gasoline margins averaged 41 cents/gal in 2017, which was relatively unchanged from the 2016 level but 8 cents/gal higher than the previous five-year average. Refinery wholesale gasoline margins are expected to average 37 cents/gal in 2018 and 34 cents/gal in 2019.

The diesel fuel retail price averaged $2.65/gal in 2017, which was 34 cents/gal higher than the average in 2016. The diesel price is forecast to average $2.95/gal in 2018 and $3.01/gal in 2019, driven higher primarily by higher crude oil prices and growing global diesel demand. Rising diesel consumption is expected to contribute to gradually increasing diesel refinery margins. Diesel refinery margins based on Brent crude oil are expected to average 47 cents/gal in 2018 and 46 cents/gal in 2019, compared with an average of 40 cents/gal in 2017.

Natural Gas

Natural Gas Consumption. Total U.S. natural gas consumption averaged 74.0 billion cubic feet per day (Bcf/d) in 2017, a 1% decrease from 2016. Natural gas consumption is forecast to increase by 3.5 Bcf/d in 2018 and by 2.2 Bcf/d in 2019. The 2017 decrease in total natural gas consumption mainly reflects warm winter temperatures and lower electric power sector use. In 2017, U.S. heating degree days (HDD) were 2% lower than in 2016, and U.S. cooling degree days (CDD) in 2017 were 8% lower than in 2016. Electric power sector use of natural gas decreased by 1.6 Bcf/d (6%) in 2017. The decline reflects competition from increasing renewable energy use (particularly hydropower), competitive coal prices, and overall lower electricity generation levels.

Based on forecasts by the National Oceanic and Atmospheric Administration (NOAA), EIA projects 2018 HDD will be 11% higher than 2017 levels. The difference is driven temperatures during first quarters of 2017 and 2018. The first quarter of 2017 was unseasonably warm, and the first quarter of 2018 is projected to be relatively close to the 10-year average. On an annual basis, EIA expects combined residential and commercial natural gas consumption to increase by 1.3 Bcf/d in 2018 compared with 2017 levels and remain mostly unchanged in 2019.

Industrial sector consumption of natural gas increased by 1.6% from 2016 to 2017. In 2018, industrial consumption is expected to rise by 1.2%, averaging 21.7 Bcf/d in 2018. Industrial consumption is expected to increase by 2.6% in 2019. Most of the increase in the 2019 forecast is attributable to new chemical plants expected to come online. A low natural gas price environment in recent years has made it economical to increase the use of natural gas as feedstock in ammonia for nitrogenous fertilizer and methanol.

Natural Gas Production and Trade. Dry natural gas production averaged 73.6 Bcf/d in 2017, up 1.0% from the 2016 level and reversing the 2016 production decline. The strongest growth in dry natural gas production occurred late in the year, as improved economics related to expanded pipeline capacity contributed to a 3.8% increase in production between the third and fourth quarters of 2017. The rate of production growth is expected to moderate in 2018.

EIA expects dry natural gas production to rise by 6.9 Bcf/d (9.3%) in 2018 and by 2.6 Bcf/d (3.2%) in 2019. If achieved, the forecast 6.9 Bcf/d increase in 2018 would be the highest on record. Growth is expected to be concentrated in Appalachia's Marcellus and Utica regions, along with the Permian Basin region. Much of the expected increase in natural gas production is the result of increasing pipeline takeaway capacity out of the Appalachia producing region to end-use markets. The greater pipeline connectivity contributes to higher wellhead natural gas prices for producers and is expected to encourage production growth.

EIA projects liquefied natural gas (LNG) gross exports will average 3.0 Bcf/d in 2018, up from 1.9 Bcf/d in 2017. In 2018, U.S. liquefaction capacity will continue to expand. EIA expects the Cove Point terminal in Maryland to ramp up to full capacity. At the Elba Island facility in Georgia, 6 of the 10 small modular trains, each with a capacity of 0.03 Bcf/d, are expected to enter service. The first liquefaction train (capacity 0.7 Bcf/d) at Freeport LNG in Texas is also expected to come online by the end of 2018. EIA projects gross LNG exports to average 4.8 Bcf/d in 2019, when the four remaining modular trains at Elba Island come online and the remaining two trains at Freeport LNG enter service. Two trains in Corpus Christi, Texas, and three trains at Cameron LNG in Louisiana are also expected to enter service in 2019. EIA forecasts exports will ramp up in the second half of 2019 to an average of 5.5 Bcf/d, up from 4.1 Bcf/d in the first half of 2019. In both 2018 and 2019 the new liquefaction facilities will require a ramp up period, and they are forecast to operate below nameplate capacity for a period of time, lowering the overall LNG export capacity utilization rate.

Natural gas pipeline exports to Mexico through October increased by 0.4 Bcf/d in 2017 compared with the same period in 2016, and EIA expects growth to continue over the forecast period with ongoing Mexican energy market reform. A relatively low natural gas export price, rising demand from Mexico's power sector, and increased pipeline capacity in both in the United States and Mexico have led to increased exports. U.S. gross pipeline exports are expected to increase by 0.6 Bcf/d in 2018 and by 0.8 Bcf/d in 2019 to an average of 8.0 Bcf/d.

Total U.S. natural gas imports averaged 8.2 Bcf/d in 2017, and they are expected to average 7.9 Bcf/d in 2018 and 8.2 Bcf/d in 2019. A low natural gas price environment in Western Canada could contribute to increased seasonal imports for some regional U.S. markets.

In 2017, the United States was a net exporter of natural gas for the first time on an annual basis since 1957,[1] with net exports averaging 0.4 Bcf/d. Overall, net natural gas exports are forecast to average 2.3 Bcf/d in 2018 and 4.6 Bcf/d in 2019.

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[1] This sentence was updated on January 11, 2018, to add "since 1957." It was originally published on January 9, 2018, as: "In 2017, the United States was a net exporter of natural gas for the first time on an annual basis, with net exports averaging 0.4 Bcf/d"

Natural Gas Inventories. As of December 29, 2017, working natural gas inventories were 3,126 Bcf, 6% lower than both the five-year average and year-ago levels. Inventory draws in recent weeks have been larger than normal for this time of year, despite a rare winter injection of 2 Bcf during the week ending December 2, the first December injection since 2012. Based on an assumption of relatively normal temperatures in the first quarter of 2018, along with a forecast of growing natural production, EIA forecasts inventories to be 1,623 Bcf at the end of March, which would be 6% lower than the five-year average for that time of year. Inventories are expected to build slightly above the five-year average pace from the end of March through October, bringing inventories to a projected 3,861 Bcf at the end of October 2018, which is slightly higher than the previous five-year average for the end of October. In 2019, inventories are expected to be about 6% lower on average than 2018 levels.

Natural Gas Prices. Henry Hub spot prices averaged $2.99 per million British thermal units (MMBtu) in 2017, up 47 cents/MMBtu from a 17-year low in 2016. Henry Hub natural gas spot prices are forecast to average $2.88/MMBtu in 2018 and $2.92/MMBtu in 2019. Prices are expected to decline slightly from 2017 levels based on strong expected production growth, which EIA forecasts will meet growing domestic consumption and exports.

Natural gas futures contracts for April 2018 delivery that were traded during the five-day period ending January 4 averaged $2.75/MMBtu. Current options and futures prices indicate that market participants place the lower and upper bounds for the 95% confidence interval for April 2018 contracts at $2.01/MMBtu and $3.75/MMBtu, respectively. Last year at this time, the natural gas futures contracts for April 2017 delivery averaged $3.38/MMBtu, and the corresponding lower and upper limits of the 95% confidence interval were $2.39/MMBtu and $4.77/MMBtu, respectively.

Coal

Coal Supply. EIA estimates that coal production increased by 45 million short tons (MMst) (6%) in 2017 to 773 MMst, as demand for U.S. coal exports increased. In 2018, total U.S. coal production is expected to decrease by 14 MMst (2%). Production in the Western region is forecast to decrease by 5 MMst, and production in the Appalachia region is forecast to decrease by 25 MMst. The expected production decline in the Appalachia region and the Western region is primarily a result of the projected declines in coals exports. Declines in these regions are expected to be partially offset by a 15 MMst increase in Interior region production. In 2019, total coal production is expected to decline by 18 MMst (2%), and declines in Appalachian region production and Western region production again partially offset by increases in Interior region production.

Coal Consumption. Coal consumption in the electric power sector is estimated to have declined by 12 MMst (2%) in 2017, as several coal power plants retired. Consumption in the electric power sector is forecast to decrease by 10 MMst (1%) in 2018 and by 27 MMst (4%) in 2019. The decrease in power sector consumption reflects lower natural gas prices and coal power plant retirements.

Coal Trade. Coal exports through the first 10 months of 2017 were 70% higher than in the same period last year, and the 78 MMst exported through October is 18 MMst (29%) more than coal exports for all of 2016. EIA estimates total coal exports for 2017 were 95 MMst, with steam coal exports at 41 MMst. EIA expects that metallurgical coal exports will be more than 50 MMst in both 2018 and 2019, but steam exports will decline by 34% in 2018 and by 15% in 2019. Total coal exports are expected to be 80 MMst in 2018 and 75 MMst in 2019.

Atlantic and Gulf Coast electric power generators are forecast to generally maintain their current levels of coal imports, which are primarily from Latin America. Total U.S. imports are estimated to have been 8 MMst in 2017 and are forecast to be 9 MMst in both 2018 and 2019.

Coal Prices. EIA estimates the delivered coal price averaged $2.10 per million British thermal units (MMBtu) in 2017, which was 1 cent/MMBtu lower than the 2016 price. Coal prices are forecast to increase to $2.21/MMBtu in 2018 and to remain at that level in 2019.

Electricity

Electricity Consumption. EIA expects annual retail sales of electricity to the residential sector in 2018 to be 2.9% higher than sales in 2017 primarily as a result of increased electricity consumption in the first quarter of 2018. Forecast annual electricity sales to the commercial sector are up 0.6% this year from the 2017 level. Industrial sector electricity sales are expected to grow by 0.4% in 2018. Forecast total U.S. consumption of electricity grows by 1.3% in 2018 and by 0.5% in 2019.

The weather last winter was mild throughout much of the United States. According to the National Oceanic and Atmospheric Administration (NOAA), total U.S. heating degree days (HDD) in the winter of 2016–17 were the third lowest on record. NOAA forecasts U.S. HDD for the winter of 2017–18 will be about 10% higher than last winter, but still 2% lower than the average of the previous 10 winters.

Expected colder winter temperatures, especially in the Midwest and Eastern states, drive EIA's forecast that the average U.S. residential customer will consume 4% more electricity this winter compared with the same period last year. Forecast average residential electricity sales between October 2017 and March 2018 range from 3,700 kilowatthours (kWh) per customer in the New England census division (4% higher than last winter) to 7,000 kWh per customer in the East South Central census division (8% higher).

Electricity Generation. The amount of electricity generation from natural gas-fired power plants fell between 2016 and 2017, however natural gas remained the primary fuel for power generation for the second year in a row. Natural gas supplied an estimated 32% of total U.S. electricity generation in 2017, down from a share of 34% in 2016, in response to higher prices for the fuel. The U.S. average price for natural gas delivered to electric generators was $3.33/million British thermal units (MMBtu) in 2017, up 16% from the average price in 2016.

As reported on the EIA-860M survey, power plant operators are scheduled to bring 20 gigawatts (GW) of new natural-gas fired generating capacity online in 2018. This addition would be the largest increase in natural gas capacity since 2004. Most of this new capacity uses combined-cycle technology, which can be efficiently run for long periods of operation. Almost 6 GW of the capacity additions are being built in Pennsylvania, and more than 2 GW are being built in Texas.

EIA expects the price of natural gas for electricity generation in 2018 will be slightly lower than in 2017. The share of total generation produced by natural gas-fired power plants increases to 33% in 2018 as a result of new additions of natural gas generating capacity and an expected reduction in hydroelectric generation. Forecast natural gas prices for electric generators falls to $3.26 in 2019, contributing to EIA's forecast that natural gas will fuel 34% of total generation next year.

In the Western states, EIA expects increased generation from natural gas to partially offset an expected reduction in hydroelectric generation during 2018. Last year, natural gas and hydropower each supplied between 26% and 27% of total generation in the West census region. The share provided by hydropower in the Western states is forecast to fall to 23% in 2018, and the share provided by natural gas is forecast to rise to 29%.

Coal supplied about 30% of total U.S. electricity generation in 2016 and 2017. EIA expects U.S. electricity generation from coal-fired power plants will fall to slightly below 30% in 2018. Power plant operators have reported on the EIA-860M survey that they plan to retire 13 GW of coal-fired capacity in 2018, primarily in the latter half of the year. EIA expects that these retirements and the forecast lower natural gas prices will reduce coal's share of total U.S. generation to 28% in 2019.

EIA expects utility-scale generation from renewable energy sources other than hydropower to continue growing in 2018, albeit at a slower pace than in 2017. Nonhydro renewable energy sources, which supplied an annual average of 9.6% of total U.S. electricity generation in 2017, are forecast to supply more than 10% of annual average total U.S. generation in 2019 for the first time on record.

Nuclear generation contributed 20% of total generation in 2017 and is expected to supply a similar share this year. The scheduled retirement of reactors next year at the Three Mile Island and Pilgrim Nuclear power plants before the end of 2019 contribute to EIA's forecast that the generation share from nuclear will fall to 19% in 2019.

Electricity Retail Prices. The U.S. retail electricity price for the residential sector averaged 12.8 cents/kWh in October 2017 (the latest historical data available), which was 3% higher than the average price in October 2016. EIA expects annual average residential electricity prices will increase by a further 2% in 2018 and 3% in 2019.

Renewables and Carbon Dioxide Emissions

Electricity Renewables Generation and Capacity. After increasing by 13% in 2017, EIA expects total generation from renewables in all sectors (including utility- and small-scale generators) to decrease by 3% in 2018 and then to increase by 7% in 2019. Forecast electricity generation from hydropower decreases by 12% in 2018 and increases by 2% in 2019. This change in hydropower generation drives the decrease in overall renewable generation growth in 2018. Generation from renewable energy other than hydropower in the electric power sector is forecast to grow by 3% in 2018 and by 9% in 2019.

EIA estimates that total U.S. small-scale solar capacity was 16 gigawatts (GW) at the end of 2017. EIA expects that capacity to be 19 GW at the end of 2018 and 23 GW at the end of 2019.

EIA estimates that U.S. large-scale solar capacity totaled 27 GW at the end of 2017 and forecasts by the end of 2018 that capacity will rise to 30 GW. States leading in large-scale solar capacity additions are California, Florida, North Carolina, and Texas. Forecast large-scale solar generation averages 1.5% of total U.S. electricity generation in 2018. By the end of 2019, large-scale solar capacity is forecast to be 42 GW. In 2019 the average generation share is about 1.7% of total generation.

EIA estimates that U.S. large-scale wind capacity totaled 88 GW at the end of 2017, and by the end of 2018 that capacity is expected to rise to 96 GW. Forecast wind generation accounts for 6.4% of total generation in 2018. Wind capacity rises to 104 GW in 2019, and its generation share is 6.9%. If the forecast levels of both wind and hydro generation are met in 2019, it would be the first time that wind generation surpasses hydropower as the leading source of renewable electricity generation.

Liquid Biofuels. In November 2017, the U.S. Environmental Protection Agency (EPA) finalized a rule setting Renewable Fuel Standard (RFS) volumes for 2018 and biomass-based diesel volumes for 2019. EIA used these final volumes to develop the current STEO forecast for 2018 and 2019. EIA expects that the largest effect of the current RFS targets, along with recent duties placed on biodiesel imports, will be on biomass-based diesel production and net imports, which help to meet the RFS targets for use of biomass-based diesel, advanced biofuel, and total renewable fuel. Biodiesel production averaged an estimated 105,000 barrels per day (b/d) in 2017, and it is forecast to increase to an average of 117,000 b/d in 2018 and to 128,000 b/d in 2019. In large part because of recent duties imposed on foreign biodiesel imports from Argentina and Indonesia, net imports of biomass-based diesel are expected to fall from an estimated 41,000 b/d in 2017 to 32,000 b/d in 2018 and then rise to 35,000 b/d in 2019.

Ethanol production averaged an estimated 1.0 million b/d in 2017 and is forecast to average roughly the same in both 2018 and 2019. Ethanol consumption averaged about 940,000 b/d in 2017 and is forecast to be 960,000 b/d in 2018 and 970,000 b/d in 2019. This level of consumption results in the ethanol share of the total gasoline pool increasing from an average of 10.2% in 2017 to an average of 10.3% in 2018 and 2019. This increase in the ethanol share assumes that recent marginal growth in higher-level ethanol blends continue during the forecast period.

Energy-Related Carbon Dioxide Emissions. EIA estimates that energy-related emissions of carbon dioxide decreased by 1.0% in 2017 and forecasts these levels to increase by 1.7% in 2018 and by 0.2% in 2019. These forecasts are sensitive to assumptions about weather, economic growth, and fuel prices.

U.S. Economic Assumptions

Recent Economic Indicators. Real gross domestic product (GDP) increased at an annual rate of 3.1% in the second quarter of 2017 and 3.2% in the third quarter of 2017, according to recent estimates released by the Bureau of Economic Analysis. The acceleration in real GDP in the third quarter reflected an acceleration in private inventory investment, a downturn in imports, and smaller decreases in state and local government spending and in residential fixed investment that were partly offset by decelerations in personal consumption expenditures, in nonresidential fixed investment, and in exports.

Production, Income, and Employment. EIA used the December 2017 version of the IHS Markit macroeconomic model with EIA's energy price forecasts as model inputs to develop the economic forecasts in the STEO.

Real GDP is forecast to increase by 2.4% in both 2018 and 2019 compared with the 2.3% increase in 2017. Real disposable income is forecast to grow by 2.4% in 2018 and by 3.3% in 2019 compared with a 1.3% increase in 2017. Total industrial production is forecast to increase by 3.1% in 2018 and by 2.7% in 2018, compared with a 1.9% increase in 2017. Forecast growth in nonfarm employment averages 1.4% in 2018 and 1.2% in 2019, compared with growth of 1.5% in 2017.

Expenditures. Private real fixed investment is forecast to grow by 3.4% in 2018 and by 4.4% in 2019, compared with 3.9% growth in 2017. Real consumption expenditures are forecast to grow by 2.4% in 2018 and by 2.2% in 2019, compared with a 2.7% increase in 2017.

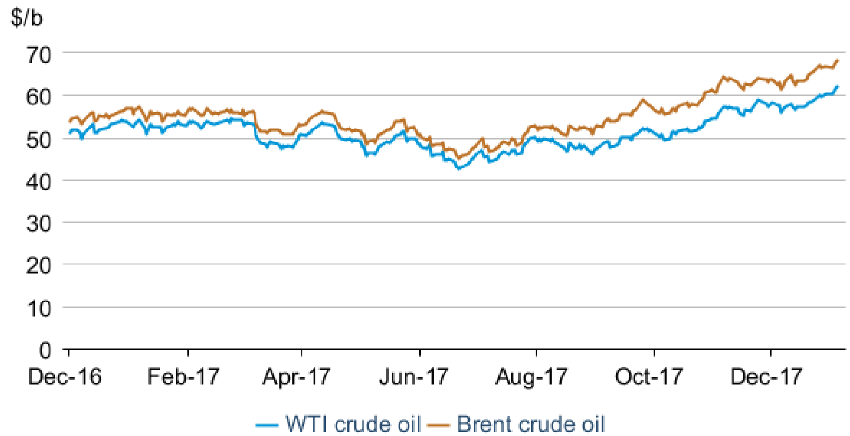
Exports are forecast to grow by 4.3% in 2018 and by 4.2% in 2019, compared with 3.1% growth in 2017. Imports are forecast to grow by 3.6% in 2018 and by 3.3% in 2019, compared with 3.4% growth in 2017. Total government expenditures are forecast to increase by 0.4% in 2018 and by 0.5% in 2019, compared with a 0.1% decline in 2017.

Petroleum and natural gas markets review

Crude oil

Prices: The front-month futures price for North Sea Brent crude oil settled at $68.07 per barrel (b) on January 4, an increase of $4.34/b since December 1. Front-month futures prices for West Texas Intermediate (WTI) crude oil for delivery at Cushing, Oklahoma, increased $3.65/b during the same period, settling at $62.01/b on January 4 **(Figure 1)**. December Brent and WTI monthly average spot prices were $1.66/b and $1.24/b higher than the November average spot prices.

Figure 1. Crude oil front-month futures prices



CME Group and Intercontinental Exchange, as compiled by Bloomberg L.P.

Crude oil prices reached the highest levels in more than three years during the first week in January. The rise in Brent crude oil futures prices likely reflected global oil inventory draws that were estimated to be 0.3 million barrels per day (b/d) during the fourth quarter of 2017. Prices were likely also supported by the shutdown of the Forties Pipeline in the North Sea on December 11 because of a crack in the pipeline, which remained closed through December 30. A brief pipeline outage in Libya may have also affected waterborne crude oil supplies and contributed upward price pressure.

With respect to crude oil demand, U.S. crude oil refinery inputs reached a record high for the month of December during the week ending December 29, 2017, of 17.6 million b/d. Global economic growth and leading economic indicators of manufacturing activity continue to show expansion, which could also support crude oil and petroleum product demand in the coming months.

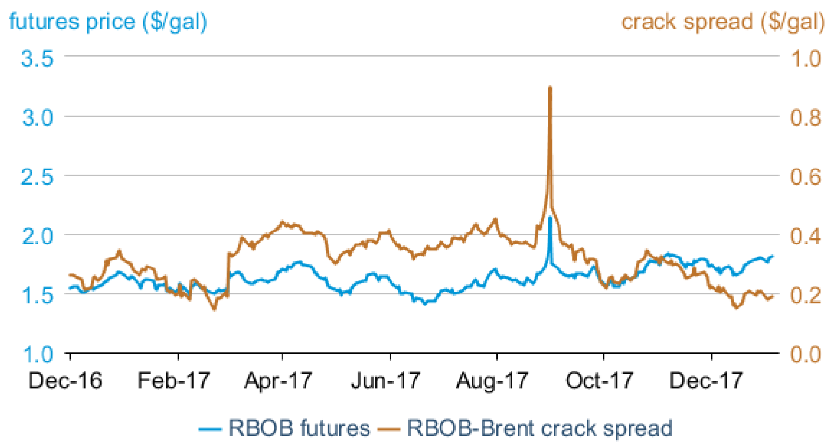
Petroleum products

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 by 7 cents per gallon (gal) from December 1 to settle at $1.81/gal on January 4 **(Figure 2)**. The RBOB–Brent crack spread (the difference between the price of RBOB and the price of Brent crude oil) fell by 4 cents/gal to settle at 19 cents/gal over the same period. EIA compares RBOB prices to Brent prices because EIA research indicates that U.S. gasoline prices usually move with Brent prices, the international crude oil benchmark.

Total motor gasoline stocks generally rise towards the end of the year, as gasoline consumption begins to decline to its seasonal low. In 2017, total motor gasoline stocks rose by 12.3 million barrels from December 1 to December 29, more than double than in 2016, if confirmed by the

Petroleum Supply Monthly (PSM). STEO estimates U.S. gasoline consumption in December 2017 was 0.32 million barrels per (b/d) lower than in the previous year. Finished gasoline exports as of the four weeks ending December 29, 2017, are estimated to be 0.1 million b/d lower than the record high export level set in December 2016, according to the PSM.

Figure 2. Historical RBOB front-month futures prices and crack spread

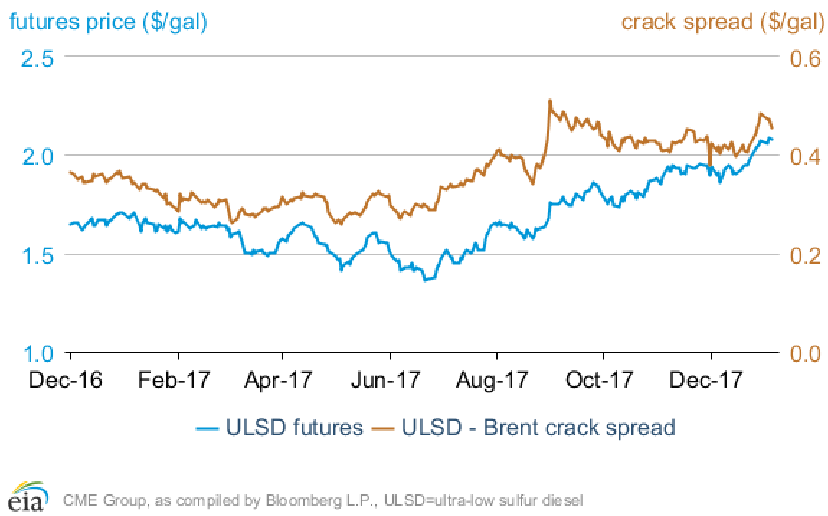


eia CME Group, as compiled by Bloomberg L.P., RBOB=reformulated blendstock for oxygenate blending

Ultra-low sulfur diesel prices: The ultra-low sulfur diesel (ULSD) front-month futures price rose by 14 cents/gal from December 1 to settle at $2.08/gal on January 4. On January 3, the ULSD price reached the highest point since February 2015. The ULSD–Brent crack spread (the difference between the price of ULSD and the price of Brent crude oil) increased 3 cents/gal over the same period, settling at 46 cent/gal **(Figure 3)**.

Distillate prices rose as colder-than-normal temperatures settled in much of the United States, including in the U.S. East Coast—Petroleum Administration for Defense District (PADD) 1—where distillate fuel is used for heating. Distillate stocks remained low in December, with some regional variations. Total U.S. distillate stocks as of December 29, 2017, were below the five-year average for December, when compared with the monthly data in the PSM. However, distillate stocks in the U.S. Central Atlantic (PADD 1B), which includes the New York Harbor delivery point of the ULSD futures contract, were at the five-year average, while distillate stocks in the U.S. Midwest (PADD 2) set a new five-year low.

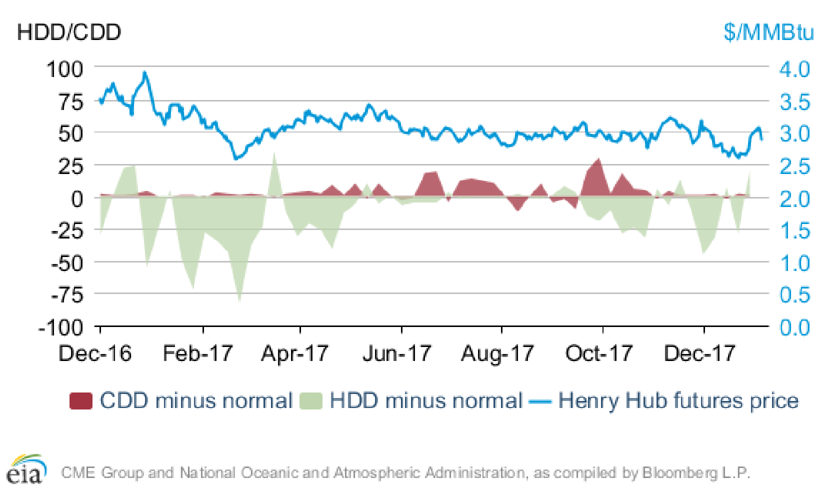
Figure 3. Historical ULSD front-month futures price and crack spread



Natural Gas

The front-month natural gas futures contract for delivery at Henry Hub settled at $2.88/million British thermal units (MMBtu) on January 4, a decrease of 18 cents/MMBtu from December 1 **(Figure 4)**. U.S. dry natural gas production continued to reach record levels, with year-over-year increases estimated at nearly 7 billion cubic feet per day (Bcf/d) in December. The rising production, along with temperatures that averaged 9% warmer than normal for the first three weeks of December, contributed to front-month futures prices on December 21 falling to the lowest level since February 2017. Much colder-than-normal temperatures at the end of December and the beginning of January resulted in estimates of record-high natural gas demand and helped to reverse the price decline. The Henry Hub natural gas spot price averaged $2.81/MMBtu in December, 20 cents/MMBtu lower than November.

Figure 4. Natural gas front month futures prices and actual minus historical average HDD and CDD



Notable forecast changes

- This edition of the *Short-Term Energy Outlook* is the first to include forecasts for 2019.
- For more information, see the detailed table of forecast changes

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