Independent Statistics & Analysis
U.S. Energy Information Administration

April 2018

Short-Term Energy Outlook (STEO)

Forecast highlights

Global liquid fuels

- For the 2018 April–September summer driving season, EIA forecasts U.S. regular gasoline retail prices to average $2.74/gallon (gal), up from an average of $2.41/gal last summer (see Summer Fuels Outlook). The higher forecast gasoline prices are primarily the result of higher forecast crude oil prices. For all of 2018, EIA expects U.S. regular gasoline retail prices to average $2.64/gal and gasoline retail prices for all grades to average $2.76/gal, which would result in the average U.S. household spending about $190 (9%) more on motor fuel in 2018 compared with 2017.

- Brent crude oil spot prices averaged $66 per barrel (b) in March. EIA forecasts Brent spot prices will average about $63/b in both 2018 and 2019. EIA expects West Texas Intermediate (WTI) crude oil prices to average $4/b lower than Brent prices in both 2018 and 2019. NYMEX WTI futures and options contract values for July 2018 delivery that traded during the five-day period ending April 5, 2018, suggest a range of $52/b to $78/b encompasses the market expectation for July 2018 WTI prices at the 95% confidence level.

- EIA estimates that U.S. crude oil production averaged 10.4 million barrels per day (b/d) in March, up 260,000 b/d from the February level. Total U.S. crude oil production averaged 9.3 million b/d in 2017. EIA projects that U.S. crude oil production will average 10.7 million b/d in 2018, which would mark the highest annual average U.S. crude oil production level, surpassing the previous record of 9.6 million b/d set in 1970. EIA forecasts that 2019 crude oil production will again increase, averaging 11.4 million b/d.

Natural gas

- U.S. dry natural gas production averaged 73.6 billion cubic feet per day (Bcf/d) in 2017. EIA forecasts dry natural gas production will average 81.1 Bcf/d in 2018, establishing a new record. EIA expects natural gas production will rise by 1.7 Bcf/d in 2019.

- Growing U.S. natural gas production is expected to support both growing domestic consumption and increasing natural gas exports in the forecast. EIA forecasts U.S. consumption of natural gas to increase by 4.2 Bcf/d (5.7%) in 2018 and by 0.7 Bcf/d (0.9%) in 2019, with electric power generation the leading contributor to this increase.

EIA also expects net natural gas exports to increase from 0.4 Bcf/d in 2017 to an annual average of 2.2 Bcf/d in 2018 and 4.4 Bcf/d in 2019.

- EIA estimates that natural gas inventories ended March (typically considered the end of the winter heating season) at almost 1.4 trillion cubic feet (Tcf), which was 19% lower than the previous five-year average. Based on a forecast of rising production, EIA forecasts that natural gas inventories will increase by more than the five-year average rate of growth during the injection season (April–October) to reach almost 3.8 Tcf on October 31, which would be 2% lower than the previous five-year average.

- EIA expects Henry Hub natural gas spot prices to average $2.99/million British Thermal units (MMBtu) in 2018 and $3.07/MMBtu in 2019. The average NYMEX futures and options contract values for July 2018 delivery that traded during the five-day period ending April 5, 2018, suggest that a range of $2.30/MMBtu to $3.43/MMBtu encompasses the market expectation for July Henry Hub natural gas prices at the 95% confidence level.

Electricity, coal, renewables, and emissions

- For the summer cooling season (June–August), EIA forecasts that the average U.S. household will spend $426 on electricity bills, which would be an increase of more than 3% from last summer. EIA forecasts average household electricity use will be 1% higher this summer compared with last summer, based on a forecast of slightly warmer temperatures, and that retail electricity prices will be 2% higher than last summer.

- EIA expects the share of U.S. total utility-scale electricity generation from natural gas-fired power plants to rise from 32% in 2017 to 34% in 2018 and to remain at 34% in 2019. The forecast electricity generation share from coal averages 29% in both 2018 and 2019, down from 30% in 2017. The nuclear share of generation was 20% in 2017 and is forecast to average 20% in 2018 and 19% in 2019. Nonhydropower renewables provided slightly less than 10% of electricity generation in 2017 and are expected to provide 10% in 2018 and nearly 11% in 2019. The generation share of hydropower was about 7% in 2017 and is forecast to fall to less than 7% in both 2018 and 2019.

- EIA forecasts coal production to decline by 5% to 738 million short tons (MMst) in 2018. The production decrease is largely attributable to lower forecasts of coal use in the electric power sector (down 4% in 2018). Lower expected global demand for U.S. coal exports in 2018 and 2019 also contributes to the forecast of lower coal production. EIA expects production to then increase slightly to 748 MMst in 2019.

- In 2017 EIA estimates that wind generated an average of 697,000 megawatthours per day (MWh/d). EIA projects that will rise to 735,000 MWh/d in 2018 and to 779,000 MWh/d in 2019. If factors such as precipitation and snowpack remain as forecast, conventional hydropower is projected to generate 732,000 MWh/d in 2019, making it the first year that wind generation would exceed hydropower generation in the United States.

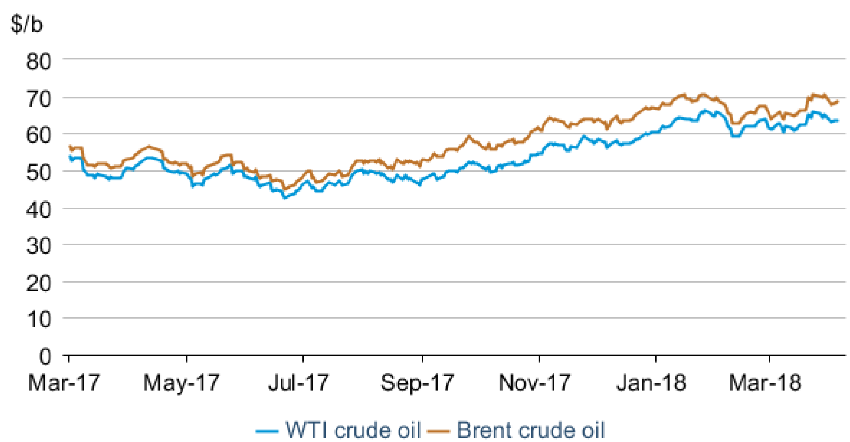
- After declining by 0.7% in 2017, EIA forecasts that energy-related carbon dioxide (CO2) emissions will increase by 0.9% in 2018 and by another 1.0% in 2019. Energy-related CO2 emissions are sensitive to changes in weather, economic growth, and energy prices.

Petroleum and natural gas markets review

Crude oil

Prices: The front-month futures price for North Sea Brent crude oil settled at $68.33 per barrel (b) on April 5, an increase of $4.50/b from March 1, 2018. Front-month futures prices for West Texas Intermediate (WTI) crude oil for delivery at Cushing, Oklahoma, increased by $2.55/b during the same period, settling at $63.54/b on April 5 **(Figure 1)**. March Brent and WTI monthly average spot prices were 70 cents/b and 49 cents/b higher, respectively, than the February average spot prices.

Figure 1. Crude oil front-month futures prices



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

Continuing draws in U.S. and global oil inventories as well as actual and potential supply disruptions may have put upward pressure on crude oil prices in March. Economic and political instability in Venezuela continues to affect its crude oil production. EIA estimates Venezuelan crude oil production averaged 1.5 million barrels per day (b/d) in March, a decline of about 24% year-over-year. In addition, whether or not the United States will extend the Joint Comprehensive Plan of Action (JCPOA) remains uncertain. Without an extension, it could lead to the reinstitution of sanctions on Iran, which could affect Iran's oil production and exports.

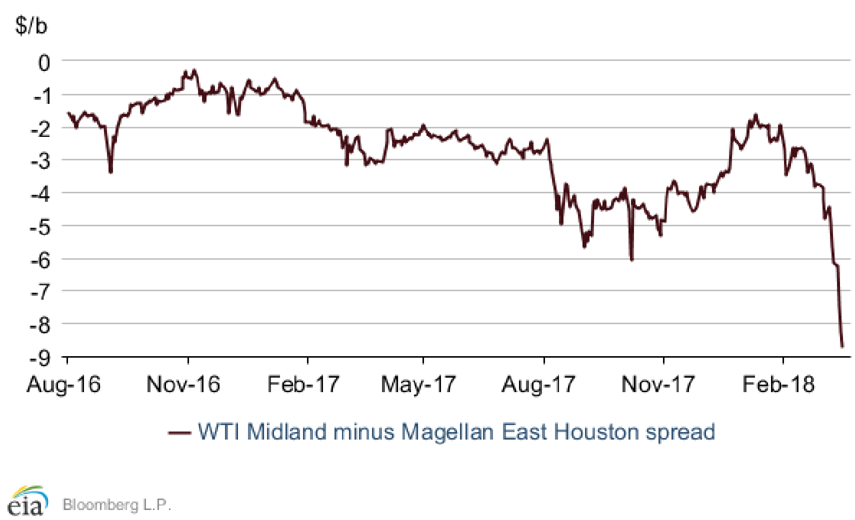
Commercial crude oil inventories in the United States fell lower than the previous five-year average for the week ending March 16, 2018, the first time inventories were lower than the five-year average since 2014. Large inventory declines in the United States during the past year contributed to the 267 million barrel decline in total petroleum inventories since January 2017 in countries in the Organization for Economic Cooperation and Development (OECD), which are estimated to be 2.8 billion barrels as of the end of March.

Despite these supply developments, demand-side factors could have tempered some of the upward oil price pressures in recent weeks. Both the United States and China announced potential tariffs on several billion dollars' worth of each other's goods in March. A slowdown in global trade could affect oil demand and presents downside risks to the global oil consumption forecast, although the forecast was revised higher from EIA's previous STEO. EIA forecasts that global oil consumption will grow by 1.8 million b/d in both 2018 and 2019.

Crude oil price spreads: Crude oil production in the Permian region of Texas and New Mexico could be facing pipeline constraints, which is reflected in a widening discount of WTI Midland crude oil prices to Magellan East Houston crude oil prices. The WTI Midland price discount settled at -$8.70/b on April 5, the largest discount since price postings for Magellan East Houston began in 2016 **(Figure 2)**.

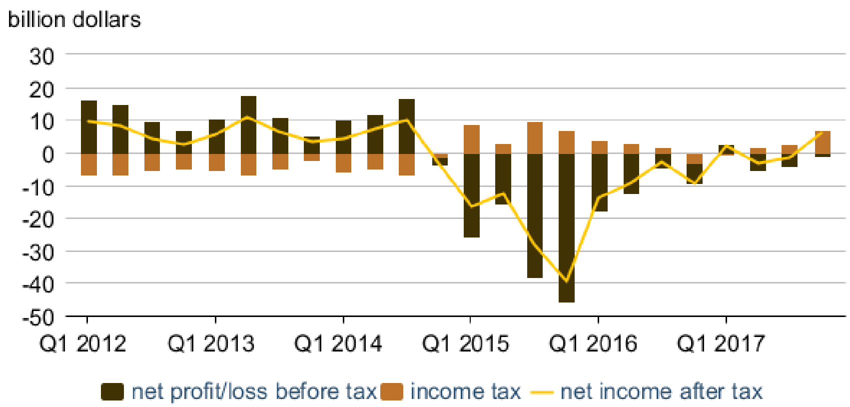
According to EIA's March *Drilling Productivity Report* (DPR), crude oil production growth in the Permian region is forecast to accelerate in March and April, growing month-over-month by 0.07 million b/d and 0.08 million b/d, respectively. The latest pipeline out of the region to begin service is the 0.4 million b/d Midland-to-Sealy pipeline, which began service in the fourth quarter of 2017 and is starting full operations this month. However, the widening price spreads suggest that takeaway constraints could already be affecting oil producers. New pipelines and pipeline expansions are not expected to be completed until the middle of 2019, which could lead to further price volatility for Midland crude oil.

Figure 2. WTI Midland minus Magellan East Houston



Fourth-quarter 2017 financials: Quarterly financial results for 46 U.S. oil exploration and production companies reveal significant effects from the changes to corporate income tax law enacted at the end of 2017. These producers collectively claimed $7 billion in tax benefits in the quarter, contributing to an annual effective tax rate of -147%, which was likely because of a one-time revaluation of the estimates of their future tax liabilities at the lower corporate rate **(Figure 3)**. In addition to the lower corporate income tax rate, U.S. companies are also allowed to accelerate the depreciation of capital investments made through 2023. These two factors could contribute to an increase in investment in upstream production.

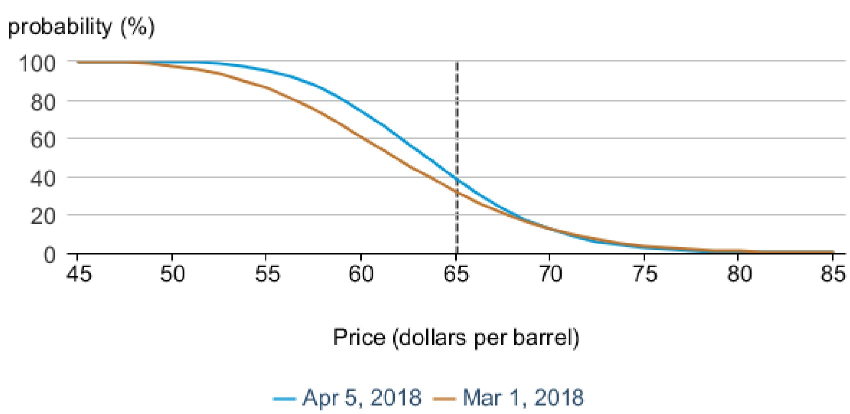
Figure 3. Net profit/loss and income tax for 46 publicly traded U.S. oil companies



U.S. Energy Information Administration, based on Evaluate Energy

Market-derived probabilities: The June 2018 WTI contract averaged $63.64/b for the five trading days ending April 5 and has a market-derived probability of exceeding $65/b of 38% **(Figure 4)**. This contract had a 32% market-derived probability of exceeding $65/b as of March 1. Implied volatility decreased slightly since March 1, but the increase in WTI prices contributed to increasing the probability of exceeding $65/b.

Figure 4. Probability of the June 2018 WTI contract expiring above price levels



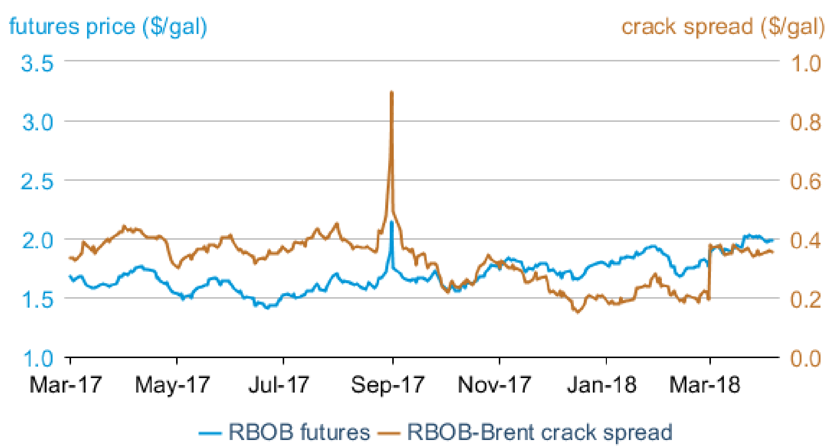
U.S. Energy Information Administration, CME Group

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) at New York Harbor settled at $1.98 per gallon (gal) on April 5, 2018, **(Figure 5),** an increase of 9 cents/gal since March 1, 2018. The RBOB–Brent crack spread (the difference between the price of RBOB and the price of Brent crude oil) decreased by 2 cents/gal to settle at 35 cents/gal over the same period.

EIA estimates that U.S. gasoline consumption (measured as product supplied) was just under 9 million b/d for the first quarter of 2018, which would be the third highest on record for this time of year. Additionally, EIA estimates gasoline consumption plus gasoline exports for the four weeks ending March 30 averaged 10.2 million b/d, which would be an all-time high for the month if confirmed in monthly data.

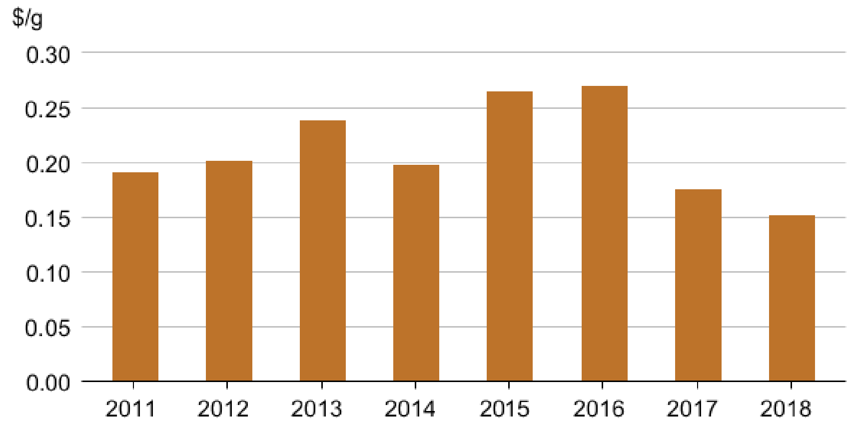
Figure 5. Historical RBOB front-month futures prices and crack spread



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

The RBOB–Brent crack spread typically increases from February to March, as the more expensive April RBOB contract for delivery of summer grade gasoline begins trading in March. Although the RBOB–Brent crack spread increased from February to March this year, the increase was 15 cents/gal, lower than the previous five-year average increase of 23 cents/gal **(Figure 6)**. Despite the strength in first-quarter 2018 gasoline consumption, EIA forecasts second-quarter gasoline consumption to be slightly less than in the same quarter of 2017 at about 9.5 million b/d. In addition, despite the high level of consumption and exports, motor gasoline production has also been higher than year-ago levels, keeping gasoline inventories higher than the five-year average level. EIA estimates that total gasoline inventories ended March at almost 238 million barrels, about 6 million barrels more than the previous five-year average for the end of March.

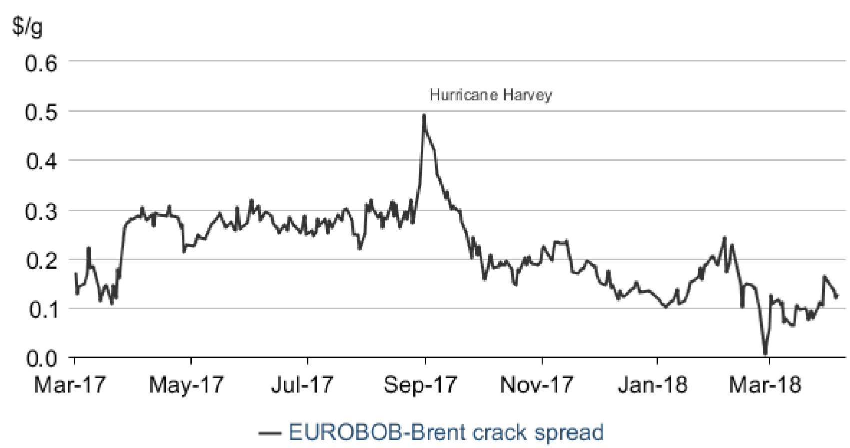
Figure 6. March RBOB-Brent crack spread minus February RBOB-Brent crack spread



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

Another factor that could have contributed to a lower-than-average increase in gasoline crack spreads this year is low gasoline crack spreads in the European gasoline market. The EUROBOB–Brent crack spread averaged 9 cents/gal in March, which is lower than the previous five-year average crack spread of 17 cents/gal **(Figure 7)**. Gasoline inventories at the ARA (Amsterdam, Rotterdam, and Antwerp) hub have been more than the five-year maximum level for the entire month of March after being near the five-year average level in January. About 40% of gasoline imports to the U.S. East Coast come from Europe, so high inventories and low crack spreads in Europe can also affect U.S. gasoline crack spreads.

Figure 7. EUROBOB-Brent crack spread

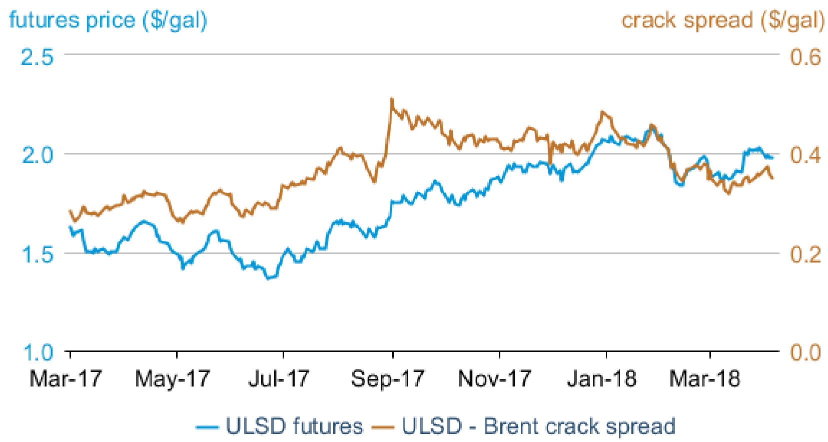


CME Group, as compiled by Bloomberg L.P.

Ultra-low sulfur diesel prices: The ultra-low sulfur diesel (ULSD) front-month futures price increased 9 cents/gal from March 1 to settle at $1.98/gal on April 5. The ULSD–Brent crack spread (the difference between the price of ULSD and the price of Brent crude oil) decreased by 2 cents/gal over the same period, settling at 35 cents/gal **(Figure 8)**.

A brief cold spell in March may have contributed to distillate consumption for the month surpassing 4 million b/d for the second consecutive year. Population-weighted heating degree days in the Middle Atlantic region were 7% higher than the 10-year average. In addition, for the first time since 2011, year-over-year U.S. industrial production growth in March exceeded 3.5% for the third consecutive month. Total U.S. distillate inventories stand 3% lower than the five-year average for the week ending March 30.

Figure 8. Historical ULSD front-month futures price and crack spread

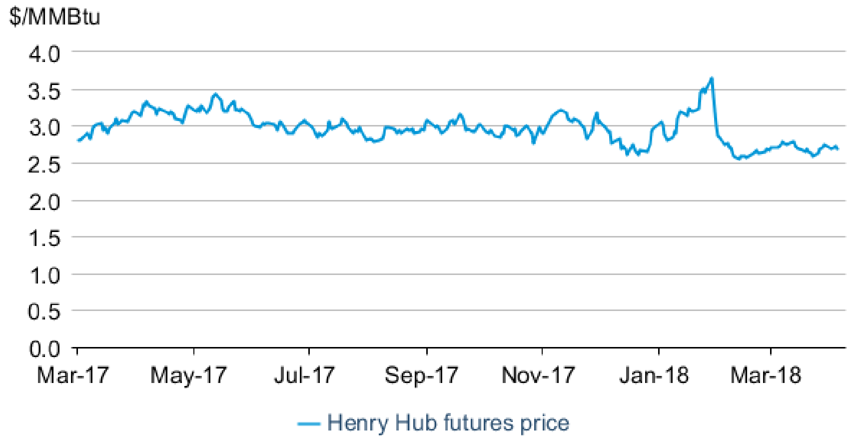


eia CME Group, as compiled by Bloomberg L.P., ULSD=ultra-low sulfur diesel

Natural Gas

The front-month natural gas futures contract for delivery at Henry Hub settled at $2.68/million British thermal units (MMBtu) on April 5, a decrease of 2 cents/MMBtu from March 1 **(Figure 9)**. Record production nearly offset rising exports and above-average consumption to help keep prices in a narrow range in March. Natural gas futures prices traded within a 25 cents/MMBtu range in March, the narrowest range for that month since at least 1995. Estimated U.S. natural gas production in March rose to 79.2 billion cubic feet per day (Bcf/d), 8.4 Bcf/d higher than the previous five-year average. U.S. consumption plus exports increased to 9.0 Bcf/d higher than the previous five-year average. The Henry Hub natural gas spot price averaged $2.69/MMBtu in March, 3 cents/MMBtu higher than in February.

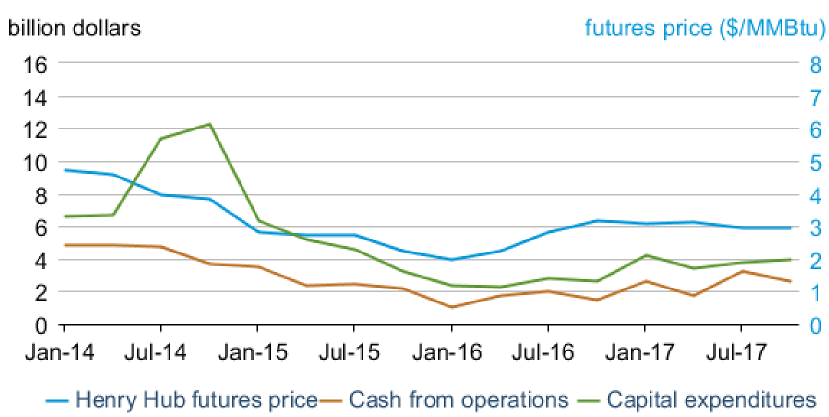
Figure 9. Historical front-month U.S. natural gas prices



CME Group, as compiled by Bloomberg L.P.

Capital expenditures for 20 U.S. natural gas producers rose to $4 billion in the fourth quarter of 2017 **(Figure 10)**, a $1.4 billion increase from the prior year and the second highest quarterly expenditure in two years. Higher revenues and lower costs helped this group of companies report a positive net income in 2017 after two years of losses. Higher net income increased cash from operations and capital expenditures, which contributed to steadily rising natural gas production throughout 2017. Although capital expenditures have exceeded cash from operations since at least 2013 for these companies, the difference narrowed in 2016 and 2017, reducing the need for other types of financing such as issuing debt or equity. Cost declines and productivity increases since 2014 have allowed companies to do more with lower expenditures. Accordingly, U.S. dry natural gas production rose by 3.0 Bcf/d in the fourth quarter of 2017, the largest quarter-over-quarter increase since 1991.

Figure 10. Cash from operations and capital expenditures for 20 U.S. natural gas producers



U.S. Energy Information Administration, Evaluate Energy, CME Group, as compiled by Bloomberg L.P.

Notable forecast changes

- EIA forecasts that natural gas production in the Federal Gulf of Mexico will average 2.6 billion cubic feet per day (Bcf/d) in 2018 and 2.5 Bcf/d in 2019. These forecasts are 0.7 Bcf/d and 0.8 Bcf/d lower, respectively, than in the March STEO. The lower expected production levels are the result of EIA's reassessment of production given historical decline rates in the Federal Gulf of Mexico.

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