Forecast highlights

Global liquid fuels

- Brent crude oil spot prices averaged $63 per barrel (b) in November, up $3/b from October. EIA forecasts Brent spot prices will average $61/b in 2020, down from a 2019 average of $64/b. EIA forecasts that West Texas Intermediate (WTI) prices will average $5.50/b less than Brent prices in 2020. EIA expects crude oil prices will be lower on average in 2020 than in 2019 because of forecast rising global oil inventories, particularly in the first half of next year.

- On December 6, the Organization of the Petroleum Exporting Countries (OPEC) and a group of other oil producers announced they were deepening production cuts originally announced in December 2018. The group is now targeting production that is 1.7 million barrels per day (b/d) lower than in October 2018, compared with the former target reduction of 1.2 million b/d. OPEC announced that the cuts would be in effect through the end of March 2020. However, EIA assumes that OPEC will limit production through all of 2020, amid a forecast of rising oil inventories. EIA forecasts OPEC crude oil production will average 29.3 million b/d in 2020, down by 0.5 million b/d from 2019.

- Beginning on January 1, 2020, the International Maritime Organization (IMO) is set to enact Annex VI of the International Convention for the Prevention of Pollution from Ships (MARPOL Convention), which lowers the maximum sulfur content of marine fuel oil used in ocean-going vessels from 3.5% of weight to 0.5%. EIA expects that starting in the fourth quarter of 2019, this regulation will encourage global refiners to increase refinery runs and maximize upgrading of high-sulfur heavy fuel oil into low-sulfur distillate fuel to create compliant bunker fuels. EIA forecasts that U.S. refinery runs will rise by 3% from 2019 to a record level of 17.5 million b/d in 2020, resulting in refinery utilization rates that average 93% in 2020. EIA expects one of the most significant effects of the regulation to be on diesel wholesale margins, which rise from an average of 45 cents per gallon (gal) in 2019 to a forecasted peak of 61 cents/gal in the first quarter of 2020 and an average of 57 cents/gal in 2020.

- EIA data show that the United States exported 90,000 b/d more total crude oil and petroleum products in September than it imported. This is the first month recorded in U.S. data that the United States exported more crude oil and petroleum products
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than it imported. U.S. imports and exports records of crude oil and petroleum products started on an annual basis in 1949 and on a monthly basis in 1973. EIA expects total crude oil and petroleum net exports to average 570,000 b/d in 2020 compared with average net imports of 490,000 b/d in 2019.

- EIA expects U.S. crude oil production to average 13.2 million b/d in 2020, an increase of 0.9 million b/d from the 2019 level. Expected 2020 growth is slower than 2018 growth of 1.6 million b/d and 2019 growth of 1.3 million b/d. Slowing crude oil production growth results from a decline in drilling rigs over the past year that EIA expects to continue into 2020. Despite the decline in rigs, EIA forecasts production will continue to grow as rig efficiency and well-level productivity rises, offsetting the decline in the number of rigs.

- EIA estimates that propane inventories in the Midwest—Petroleum Administration for Defense District (PADD) 2—were 22.0 million barrels at the end of November, 17% lower than the five-year (2014–18) average for the end of November. Colder-than-normal temperatures and strong grain drying demand in November contributed to large draws on Midwest propane inventories. Also, Western Canadian rail shipments of propane to the Midwest have declined since the opening of a new propane export terminal in Western Canada in May. EIA forecasts Midwest inventories at the end of March will be 32% lower than the five-year (2015–19) average and the lowest for that time of year since 2014.

**Natural gas**

- EIA estimates that the U.S. total working gas inventories were 3,616 billion cubic feet (Bcf) at the end of November. This level was about equal to the five-year (2014–18) average and 19% higher than a year ago. EIA expects storage withdrawals to total 1.9 trillion cubic feet (Tcf) from the end of October to the end of March, which is less than the five-year average winter withdrawal. A withdrawal of this amount would leave the end-of-March inventories at almost 1.9 Tcf, which would be 8% higher than the five-year (2015–19) average.

- The U.S. benchmark Henry Hub natural gas spot price averaged $2.64 per million British thermal units (MMBtu) in November, up 31 cents/MMBtu from October. Prices increased as a result of November temperatures that were colder than the 10-year (2009–18) average. EIA forecasts the Henry Hub spot price to average $2.45/MMBtu in 2020, down 14 cents/MMBtu from the 2019 average.

- EIA forecasts that annual U.S. dry natural gas production will average 92.1 billion cubic feet per day (Bcf/d) in 2019, up 10% from 2018. EIA expects that natural gas production will grow much less in 2020 because of the lag between changes in price and changes in future drilling activity. Low prices in the third quarter of 2019 will reduce natural gas-directed drilling in the first half of 2020. EIA forecasts natural gas production in 2020 will average 95.1 Bcf/d.
Electricity, coal, renewables, and emissions

- EIA expects the share of U.S. total utility-scale electricity generation from natural gas-fired power plants will rise from 34% in 2018 to 37% in 2019 and to 39% in 2020. EIA forecasts the share of U.S. electric generation from coal to average 25% in 2019 and 22% in 2020, down from 28% in 2018. EIA’s forecast nuclear share of U.S. generation remains at about 20% in 2019 and in 2020. Hydropower averages a 7% share of total U.S. generation in the forecast for 2019 and 2020, similar to 2018. Wind, solar, and other nonhydropower renewables provided 9% of U.S. total utility-scale generation in 2018. EIA expects they will provide 10% in 2019 and 12% in 2020.

- EIA expects U.S. coal production in 2019 to total 697 million short tons (MMst), which would be an 8% decline from the 2018 level. In 2020, EIA expects a further decrease in total U.S. coal production of 14%, to an annual total of 601 MMst, reflecting continued idling and closures of mines as a result of declining domestic demand.

- EIA expects U.S. coal exports to total 93 MMst in 2019, and then decline by 8 MMst to 85 MMst in 2020. U.S. coking coal currently faces challenges from a global oversupply of steel, particularly in the fourth quarter of 2019. Steam coal exports have been dampened by high stockpiles in Europe and India, a top destination for U.S. shipments.

- EIA expects U.S. electric power sector generation from renewables other than hydropower—principally wind and solar—to grow from 411 billion kilowatthours (kWh) in 2019 to 471 billion kWh in 2020. In EIA’s forecast, Texas accounts for 20% of the U.S. nonhydropower renewables generation in 2019 and 22% in 2020. California’s forecast share of nonhydropower renewables generation falls from 15% in 2019 to 14% in 2020. EIA expects that the Midwest and Central power regions will see shares in the 16% to 18% range for 2019 and 2020.

- EIA forecasts that, after rising by 2.9% in 2018, U.S. energy-related carbon dioxide (CO2) emissions will decline by 1.4% in 2019 and by 2.2% in 2020, partly as a result of lower forecast energy consumption. For 2019, EIA estimates there was less demand for space cooling because of cooler summer months, with an estimated 5% decline in U.S. cooling degree days from 2018, when temperatures were significantly higher than the previous 10-year (2008–17) average. In addition, EIA also expects U.S. CO2 emissions in 2019 to decline because the forecast share of electricity generated from natural gas and renewables will increase, and the share generated from coal, which is a more carbon-intensive energy source, will decrease.
Petroleum and natural gas markets review

Crude oil

**Prices:** The front-month futures price for Brent crude oil settled at $63.39 per barrel (b) on December 5, 2019, an increase of $1.70/b from November 1. The front-month futures price for West Texas Intermediate (WTI) crude oil for delivery at Cushing, Oklahoma, increased by $2.23/b during the same period, settling at $58.43/b on December 5 (Figure 1).

The increase in crude oil prices over the past month likely reflected modest upward pressures from both demand-side factors and supply-side factors. On the demand side, economic data from the world’s two largest economies—the United States and China—reduced market perceptions of an upcoming slowdown in economic activity. The U.S. Bureau of Economic Analysis released its second estimate of third-quarter 2019 gross domestic product (GDP). This estimate indicated that real U.S. GDP increased at an annual rate of 2.1% in the third quarter, a faster rate than previously estimated and an increase from growth of 2.0% in the second quarter. For China, the Caixin/Markit manufacturing purchasing managers’ index (PMI) for November was 51.8, up from 51.7 in October and the highest level since 2016. Any reading higher than 50 indicates an expected expansion in manufacturing activity.

Concurrently, the S&P 500 equity index closed at a record 3,153.6 on November 27—the day the U.S. GDP estimate was released—an increase of 2.8% from the beginning of the month. The S&P 500 subsequently declined in late November and early December as trade tensions between the United States and China were back in news headlines. Overall, the S&P 500 index was up 2.4% in November.

On the supply side, markets adjusted expectations ahead of the December 6 meeting between the Organization of the Petroleum Exporting Countries (OPEC) and partner countries. Expectations that OPEC and its partners would extend or possibly deepen the cuts, as noted in
press reports, helped support crude oil prices. Ultimately, the group decided to deepen existing production cuts by 0.5 million b/d, but the cuts were not extended and continue to run through the end of March 2020.

EIA assumes the production cuts from OPEC and Russia will remain in place through the end of the forecast period in 2020. With production restraint from most OPEC members, continuing sanctions on Iran, and ongoing declines in Venezuela’s crude oil production, EIA expects OPEC production to fall in 2020. However, EIA forecasts that increased non-OPEC production will more than offset those declines and that global liquid fuels supply will rise by 1.5 million barrels per day (b/d) in 2020. EIA forecasts global fuels demand will rise by 1.4 million b/d next year and that Brent prices will average $61/b in 2020, down from $64/b in 2019. EIA expects the downward price pressures to be concentrated in the first half of 2020, when global oil inventories are forecast to rise. Prices will begin to rise in the second half of next year based on this STEO’s forecast of global oil inventory draws over that period.

**Brent and copper-to-gold ratio:** The price of copper—a commodity heavily used in construction and industrial production and, therefore, often positively correlated with economic expansion—has increased since reaching its year-to-date low in September relative to the price of gold. Gold is typically assumed to be a safe haven asset and its price tends to increase in times of economic uncertainty. Taken together, the ratio of these two commodity prices can indicate market sentiment on global economic growth.

As of December 5, copper-to-gold ratio increased to 0.93 (indexed to July 1, 2019) compared with a ratio of 0.84 on September 3, the lowest ratio in 2019 (Figure 2). The upward trend may reflect some improvement in the macroeconomic climate, which may have also contributed some support to the Brent price during the past two months. Supply issues can also affect commodity prices, as the September price spike in Brent after the attack on Saudi Arabia indicates. Part of the strength in copper prices also likely reflects the recent strikes, work slowdowns, and port closures in Chile, which produced 29% of the world’s copper in 2018.
**Crude oil trade flows:** Increasing U.S. crude oil exports and sanctions on Iranian crude oil sales have contributed to a significant shift in the waterborne oil trade in the Mediterranean and Red Seas, where traffic on the interconnecting Suez Canal has inverted. Ships transiting the Canal—through which 6% of all crude oil passed in 2018—had typically traveled northbound from the Red Sea into the Mediterranean, and northbound crude oil cargoes typically outnumbered their southbound counterparts by a ratio of about 2.8 to 1 between 2015 and 2018. This mismatch largely reflected the deep linkages between European buyers and major east-of-Suez producers such as Iraq, Saudi Arabia, and Iran, which supplied an average of 10%, 9%, and 15%, respectively, of crude oil imports to European countries in the Organization of Economic Cooperation and Development (OECD) between 2015 and 2018, according to data from the International Energy Agency (IEA). This group of Middle Eastern producers typically ship their Europe-bound crude oil cargoes to the Red Sea, where they then either navigate the Suez Canal or offload their cargoes onto the north-bound SUMED pipeline—though the attractiveness of the latter option has declined following the widening of the Canal in 2015. Since late 2018, however, northbound crude oil volumes on the Suez Canal have fallen in both absolute and relative terms, with the ratio of northbound to southbound October 2019 shipments falling to 0.4 to 1 for crude oil (Figure 3).

This reversal has likely been driven by two related factors. First, the increase in U.S. crude oil exports—which do not have to transit the Suez—has displaced some supplies from the former Soviet Union (FSU), primarily Russia, and the Middle East. According to the IEA, while the share of OECD Europe crude oil imports supplied by the FSU, Saudi Arabia, Iran, and Iraq fell from a combined 2015 to 2018 average of 68% to 62% in August 2019 (the latest date for which information is available), the U.S. share increased from 3% to 8% during the same period (Figure 4). Consequently, some Russian exporters have opted to send their cargoes south and east into the faster-growing Asian markets, increasing the number of southbound transits, while Middle Eastern exporters are also sending more cargoes to Asia, decreasing the number of northbound transits. Second, the volume of northbound cargoes has also been affected by U.S. sanctions on...
Iran that were reimposed in November 2018. By limiting the ability of Iranian cargoes to reach OECD Europe, the sanctions have contributed to the collapse in Iranian exports to the region from an annual average 536,000 b/d in 2018 to 25,000 b/d in August 2019.

These trends could continue in 2020 based on EIA’s supply forecasts and the International Maritime Organization (IMO) 2020 regulations. EIA expects U.S. crude oil production to provide about two-thirds of total global liquids growth next year, but OPEC production is forecast to decline. In addition, U.S. crude oil tends to be light, sweet grades, which will likely see an increase in global demand because of the IMO 2020 regulations.

**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) settled at $1.62 per gallon (gal) on December 5, down 3 cents/gal since November 1 (Figure 5). The RBOB–Brent crack spread (the difference between the price of RBOB and the price of Brent crude oil) decreased by 8 cents/gal to settle at 11 cents/gal during the same period.
The RBOB–Brent crack spread for November remained relatively stable, within a range of 8 cents/gal, and averaged 5 cents less than October and 3 cents/gal less than the five-year (2014–18) monthly average. One factor likely contributing downward pressure on the spread was an inventory build of 12.6 million barrels in November, which increased inventory levels to higher than the five-year monthly average after falling lower than the five-year average in October. Higher production and lower consumption in November compared with October contributed to the stock build.

**Ultra-low sulfur diesel prices:** The ultra-low sulfur diesel (ULSD) front-month futures price settled at $1.93/gal on December 5, unchanged from November 1. The ULSD–Brent crack spread (the difference between the price of ULSD and the price of Brent crude oil) decreased 4 cents/gal to settle at 42 cents/gal during the same period (**Figure 6**).
Although the average ULSD–Brent crack spread in November declined from the October level, it remained higher than the five-year average. Higher U.S. distillate fuel production and imports helped to moderate crack spreads in November. Distillate production increased from October as refineries came back from maintenance and increased throughput, but production remained lower than the five-year average. An increase in distillate imports and a decrease in exports resulted in net imports rising to higher than the five-year range. If confirmed in the monthly data, this level of net distillate imports would be the highest for November since 2012.

Distillate consumption also reached what would be a record high for November if confirmed by monthly data. Colder-than-normal temperatures and a late harvest contributed to distillate consumption in November of 4.2 million barrels per day. Despite the increases in production and net imports, the increase in distillate consumption led to a smaller-than-normal inventory build for November. EIA estimates the end of November inventory at 120 million barrels, the lowest level for November in seven years. EIA expects that the lower inventory levels combined with the upcoming International Maritime Organization (IMO) 2020 change to marine fuel sulfur specifications will contribute to higher ULSD-Brent crack spreads during the next several months.

**Midwest crack spreads**: Product market dynamics in the Midwest are creating different trends in gasoline and ULSD crack spreads for the Chicago area compared with New York Harbor and the Gulf Coast. In late November, refinery utilization rates in the Midwest (PADD 2), reached 94.4%, the highest across U.S. regions. Although total motor gasoline inventories in the Midwest ended November 1% higher than the five-year average, distillate inventories were 11% lower than the five-year average, likely a result of higher demand.

Because the Midwest has the largest regional consumption of distillate in the United States and the largest distillate consumption for farming end-use, factors specific to the farming sector likely contributed to the elevated consumption levels in the region. According to data from the U.S. Department of Agriculture and trade press reports, heavy rainfall and flooding delayed the crop harvest in the Midwest from October to November. Crack spreads responded by remaining high for ULSD and decreasing for gasoline. The average monthly Chicago ULSD-WTI crack spread in November decreased 1 cent/gal from October, and the Chicago RBOB-WTI crack spread decreased 12 cents/gal (**Figure 7**).
Residual fuel oil sulfur spread: The price spread between low- and high-sulfur residual fuel continued to widen in November (Figure 8), likely related to the upcoming IMO 2020 change in marine fuel sulfur specifications. Prices for high-sulfur residual fuel oil have been falling for most of the year, but prices for low-sulfur residual fuel oil have remained mostly flat, increasing the price differential between the two fuels. The price for high-sulfur (3%) residual fuel oil in New York Harbor (NYH) has fallen by $23.23 per barrel (b) from this time last year to $40.82/b in November 2019. During the same time period, the price for low-sulfur (0.3%) residual fuel oil in NYH has decreased $0.61/b to $76.91/b in November 2019. This difference in price performance indicates that the increase in the price differential between NYH low-sulfur and high-sulfur residual fuel oil of $22.62/b has been driven by the decrease in the high-sulfur residual fuel oil price.
EIA forecasts that demand for high-sulfur residual fuel oil in the bunkering market will shift to low-sulfur alternatives as a result of the IMO specification change. To prepare for this demand shift, ship operators have started to replace their high-sulfur fuel oil stores with low-sulfur fuels, which has contributed to the increase in the differential between low- and high-sulfur residual fuel oil.

**Natural Gas**

**Prices:** The front-month natural gas futures contract for January delivery at the Henry Hub settled at $2.43 per million British thermal units (MMBtu) on December 5, down 29 cents/MMBtu from November 1 (Figure 9). Forecasts for colder weather in early November—seen in Figure 9 as the sharp, green peak in the difference between normal and current heating degree days (HDD) in November 2019—had supported a sharp increase in futures prices from $2.24/MMBtu on October 21 to a peak of $2.86/MMBtu on November 5. For the rest of the month, prices declined in tandem with generally milder weather forecasts. The decline would have been more substantial, but the front-month natural gas futures price gained 6 cents/MMBtu with the change from December to January delivery on November 27.

**Inventories:** A similar increase in HDD occurred in November 2018, but the corresponding Henry Hub front-month futures price rose significantly more than in 2019. Natural gas inventory during November 2018 declined to more than 700 billion cubic feet lower than the five-year (2013–17) average (Figure 10), which likely contributed to the larger price response. Increasing production contributed to substantial inventory builds following the 2018 winter season, sending the total to near the five-year (2014–18) average in November 2019. The higher inventory level likely dampened the increases in the front-month futures price increases during November 2019. EIA estimates that natural gas production will remain at or lower than the November 2019 level through the end of 2020.
Notable forecast changes

- EIA revised historical global (outside of the United States) liquid fuels consumption data back to 2000. These revisions were most significant for countries in Africa and the Middle East. Based on these changes, EIA estimates that global liquid fuels consumption in 2017, the most recent year for which EIA has a complete set of consumption data, averaged 98.6 million barrels per day (b/d), 250,000 b/d lower than previously estimated. The lower 2017 consumption levels result in lower estimated and forecast consumption from 2018 through 2020.

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