Forecast highlights

Winter Fuels Outlook

- EIA forecasts that average household expenditures for all major home heating fuels, except heating oil, will increase this winter largely because of higher expected energy consumption. Average increases vary by fuel. Compared with last winter, EIA forecasts natural gas expenditures will increase by 6%, electricity by 7%, and propane by 14%. Home heating oil expenditures in EIA’s forecast fall by 10%, driven primarily by a combination of low crude oil prices and high distillate fuel oil supplies heading into the winter. EIA generally expects more space heating demand this winter compared with last winter based on forecasts from the National Oceanic and Atmospheric Administration (NOAA) that indicate colder winter temperatures. U.S. average heating degree days in this forecast are 5% higher than last winter. In addition, EIA expects that ongoing 2019 novel coronavirus disease (COVID-19) mitigation efforts and more people working and attending school at home will contribute to higher levels of home heating use this winter than in previous years (Winter Fuels Outlook).

Global liquid fuels

- The October Short-Term Energy Outlook (STEO) remains subject to heightened levels of uncertainty because mitigation and reopening efforts related to COVID-19 continue to evolve. Reduced economic activity related to the COVID-19 pandemic has caused changes in energy demand and supply patterns in 2020 and will continue to affect these patterns in the future. This STEO assumes U.S. gross domestic product (GDP) declined by 4.4% in the first half of 2020 from the same period a year ago. It assumes that GDP will rise beginning in the third quarter of 2020, and will grow 3.5% year-over-year in 2021. The U.S. macroeconomic assumptions in this outlook are based on forecasts by IHS Markit.

- Brent crude oil spot prices averaged $41 per barrel (b) in September, down $4/b from the average in August. The decrease in oil prices coincided with slowing increases in global oil demand. Month-over-month consumption rose by 1.0 million b/d on average during August and September compared with an increase of 4.1 million b/d from May through July. EIA estimates that global oil markets have shifted from global liquid fuels inventories building at a rate of 7.3 million barrels per day (b/d) in the second quarter of 2020 to drawing at a rate of 3.1 million b/d in the third quarter. EIA expects inventory
draws in the fourth quarter to be 3.0 million b/d before markets become more balanced, with inventory draws of 0.3 million b/d on average in 2021. Despite expected inventory draws in the coming months, EIA expects high inventory levels and surplus crude oil production capacity will limit upward pressure on oil prices. EIA forecasts monthly Brent spot prices will average $42/b during the fourth quarter of 2020 and will rise to an average of $47/b in 2021.

- EIA estimates that global consumption of petroleum and liquid fuels averaged 95.3 million b/d in September. Liquid fuels consumption was down 6.4 million b/d from September 2019, but it was up from an average of 85.1 million b/d during the second quarter of 2020 and 93.9 million b/d in August. EIA forecasts that global consumption of petroleum and liquid fuels will average 92.8 million b/d for all of 2020, down by 8.6 million b/d from 2019, before increasing by 6.3 million b/d in 2021. EIA’s forecast for consumption growth in 2021 is 0.3 million b/d less than in the September STEO.

- EIA reported that U.S. crude oil production averaged 11.0 million b/d in July (the most recent month for which historical data are available), up 0.5 million b/d from June. In May, U.S. crude oil production reached a two-and-a-half-year low of 10.0 million b/d, resulting from curtailed production amid low oil prices. Since then, U.S. production has increased mainly because tight oil operators have brought wells back online in response to rising prices. EIA estimates that production rose to 11.2 million b/d in September. However, EIA expects U.S. crude oil production to generally decline to an average of 11.0 million b/d in the second quarter of 2021 because new drilling activity will not generate enough production to offset declines from existing wells. EIA expects drilling activity to rise later in 2021, contributing to U.S. crude oil production returning to 11.2 million b/d in the fourth quarter of 2021. On an annual average basis, EIA expects U.S. crude oil production to fall from 12.2 million b/d in 2019 to 11.5 million b/d in 2020 and 11.1 million b/d in 2021.

**Natural Gas**

- In September, the Henry Hub natural gas spot price averaged $1.92 per million British thermal units (MMBtu), down from an average of $2.30/MMBtu in August. Lower natural gas spot prices reflected declining demand for natural gas from the U.S. electric power sector as a result of cooler-than-normal temperatures during the second half of September and relatively low demand for U.S. liquefied natural gas (LNG) exports amid hurricane-related activity in the Gulf of Mexico. EIA expects that rising domestic demand for natural gas and demand for LNG exports heading into winter, combined with reduced production, will cause Henry Hub spot prices to rise to a monthly average of $3.38/MMBtu in January 2021. EIA expects that monthly average spot prices will remain higher than $3.00/MMBtu throughout 2021, averaging $3.13/MMBtu for the year, up from a forecast average of $2.07/MMBtu in 2020.
• EIA estimates that total U.S. working natural gas in storage ended September at more than 3.8 trillion cubic feet (Tcf), 12% more than the five-year (2015–19) average. In the forecast, EIA expects inventories to be more than 4.0 Tcf on October 31, which would be a record high. However, because expected natural gas production will be lower this winter than last winter, EIA forecasts inventory draws will outpace the five-year average during the heating season and end March 2021 at 1.7 Tcf, which would be 6% lower than the 2016–20 average.

• EIA expects that total U.S. consumption of natural gas will average 83.7 billion cubic feet per day (Bcf/d) in 2020, down 1.8% from 2019. The decline in total U.S. consumption reflects less heating demand in early 2020, contributing to residential and commercial demand in 2020 averaging 13.1 Bcf/d (down 0.7 Bcf/d from 2019) and 8.7 Bcf/d (down 0.9 Bcf/d from 2019), respectively. EIA forecasts industrial consumption will average 22.3 Bcf/d in 2020, down 0.8 Bcf/d from 2019 as a result of reduced manufacturing activity. EIA expects total U.S. natural gas consumption will average 78.7 Bcf/d in 2021, a 5.9% decline from 2020. The expected decline in 2021 is the result of rising natural gas prices that will reduce demand for natural gas in the electric power sector.

• EIA forecasts U.S. dry natural gas production will average 90.6 Bcf/d in 2020, down from an average of 93.1 Bcf/d in 2019. In the forecast, monthly average production falls from a record 97.0 Bcf/d in December 2019 to 85.9 Bcf/d in May 2021, before increasing slightly. Natural gas production declines the most in the Permian region, where EIA expects low crude oil prices will reduce associated natural gas output from oil-directed rigs. EIA’s forecast of dry natural gas production in the United States averages 86.8 Bcf/d in 2021. EIA expects production to begin rising in the second quarter of 2021 in response to higher natural gas and crude oil prices.

• EIA estimates that U.S. LNG exports averaged 4.9 Bcf/d in September, an increase of 1.2 Bcf/d from August. Higher global forward prices indicate improving netbacks for buyers of U.S. LNG in European and Asian markets for the upcoming fall and winter seasons. The increased prices come amid expectations of natural gas demand recovery and potential LNG supply reductions because of maintenance at the Gorgon LNG plant in Australia. EIA forecasts that U.S. LNG exports will return to pre-COVID levels by November 2020 and will average more than 9.0 Bcf/d from December 2020 through February 2021.

Electricity, coal, renewables, and emissions

• EIA forecasts 2.2% less electricity consumption in the United States in 2020 compared with 2019. EIA expects retail sales of electricity to fall by 6.2% this year in the commercial sector and by 5.6% in the industrial sector. EIA forecasts residential sector retail sales will increase by 3.2% in 2020. Milder winter temperatures earlier in the year led to lower consumption for space heating, offset by increased summer cooling demand and increased electricity use by more people working and attending classes
from home. In 2021, EIA forecasts total U.S. electricity consumption will be similar to 2020 consumption. Higher forecast electricity consumption in the first quarter of 2021 because of an increase in demand for space heating is mostly offset by lower forecast electricity consumption in the third quarter of 2021 because of less cooling demand based on NOAA forecast of fewer cooling degree days.

- EIA expects the share of U.S. electric power sector generation from natural gas-fired power plants will increase from 37% in 2019 to 39% this year. In 2021, the forecast natural gas share declines to 34% in response to higher natural gas prices. Coal’s forecast share of electricity generation falls from 24% in 2019 to 20% in 2020 and then returns to 24% in 2021. Electricity generation from renewable energy sources rises from 17% in 2019 to 20% in 2020 and to 22% in 2021. The increase in the share from renewables is the result of planned additions to wind and solar generating capacity. EIA expects 3% declines in nuclear generation in both 2020 and 2021, reflecting recent and planned retirements of nuclear generating capacity. The nuclear share of U.S. generation remains close to 20% in all years.

- In 2020, EIA expects U.S. residential electricity prices to average 13.1 cents per kilowatthour, which would be 0.4% higher than the average electricity price in 2019. Annual changes in regional residential electricity prices range from 1.4% lower prices in the South Atlantic region to 4.0% higher prices in the Pacific region.

- EIA forecasts that renewable energy will be the fastest-growing source of electricity generation in 2020. EIA expects the U.S. electric power sector will add 23.3 gigawatts (GW) of new wind capacity in 2020 and 7.3 GW of new capacity in 2021. Expected utility-scale solar capacity rises by 13.7 GW in 2020 and by 11.8 GW in 2021.

- EIA expects total U.S. coal production in 2020 to be 525 million short tons (MMst), compared with 705 MMst in 2019, a 26% decrease. COVID-19 and efforts to mitigate it along with reduced demand from the U.S. electric power sector amid low natural gas prices have contributed to mine idling and mine closures. EIA expects production to rise to 625 MMst in 2021, up 19% from 2020. This forecast increase reflects rising demand for coal from U.S. electricity generators because of higher natural gas prices compared with 2020.

- EIA forecasts that U.S. energy-related carbon dioxide (CO2) emissions, after decreasing by 2.6% in 2019 from the previous year’s level, will decrease by 10% (536 million metric tons) in 2020 as a result of reduced consumption of all fossil fuels. EIA expects emissions from coal will be down 19% from 2019 and emissions from petroleum will be down 13% from 2019. This decline in emissions is the result of less energy consumption related to slowing economic growth related to COVID-19 and efforts to mitigate it. In 2021, EIA forecasts that energy-related CO2 emissions will increase by 5.4% from the 2020 level as the economy recovers and energy use increases.
Petroleum and natural gas markets review

Crude oil

**Prices:** The front-month futures price for Brent crude oil settled at $40.93 per barrel (b) on October 1, 2020, a decrease of $4.65/b from September 1, 2020. The front-month futures price for West Texas Intermediate (WTI) crude oil for delivery at Cushing, Oklahoma, decreased by $4.04/b during the same period, settling at $38.72/b on October 1 (Figure 1).

![Figure 1. Crude oil front-month futures prices](image)

During early September’s heightened volatility, Brent crude oil prices fell to less than $40/b then began to stabilize from mid-September through October 1, trading at an average level of $42/b. Some of the initial decline in prices came as a result of announcements that opposing parties in Libya had agreed to lift the export blockade that had reduced production in the country from 0.8 million b/d in January (the month before the blockade began) to less than 0.1 million b/d in August (the month before the blockade was lifted).

Because Libya is excluded from the current production agreement among members of the Organization of the Petroleum Exporting Countries and partner countries (OPEC+), an increase in crude oil production from the country could significantly affect crude oil supply and inventories in the coming months. In addition, EIA estimates the rate of global oil demand growth slowed in August and September compared with the initial recovery from June and July. June and July’s global oil demand increased by 6.0 million barrels per day (b/d) and 3.1 million b/d, respectively, whereas EIA estimates August and September demand increased by 0.6 million b/d and 1.3 million b/d, respectively. Recent increases in cases of COVID-19 in some countries have led to some renewed government imposed restrictions, albeit to a much lesser extent than in March and April 2020, which could also be contributing to some downward pressure on crude oil prices.
*Brent–WTI futures price spread:* Three developments this year have contributed to a reduction in the Brent–WTI futures price spread, which closed at a four-month low of 48 cents/b on September 30 (Figure 2). First, the pace of crude oil production changes in the United States compared with the North Sea has likely affected the two crude oils’ relative prices and contributed to a narrowing of the price spread. The significant crude oil price decline in the second quarter resulted in a faster crude oil production response from U.S. crude oil producers, who curtailed or shut in some wells to avoid financial losses. Although U.S. crude oil production has risen since the second quarter, the estimated September 2020 production level in the United States is 1.0 million b/d lower than the 2019 annual average production level of 12.2 million b/d. In contrast, EIA estimates total production in Norway and the United Kingdom—much of which is delivered or priced against Brent crude oil—was slightly higher than the 2019 annual average in September of 2020. Because North Sea production has not declined while U.S. production has declined, it is likely putting downward price pressure on Brent relative to WTI.

Second, the pace of global oil demand recovery from the second quarter has been slower than EIA estimated in the September STEO. A higher share of crude oil demand from importers in Asia could be met from a combination of inventories as well as rising OPEC+ production. EIA expects this trend will persist as global demand recovers into 2021, which could reduce export demand for U.S. crude oil from the most distant refining markets in Asia.

Third, crude oil export infrastructure has continued to expand along the U.S. Gulf Coast, which has improved efficiency and lowered U.S. crude oil export costs. As a result of all these developments, EIA forecasts the Brent–WTI spread will average $1.50/b in the fourth quarter of 2020 and $2.35/b in 2021, a decrease of $1.50/b and $1.65/b, respectively, from the September STEO.
**Oil rigs:** Oil-directed rigs in the United States increased in September from 180 rigs as of the last week in August to 183 rigs as of September 25, according to the weekly rig count from Baker Hughes (Figure 3). September marked the first monthly increase in oil-directed rigs since the 2020 high of 683 oil-directed rigs in March.

![Figure 3. U.S. oil rigs and WTI prices](image)

Even as rigs declined during the summer, Lower 48 states’ (L48) production rose from 8.0 million b/d in May to an estimated 9.0 million b/d in the third quarter as a result of operators bringing curtailed wells back online. However, EIA forecasts L48 crude oil production will decline to an average of 8.6 million b/d in the first half of 2021. Most curtailed production has already been brought back online, and although EIA expects rig counts to increase in some of the most highly productive areas of the Permian region, the total L48 new drilling activity is not expected to generate enough production to offset declines from existing wells. Because EIA forecasts WTI prices to average at or higher than $45/b from May to December 2021, EIA assumes producers will increase drilling activity in response to the higher oil prices, and forecasts L48 production will return to an average of 8.9 million b/d in the fourth quarter of 2021.

**Market-derived probabilities:** The December WTI futures contract averaged $40.08/b for the five trading days ending October 1 and has a 20% probability of expiring higher than $45/b (Figure 4). The same contract for the five trading days ending September 1 had a 38% probability of expiring higher than $45/b. The probability is calculated from futures and options prices.
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 $1.15 per gallon (gal) on October 1, down 7 cents/gal from September 1, 2020 (Figure 5). The RBOB–Brent crack spread (the difference between the price of RBOB and the price of Brent crude oil) increased by 4 cents/gal to settle at 18 cents/gal during the same period. The average crack spread in September decreased from 20 cents/gal in August to average 18 cents/gal.

The transition to winter-grade gasoline and a decrease in gasoline consumption likely contributed to the decrease in the average crack spread from August. EIA estimates U.S. gasoline consumption totaled 8.5 million barrels per day (b/d) in September, down 0.3 million
b/d from August, and if confirmed in monthly data, it would be the lowest level for September since 1999. Nonetheless, the average crack spread came within the month’s five-year (2015–19) range for the first time since January 2020 as U.S. total motor gasoline stocks declined by 3.9 million barrels from August, the largest September draw since 2008, when Hurricanes Gustav and Ike made landfall in the Gulf Coast. Lost gasoline production because of storm-related refinery closures contributed to this stock decrease. According to trade press, Citgo’s 418,000 b/d Lake Charles refinery and Phillips 66’s 260,000 b/d Westlake plant are expected to remain shut through at least mid-October after closing from Hurricane Laura in late-August, and Phillips 66’s 255,600 b/d Alliance refinery, which was already scheduled for maintenance in October, has been shut since taking precautions for Hurricane Sally beginning on September 13.

**Ultra-low sulfur diesel prices:** The ultra-low sulfur diesel (ULSD) front-month futures price for delivery in New York Harbor settled at $1.13/gal on October 1, 2020, down 11 cents/gal from September 1, 2020 (Figure 6). The ULSD–Brent crack spread (the difference between the price of ULSD and the price of Brent crude oil) remained mostly unchanged at 15 cents/gal during the same period.

![Figure 6. Historical ULSD front-month futures price and crack spread](image)

The ULSD–Brent crack spread, which has averaged less than the five-year minimum in each of the past five months, was 27 cents/gal lower than the five-year average for September. Crack spreads decreased as consumption decreased and inventories remained high. EIA estimates that distillate consumption was 3.6 million b/d for September, down 5% from August’s estimate of 3.7 million b/d and down 9% from a year ago. EIA also estimates that distillate production decreased in September, falling to 4.4 million b/d, the lowest for any month since March 2013. Despite lower month-over-month production, distillate yields for much of 2020 have remained higher than the 2019 level. Although distillate demand has declined this year, jet fuel demand has declined by more. As a result, refineries have shifted production away from jet fuel and toward distillate, which has contributed to persistently high distillate fuel inventories and low distillate fuel crack spreads.
**August and September crack spreads:** The RBOB–Brent crack spread typically decreases from August to September because futures contracts switch to the cheaper winter-grade gasoline and consumption decreases as the summer driving months come to an end. This year, the crack spread decreased less than in previous years (Figure 7). Whereas the crack spread decreased in 2018 and 2019 by 17 cents/gal and 13 cents/gal, respectively, the crack spread only decreased by 2 cents/gal this year. The shallower decline this year likely reflects that the crack spread stayed at a lower level this summer because of lower gasoline demand as a result of more people working from home.

![Figure 7. August and September average crack spreads](image)

Unlike the RBOB–Brent crack spread, which typically decreases going into the fall, the ULSD–Brent crack spread typically increases. During the previous four years, the ULSD–Brent crack spread increased by an average of more than 2 cents/gal. In 2020, the crack spread decreased by 4 cents/gal, the largest August-to-September decrease in at least 10 years. The average crack spread for both months were at 10-year lows. As a result of gasoline’s relative price premium over distillate, refiners have accordingly been reconfiguring equipment to favor gasoline over middle distillates, according to trade press.

**Natural Gas**

**Prices:** The front-month natural gas futures contract for delivery at the Henry Hub settled at $2.53 per million British thermal units (MMBtu) on October 1, unchanged from September 1 (Figure 8). The front-month futures price fell sharply through September 22, when it reached a low of $1.83/MMBtu, before rising at the end of the month. On September 28, the contract for October delivery expired, and the spread between October delivery and November delivery was $0.69/MMBtu. The price spread between the first two natural gas contracts had reached $0.88/MMBtu on September 21, the widest inflation-adjusted spread between the first two natural gas futures contracts since October 2009.
Front-month natural gas futures prices decreased as a series of hurricanes and tropical storms in the U.S. Gulf Coast limited operations at some liquefied natural gas (LNG) export facilities, which can serve as a major source of natural gas demand. Both Cameron LNG and Sabine Pass LNG facilities reduced operations during the last week in August in advance of Hurricane Laura. Cameron LNG lost power until September 18, and continues to remain offline as a result of surrounding maritime infrastructure issues. EIA estimated that LNG exports in September were 4.9 billion cubic feet per day (Bcf/d), 8% less than the previous year and 39% lower than the amount exported at the peak in January 2020.

EIA also estimates that natural gas production declined to 89.4 Bcf/d in September, 5.3 Bcf/d lower than in September 2019. Despite falling production in 2020, falling LNG exports have contributed to high natural gas inventories. EIA estimates that U.S. natural gas inventories at the end of September reached a record high for the month of September and forecasts that inventory levels at the end of October could be the highest on record for any month.

**Natural gas futures price spreads:** In addition to the wide price spread between the first and second month natural gas futures contracts, the spread between natural gas prices for October 2020 delivery and January 2021 delivery was more than three times the five-year average in September (Figure 9) and the widest since 2009. The front-month futures price volatility was also higher; the contract for October delivery traded within an 88 cents/MMBtu range in September compared with a range of 32 cents/MMBtu for the January contract. The wide spread between these contracts reflects the current high level of inventories, but it also indicates that market participants expect the current oversupply situation to change in the next few months. EIA forecasts that production will continue to fall for the next several months and that LNG exports will grow rapidly and show year-on-year growth by October 2020. Those changes, combined with the usual seasonal increase in natural gas consumption, will begin to draw down inventories and tighten the market. EIA forecasts that natural gas inventories will decline to their monthly five-year average by January 2021.
Notable forecast changes

- EIA forecasts global consumption of petroleum and other liquid fuels will average 99.1 million barrels per day (b/d) in 2021, a decrease of 0.5 million b/d from the September STEO. The downward revision is primarily in India, which has realized larger economic declines in 2020 compared with initial estimates, which EIA expects will persist into 2021. In addition, EIA has reduced the 2021 global demand growth forecast as a result of a slower recovery in global jet fuel demand.

- EIA forecasts Brent crude oil prices to trade $2.35 per barrel (b) more than WTI prices in 2021. In the September STEO, EIA had forecast a $4.00/b spread in 2021. The narrower spread reflects EIA’s expectation of reduced demand for U.S. crude oil globally because of lower global oil demand amid lower U.S. crude oil production.

- EIA forecasts U.S. jet fuel consumption will average 1.1 million b/d in the fourth quarter of 2020, down from a forecast of 1.5 million b/d in the September STEO. The lower forecast reflects incoming data that show the recovery in jet fuel consumption, particularly by internationally-bound flights, is proceeding more slowly than EIA expected.

- EIA forecasts crude oil inputs at U.S. refineries will average 15.9 million b/d in 2021, which is 0.5 million b/d less than forecast last month. The lower expected refinery inputs reflect updates to EIA’s forecasting equation for crude oil refinery runs. The new equation uses U.S. petroleum demand and net petroleum product exports as explanatory variables, compared with refinery product margins and stock levels in the former equation.
EIA has revised its modeling for retail electricity prices so that forecast retail prices are now a function of regional wholesale electricity prices. Previously, EIA modeled regional retail electricity prices as a function of the average U.S. cost of natural gas and coal delivered to electric generators. Forecast wholesale prices reflect the cost of fossil fuel-fired generators along with the cost of supplying renewable electricity.