Global liquid fuels

- The February Short-Term Energy Outlook (STEO) remains subject to heightened levels of uncertainty because responses to COVID-19 continue to evolve. Reduced economic activity related to the COVID-19 pandemic has caused changes in energy demand and supply over the past year and will continue to affect these patterns in the future. U.S. gross domestic product (GDP) declined by 3.6% in 2020 from 2019 levels. This STEO assumes U.S. GDP will grow by 3.8% in 2021 and by 4.2% in 2022. The U.S. macroeconomic assumptions in this outlook are based on forecasts by IHS Markit.

- Brent crude oil spot prices averaged $55 per barrel (b) in January, up $5/b from the December average but $9/b lower than the average in January of last year. Higher Brent prices in January largely reflected the January 5 announcement by Saudi Arabia that it would unilaterally cut 1.0 million barrels per day (b/d) of crude oil production in February and March, in addition to the reduced production levels on which the Organization of the Petroleum Exporting Countries (OPEC) and partner countries (OPEC+) previously agreed. The U.S. Energy Information Administration (EIA) expects Brent crude oil prices will average $56/b in the first quarter of 2021 and $52/b over the remainder of the year. EIA expects lower oil prices later in 2021 as a result of rising oil supply that will slow the pace of global oil inventory withdrawals. EIA also expects that high global oil inventory levels and spare production capacity will limit upward price pressures. EIA expects Brent prices will average $55/b in 2022.

- EIA estimates that the world consumed 93.9 million b/d of petroleum and liquid fuels in January, which is down 2.8 million b/d from January 2020. EIA forecasts that global consumption of petroleum and liquid fuels will average 97.7 million b/d for all of 2021, which is up by 5.4 million b/d from 2020. EIA forecasts that consumption of petroleum and liquid fuel will increase by 3.5 million b/d in 2022 to average 101.2 million b/d.

- EIA estimates that U.S. crude oil production averaged 11.0 million b/d in January, which is down slightly from 11.1 million b/d in November (the most recent month for which historical data are available). EIA expects production will continue to decline slightly in the coming months, reaching 10.9 million b/d in June. Although oil-directed drilling has increased in the United States in recent months, the number of active drilling rigs remains lower than year-ago levels. EIA expects production from newly drilled wells will be more
than offset by declining production rates at existing wells in the first half of 2021. However, based on EIA’s forecast that West Texas Intermediate crude oil prices will remain near or higher than $50/b during the forecast period, EIA expects drilling will continue to increase. As a result, production from new wells will exceed the declines from legacy wells, and overall crude oil production will increase in the second half of 2021 and in 2022. EIA estimates that U.S. crude oil production will average 11.0 million b/d in 2021—down from 11.3 million b/d in 2020 and 12.2 million b/d in 2019—and will rise to 11.5 million b/d in 2022.

- U.S. regular gasoline retail prices averaged $2.33 per gallon (gal) in January, compared with an average of $2.20/gal in December and $2.55/gal in January 2020. EIA forecasts gasoline prices to average $2.44/gal in 2021 and $2.46/gal in 2022. U.S. diesel fuel prices averaged $2.68/gal in January compared with $2.58/gal in December and $3.05/gal in January 2020, and EIA forecasts it will average $2.70/gal in 2021 and $2.77/gal in 2022.

- On a volume basis, U.S. consumption of gasoline declined by more than other petroleum products in 2020. EIA forecasts that U.S. gasoline consumption will rise in the forecast but remain lower than 2019 levels. U.S. gasoline consumption is forecast to average 8.6 million b/d in 2021 and 8.9 million b/d in 2022, up from 8.0 million b/d in 2020 but lower than the 9.3 million b/d consumed in 2019.

**Natural Gas**

- EIA expects that total U.S. consumption of natural gas will average 81.7 billion cubic feet per day (Bcf/d) in 2021, down 1.9% from 2020. The decline in total U.S. consumption reflects less natural gas consumed for electric power as a result of higher natural gas prices compared with last year. In 2021, EIA expects residential natural gas demand to average 12.9 Bcf/d (up 0.2 Bcf/d from 2020) and commercial demand to average 9.1 Bcf/d (up 0.6 Bcf/d from 2020). EIA forecasts industrial consumption will average 23.0 Bcf/d in 2021 (up 0.4 Bcf/d from 2020) as a result of increased manufacturing activity amid a recovering economy. Industrial consumption of 23.0 Bcf/d would be 0.1 Bcf/d below the 2019 level. EIA expects total U.S. natural gas consumption will average 81.0 Bcf/d in 2022.

- In January, the Henry Hub natural gas spot price averaged $2.71 per million British thermal units (MMBtu), up from the December average of $2.59/MMBtu. EIA expects Henry Hub spot prices to reach a monthly average of $2.98/MMBtu in February 2021. Higher expected prices in February reflect expectations of continued strong liquefied natural gas (LNG) exports and a shrinking surplus of natural gas in storage compared with the five-year (2016–20) average. EIA uses weather forecasts from the National Oceanic and Atmospheric Administration (NOAA) as an input into the STEO, and the NOAA forecast in this STEO is from late January. More recent forecasts for mid-February weather show cold temperatures could extend across much of the United States, which creates an upside risk to near-term prices in this outlook. EIA expects that Henry Hub spot prices will average $2.95/MMBtu in
2021, which is up from the 2020 average of $2.03/MMBtu. EIA expects that continued growth in LNG exports and in domestic natural gas consumption outside of the electric power sector, as production remains relatively flat, will contribute to Henry Hub spot prices rising to an average of $3.27/MMBtu in 2022.

- U.S. working natural gas in storage ended October at more than 3.9 trillion cubic feet (Tcf), 5% more than the 2015–19 average and the fourth-highest end-of-October level on record. EIA estimates that inventory withdrawals were 703 billion cubic feet (Bcf) in January, compared with a five-year (2016–20) average January withdrawal of 716 Bcf. The January withdrawals occurred at a lower rate than EIA forecast in last month’s STEO. The lower-than-expected withdrawal is the result of warmer-than-average January temperatures that reduced natural gas use for space heating. However, EIA forecasts that declines in U.S. natural gas production this winter compared with last winter will more than offset the declines in natural gas consumption, which will contribute to natural gas storage returning to levels near the five-year average by the end of winter. Forecast natural gas inventories end March 2021 at 1.8 Tcf, which is about the same as the five-year average.

- EIA forecasts that U.S. production of dry natural gas will average 90.5 Bcf/d in 2021 and 91.0 Bcf/d in 2022, which are down from an average of 91.3 Bcf/d in 2020 and 93.1 Bcf/d in 2019. In the forecast, dry natural gas production remains relatively flat, averaging between 89.8 Bcf/d and 91.0 Bcf/d in every month from February 2021 through July 2022. Flat natural gas production is the result of falling production in several of the smaller natural gas producing regions being offset by growth in other regions, most notably in the Appalachia and Haynesville regions.

- EIA estimates that the United States exported 9.8 Bcf/d of LNG in January amid high spot natural gas prices in Asia. However, foggy conditions and high winds affected export operations at Sabine Pass LNG, Corpus Christi LNG, and Cameron LNG, leading to several weather-related closures and sporadic suspension of piloting services on several days in January. EIA forecasts that U.S. LNG exports will average 8.5 Bcf/d in 2021. In 2022, EIA forecasts LNG exports will average 9.2 Bcf/d, surpassing the amount of natural gas exported via pipeline for the first time.

Electricity, coal, renewables, and emissions

- EIA forecasts that consumption of electricity in the United States will increase by 1.6% in 2021 after falling 3.8% in 2020. EIA forecasts residential sector retail sales will grow by 2.2% in 2021. The increase is primarily a result of colder forecast temperatures in the first quarter of 2021 compared with the same period in 2020, which EIA expects will raise demand for space heating, along with EIA’s assumption that more people will be working from home than in the first quarter of 2020. EIA expects retail sales of electricity in the commercial and industrial sectors will increase by 1.2% and 2.3%, respectively. For 2022, EIA forecasts total electricity consumption will grow by another 1.7%.
EIA expects the share of U.S. electric power generated with natural gas to fall from 39% in 2020 to 37% in 2021 and to 35% in 2022. The forecast natural gas share declines in response to a forecast increase in the price of natural gas delivered to electricity generators from an average of $2.38/MMBtu in 2020 to $3.27/MMBtu in 2021 (a 37% increase). Coal’s forecast share of electricity generation rises from 20% in 2020 to 21% in 2021 and to 22% in 2022. Electricity generation from renewable energy sources rises from 20% in 2020 to 21% in 2021 and to 23% in 2022. The nuclear share of U.S. generation declines from 21% in 2020 to 20% in 2021 and to 19% in 2022.

EIA forecasts that planned additions to U.S. wind and solar generating capacity in 2021 and 2022 will contribute to increasing electricity generation from those sources. EIA estimates that the U.S. electric power sector added 17.5 gigawatts (GW) of new wind capacity in 2020. EIA expects 15.3 GW of wind capacity will be added in 2021 and 3.6 GW in 2022. Utility-scale solar capacity rose by an estimated 11.1 GW in 2020. The forecast for added utility-scale solar capacity is 16.2 GW for 2021 and 12.3 GW for 2022.

EIA expects U.S. coal production to total 589 MMst in 2021, 50 MMst (9%) more than in 2020. In 2022, EIA expects coal production to rise by a further 5 MMst (1%). These increases reflect higher forecast demand for coal in the electric power sector because of rising natural gas prices, which increases coal’s competitiveness relative to natural gas for power generation dispatch. Although EIA expects coal production to rise in 2022, expected production increases will be limited by strong inventory draws. EIA expects significant coal supply to the power sector will come from a reduction in inventory levels in 2022, as the power sector brings inventory levels back in line with historical averages. Coal production in the forecast will also be limited by declining production capacity, as high mine reclamation costs have contributed to mine divestments and closings that may counter the effects of higher coal demand.

EIA expects rising global economic activity will contribute to rising steel production and power demand, which will lead to increased U.S. exports of both metallurgical and steam coal. EIA forecasts coal exports will total 85 MMst in 2021, up by 24% from 2020, which was the lowest level since 2016. EIA forecasts exports will rise by 6 MMst in 2022 to 91 MMst.

EIA estimates that U.S. energy-related carbon dioxide (CO2) emissions decreased by 11% in 2020. This decline in emissions is the result of less energy consumption related to economic contraction in response to the COVID-19 pandemic. In 2021, EIA forecasts that energy-related CO2 emissions will increase by about 4% from the 2020 level as economic activity increases leading to rising energy use. Energy-related CO2 emissions are also expected to rise by 3% in 2022 as economic growth continues.
Petroleum and natural gas markets review

Crude oil

**Prices:** The front-month futures price for Brent crude oil settled at $58.84 per barrel (b) on February 4, 2021, an increase of $7.75/b from January 4, 2021. The front-month futures price for West Texas Intermediate (WTI) crude oil for delivery at Cushing, Oklahoma, increased by $8.61/b during the same period, settling at $56.23 on February 4 (Figure 1).

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

Sustained production cuts by the Organization of the Petroleum Exporting Countries (OPEC) and partner countries (OPEC+) continued to put upward pressure on crude oil prices in January. In early December, OPEC+ announced it would limit production increases planned for early 2021. Then in early January, OPEC+ largely reaffirmed those limits, and Saudi Arabia announced on January 5 that it would unilaterally cut an additional 1.0 million barrels per day (b/d) of production in February and March.

In addition to the OPEC+ supply reductions, expectations for increasing petroleum demand as a result of the rollout of COVID-19 vaccines are further supporting oil prices. Brent crude oil prices settled at more than $55/b on all but one day since January 8, marking the highest levels since the early days of the pandemic in late-February 2020. However, new government mobility restrictions in response to COVID-19 during the Lunar New Year holiday season in China and increased restrictions on travel in Europe both present the potential to keep petroleum demand lower than might otherwise be expected.

EIA expects that global consumption of petroleum and liquid fuels will rise by 5.4 million b/d in 2021, which is 0.2 million b/d less than forecast in last month’s STEO. That pace of growth would bring global petroleum and liquid fuels consumption to an average of 97.7 million b/d for the year, still 3.5 million b/d less than in 2019.
Crude oil futures price spreads and floating storage: The crude oil market developed large contango (when near-term prices are lower than longer-dated ones) in April and May 2020 because a significant reduction in demand for crude oil reduced front-month futures contract prices. The magnitude of the contango narrowed in the summer, as crude oil production decreased and petroleum demand increased.

In early December, when the front-month Brent contract changed to February delivery, the spread became consistently backwardated (when near-term prices are higher than longer-dated ones). Backwardation developed as a result of market assessments that the rollout of the COVID-19 vaccine would contribute to rising oil demand in early 2021, combined with early December announcements of limited production increases from OPEC+ in the first quarter of 2021. EIA weekly data from January confirm near-term tightness in oil markets. EIA estimates U.S. crude oil inventories fell by 9.8 million barrels in January, compared with a five-year average build of 12.1 million barrels. Also, U.S. refinery inputs of crude oil increased in January compared with December. Typically refinery inputs decline in January.

This slight backwardation persisted through December, and then it increased significantly in January, when front-month crude oil prices reached 11-month highs. The Brent 1st–13th spread settled at $4.11/b and the WTI 1st–13th spread settled at $4.43/b on February 4, 2021 (Figure 2). This increase in backwardation is most likely the result of Saudi Arabia’s announced supply cuts for February and March, which EIA expects will contribute to global oil stock withdrawals during the first quarter of 2021. EIA forecasts first-quarter 2021 global oil stock withdrawals to average 2.0 million b/d, down only slightly from the high withdrawal rates during the second half of 2020.

Figure 2. Crude oil front-month to 13th month futures price spread

The sharp contango in April and May 2020 was the result of substantial decreases in demand for liquid fuels in the first half of 2020 because of responses to the pandemic, which contributed to significant increases in crude oil inventories. As onshore crude oil storage began to fill, many
market participants resorted to storing crude oil in floating storage, which peaked at 222 million barrels during the week of June 26, 2020, according to energy analytics company, Vortexa (Figure 3). Vortexa defines floating storage as the amount of crude oil on tankers that has been stationary for at least seven days. The initial growth in floating storage through June occurred across several regions. Both the Pacific and Atlantic basin markets stored crude oil when demand rapidly decreased. Current levels of backwardation indicate a need for inventory drawdowns to meet demand, suggesting current levels of floating storage may continue to decline.

As crude oil production fell and demand gradually increased, floating storage began to decline in Europe and other Atlantic Basin markets, but high Chinese crude oil purchases amid lower global crude oil prices resulted in increases in port congestion and floating storage off the Chinese coast. Floating storage declined by 32 million barrels globally between when the market entered backwardation in late November through late-January, before increasing at the end of the month. Vortexa reports that floating storage was 110 million barrels as of January 29, 2021, down 111 million barrels since June. EIA discussed the connection between Chinese crude oil imports, floating storage, and crude oil futures last October in This Week in Petroleum. Crude oil in floating storage has declined closer to levels observed in first-quarter 2020, but a combination of global oil demand and refinery runs that are still lower than year-ago levels is likely contributing to a near-term plateau of floating storage.

**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 $1.64 per gallon (gal) on February 4, up 27 cents/gal from January 4 (Figure 4). The RBOB–Brent crack spread (the difference between the price of RBOB and the price of Brent crude oil) increased by 9 cents/gal to settle at 24 cents/gal during the same period.
In the United States, expectations of increased domestic consumption likely contributed to upward pressure on the RBOB–Brent crack spread in January. EIA forecasts gasoline consumption will average 8.5 million barrels per day (b/d) from February to June, compared with consumption in January, which EIA estimates at 7.8 million b/d.

**March to April RBOB contract spread:** The RBOB futures contract for April delivery is the first contract during the year that trades the more-expensive-to-produce summer-grade gasoline. As a result, April contracts typically trade at a premium to March contracts. On the final trading day in January in the past five years, the average spread between RBOB contracts for April delivery and RBOB contracts for March delivery was 19 cents/gal *(Figure 5).* In 2021, that spread was 10 cents/gal, the lowest since 2009. The relatively low spread this year likely indicates that expectations of a seasonal increase in spring and summer driving will be more subdued than in previous years. Additionally, the spread may be lower because refinery utilization levels are relatively low, and the marginal cost of increasing summer-grade gasoline production from a low baseline may be lower than under normal utilization rates.
Ultra-low sulfur diesel prices: The front-month futures price for ultra-low sulfur diesel (ULSD) for delivery in New York Harbor settled at $1.70/gal on February 4, up 24 cents/gal from January 4 (Figure 6). The ULSD–Brent crack spread (the difference between the price of ULSD and the price of Brent crude oil) increased by 5 cents/gal to settle at 30 cents/gal during the same period. January’s average ULSD–Brent crack spread of 26 cents/gal was the highest since March 2020.

The ULSD-Brent crack spread generally increased throughout January and has continued to increase in early February. Higher estimated consumption in January likely contributed upward pressure to the crack spread, which has increased for four consecutive months. EIA estimates distillate consumption increased 0.36 million b/d (10%) from December to 4.01 million b/d in January. Because of the wide price spread between ULSD traded at New York Harbor and low
sulfur gasoil traded in Europe, U.S. net imports have been relatively high, contributing to a stock build of 3.9 million barrels (2.5%) in January. If confirmed by monthly data, January net imports were the highest for that month since 2011, and the January 2021 closing stock level was the highest for the month since 2017.

**Natural Gas**

**Prices:** The front-month natural gas futures contract for delivery at the Henry Hub settled at $2.94 per million British thermal units (MMBtu) on February 4, 2021, which is up 35 cents/MMBtu from January 4, 2021 (Figure 7).

A shift to a colder weather outlook for the first half of February contributed to a substantial increase in the futures prices on February 1. The front-month contract settled at a higher price on February 1 than all trading days in January, which was the first time since 2014 that a February price settlement exceeded all of the closing prices from the previous month. U.S. temperatures in January were warmer-than-average but colder than January 2020, which helped to keep consumption nearly unchanged from the previous year and to moderate Henry Hub prices despite significant increases in natural gas prices in Europe and Asia because of colder weather in those regions.

EIA estimates that in January 2021, U.S. LNG exports reached record levels for the third consecutive month. U.S. dry natural gas production in January declined for the second consecutive month, but it experienced the smallest year-on-year decrease in six months. EIA estimates that U.S. inventory levels at the end of January remained 9% higher than the five-year (2016–20) average, but it forecasts that inventories will decline to lower than the five-year average by the end of March 2021.
International natural gas prices: Liquefied natural gas (LNG) spot and forward prices in northern Asia approached an all-time high in mid-January 2021 (Figure 8). Sustained cold temperatures in Japan, China, and South Korea—the world’s three largest LNG consumers—prompted an increase in space heating demand, a drawdown in LNG inventories, and an increase in LNG prices. LNG shipping constraints because of congestion at the Panama Canal and unplanned outages at multiple LNG export facilities were also significant contributors.

In Japan, several power utilities were faced with critically low LNG inventories and purchased additional LNG volumes in global spot markets on a short-term basis. In northern China, the decline in temperatures to a five-decade low led to increased LNG imports, which in December 2020 reached the largest monthly LNG import volume in China to date. In South Korea, several coal plants were taken offline during the winter to reduce air pollution, requiring higher output from natural gas power plants.

Aside from the significant demand increase, unplanned outages at a number of LNG export facilities in several countries also contributed to reduced global LNG supply. Typically, LNG export facilities run at maximum capacity in the winter because more than 97% of global LNG consumption occurs in the northern hemisphere, where regasified LNG is used for space heating and the use of LNG depends on prevailing weather conditions. EIA estimates that in December 2020, global LNG export capacity was utilized at 88%—the lowest level for the month in at least six years.
Notable forecast changes

• EIA forecasts Federal U.S. Gulf of Mexico crude oil production will average almost 1.7 million barrels per day (b/d) in both 2021 and 2022, which is 0.1 million b/d lower than previously forecast. The reduced forecast reflects both announcements by operators that they will push back the start dates of several fields as well as initial production rates that were lower than EIA’s previous expectations at fields that came online in the second half of 2020.

• EIA expects marketed natural gas production to average 98.3 billion cubic feet per day in the United States (Bcf/d) in 2021 and 98.9 Bcf/d in 2022, up 2.4 Bcf/d and 1.3 Bcf/d, respectively, from the January forecast. The upward revision reflects more forecast associated natural gas production from oil-directed wells in the Permian region.

• EIA expects natural gas use for power generation will total 1,430 billion kilowatthours (kWh) in 2021 and 1,397 billion kWh in 2022, which are up 3% and 5%, respectively, from the January STEO. The higher forecast reflects lower regional natural gas price assumptions in EIA’s electricity generation model. The lower prices also reduce coal use for power generation in the forecast. EIA expects coal-fired power generation will total 835 billion kWh in 2021 and 888 billion kWh in 2022, which are down 4% and 7%, respectively, from the January STEO.

• EIA expects coal production to total 594 million short tons in 2022, which is 5% less than forecast in the January STEO. The lower forecast is the result of lower forecast coal use in the electric power sector.

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