Forecast highlights

Global liquid fuels

- The February Short-Term Energy Outlook (STEO) assumes U.S. GDP grew by 5.7% in 2021 and will grow by 4.2% in 2022 and by 2.8% in 2023. We use the IHS Markit macroeconomic model to generate our U.S. economic assumptions. Global macroeconomic assumptions in this forecast are from Oxford Economics and include global GDP growth of 4.4% in 2022 and 4.0% in 2023, compared with growth of 5.8% in 2021. A wide range of potential macroeconomic outcomes could significantly affect energy markets during the forecast period. In addition, the evolving effects of consumer behavior on energy demand because of the pandemic present a wide range of potential outcomes for energy consumption. Supply uncertainty in the forecast results from the potential for disruptions, the production decisions of OPEC+, and the rate at which U.S. oil and natural gas producers increase drilling.

- Brent crude oil spot prices averaged $87 per barrel (b) in January, a $12/b increase from December 2021. Crude oil prices have risen steadily since mid-2020 as result of consistent draws on global oil inventories, which averaged 1.8 million barrels per day (b/d) from the third quarter of 2020 (3Q20) through the end of 2021. We estimate that global oil inventories fell further in January—compared with our expectation of an increase in last month’s STEO—and that commercial inventories in the OECD ended the month at 2.68 billion barrels, which is the lowest level since mid-2014. Oil prices have also risen as result of heightened market concerns about the possibility of oil supply disruptions, notably related to tensions regarding Ukraine, paired with receding market concerns that the Omicron variant of COVID-19 will have widespread effects on oil consumption.

- We expect Brent prices will average $90/b in February as continuing draws in global oil inventories in our forecast keep crude oil prices near current levels in the coming months. However, we expect downward price pressures will emerge in the middle of the year as growth in oil production from OPEC+, the United States, and other non-OPEC countries outpaces slowing growth in global oil consumption. This dynamic leads to rising global oil inventories from 2Q22 through the end of 2023, and we forecast the Brent spot price will fall to an average of $87/b in 2Q22 and $75/b in 4Q22. We expect the Brent price will average $68/b for all of 2023. However, low inventory levels create an environment for potentially heightened crude oil price volatility and potential risk for
prices to rise significantly if supply growth does not keep pace with demand growth. Global supply chain disruptions have also likely exacerbated inflationary price effects across all sectors in recent months. How central banks respond to inflation may affect economic growth and oil prices during the forecast period.

- We estimate that 99.0 million b/d of petroleum and liquid fuels was consumed globally in January 2022, an increase of 6.6 million b/d from January 2021. We forecast that global consumption of petroleum and liquid fuels will average 100.6 million b/d for all of 2022, which is up 3.5 million b/d from 2021 and more than the 2019 average of 100.3 million b/d. We forecast that global consumption of petroleum and liquid fuels will increase by 1.9 million b/d in 2023.

- U.S. regular gasoline retail prices averaged $3.31 per gallon (gal) in January, unchanged from December 2021 and up 98 cents/gal from January 2021. Retail diesel prices averaged $3.72/gal in January, up 8 cents/gal from December and up $1.04/gal from last January. Product prices have risen compared with year-ago levels because of rising crude oil prices and high refining margins. We expect diesel prices will average $3.49/gal from 2Q22 through 4Q22. The forecast decline in prices reflects our expectation of falling crude oil prices, particularly in the second half of 2022 (2H22), as well as lower refining margins as refineries increase throughputs in the coming months.

- U.S. crude oil production reached almost 11.8 million b/d in November 2021 (the most recent monthly historical data point), the most in any month since April 2020. We forecast that production will rise to an average of 12.0 million b/d in 2022 and 12.6 million b/d in 2023, which would be record-high production on an annual-average basis. The previous annual average record of 12.3 million b/d was set in 2019.

### Natural Gas

- In January, the natural gas spot price at Henry Hub averaged $4.38 per million British thermal units (MMBtu), up from the December average of $3.76/MMBtu. Higher prices in January were a result of colder-than-normal weather in parts of the country, particularly the Northeast and the Midwest where demand increased for natural gas used for space heating and for power generation. STEO uses weather forecasts from the National Oceanic and Atmospheric Administration (NOAA), and NOAA published the forecast we used in this STEO in late January. Temperatures have continued to be cold in parts of the country in early February, which we expect will contribute to Henry Hub prices averaging $4.70/MMBtu for the month. The winter weather forecasts are highly variable and create a significant amount of uncertainty in our price forecast. In addition, global demand for U.S. liquefied natural gas (LNG) has remained high, limiting some of the downward pressure on natural gas prices. We expect natural gas prices could remain volatile over the coming months, and the way that temperatures affect natural gas demand in February and March will be a key driver of how inventories end the
withdrawal season, which will be important for natural gas price formation in the coming months.

- We estimate that U.S. LNG exports averaged 11.2 billion cubic feet per day (Bcf/d) in January 2022, up from 10.4 Bcf/d in 4Q21, supported by large price differences between the Henry Hub price in the United States and spot prices in Europe and Asia. In particular, inventories in Europe remain much lower than their five-year averages and are contributing to strong demand for LNG imports. We expect high levels of U.S. LNG exports to continue into 2022, averaging 11.3 Bcf/d for the year, a 16% increase from 2021. The forecast reflects our assumptions that global natural gas demand remains strong and that expected additional U.S. LNG export capacity comes online.

- Colder-than-normal temperatures in January resulted in U.S. natural gas inventories falling below the five-year average to end the month at 2.3 trillion cubic feet (Tcf). We expect natural gas inventories to fall by about 730 Bcf for the rest of the withdrawal season, ending March just below 1.6 Tcf, which would be 8% less than the 2017–21 average for that time of year.

- We expect U.S. consumption of natural gas will average 105.2 billion cubic feet per day (Bcf/d) in February, down 3% from February 2021. Consumption in our forecast declines the most in the residential and commercial sectors, where consumption will average a combined 43.8 Bcf/d, down 10% from last February. We forecast electric power section consumption will be 27.8 Bcf/d in February, down 1% from last February. The changes are partly offset by industrial sector consumption, which grows by 4% from February 2021 in the forecast to average 24.8 Bcf/d for the month.

- We estimate dry U.S. natural gas production averaged 95.5 Bcf/d in the United States in January, down 2.1 Bcf/d from December 2021. Production in January was lower due, in some part, to freezing temperatures in certain production regions. We forecast natural gas production to average 95.6 Bcf/d in February and 96.1 Bcf/d for all of 2022, driven by natural gas and crude oil price levels that we expect will be sufficient to support enough drilling to sustain production growth. We expect production to rise to an average of 98.0 Bcf/d in 2023.

**Electricity, coal, renewables, and emissions**

- We forecast that the share of U.S. electric power sector generation produced by natural gas will average 35% in 2022 and 2023, down from 37% in 2021. The estimated cost of natural gas delivered to power generators averaged $4.97/MMBtu in 2021, and we expect it to fall to $4.16/MMBtu in 2022 and $3.86/MMBtu in 2023. Despite the forecast decline in fuel costs, the share of electricity generation from natural gas declines in the forecast because of growth in renewable generation. We expect the renewable generation share to increase from 20% in 2021 to 22% in 2022 and 24% in
2023. Increasing renewable generation contributes to our forecast that the share of
generation from coal will decline from 23% in 2021 to an average of 22% over the next
two years. Forecast generation from nuclear remains relatively constant through the
forecast at an average generation share of 20%.

- We expect U.S. coal production to increase by almost 28 million short tons (MMst) (5%) in
  2022 to 606 MMst and then rise by 18 MMst (3%) in 2023. Producers in the Powder
  River Basin have increased employment at mines in recent months to boost production
to meet domestic demand, but we expect tight supply conditions to remain through the
remainder of the year. We expect U.S. coal consumption to decrease by 2 MMst in 2022
as a 5 MMst (1%) decline in consumption from the electric power sector is somewhat
offset by a 2 MMst (14%) increase in consumption for coke plants. Exports are expected
to increase by 3 MMst (4%) in 2022 because international prices continue to be high for
U.S. coal.

- Planned additions to U.S. wind and solar capacity in 2022 and 2023 increase electricity
generation from those sources in our forecast. We estimate that the U.S. electric power
sector added 16.3 gigawatts (GW) of new wind capacity in 2021. We expect 7.6 GW of
new wind capacity will come online in 2022 and 4.3 GW in 2023. Utility-scale solar
capacity rose by an estimated 13.9 GW in 2021. Our forecast for added utility-scale solar
capacity is 21.8 GW for 2022 and 24.1 GW for 2023. We expect solar additions to
account for nearly half of new electric generating capacity in 2022. In addition, in 2021,
small-scale solar capacity (from systems less than 1 megawatt) increased by 5.1 GW to
32.7 GW. We project that small-scale solar will grow by 4.4 GW per year in both 2022
and 2023.

- U.S. energy-related carbon dioxide (CO₂) emissions increased by more than 6% in 2021
as economic activity increased and contributed to rising energy use. We expect a 2%
increase in energy-related CO₂ emissions in 2022, primarily from growing
transportation-related petroleum consumption. Forecast energy-related CO₂ emissions
remain almost unchanged in 2023. We expect petroleum emissions to increase by 4% in
2022, and this growth rate slows to less than 1% in 2023. Natural gas emissions increase
by 2% in 2022 and then decrease slightly in our forecast for 2023. We forecast that coal-
related CO₂ emissions will decline by 1% in 2022 and by 2% in 2023.
Petroleum and natural gas markets review

Crude oil

**Prices:** The front-month futures price for Brent crude oil settled at $91.11 per barrel (b) on February 3, 2022, an increase of $12.13/b from the January 3, 2022, price of $78.98/b. The front-month futures price for West Texas Intermediate (WTI) crude oil for delivery at Cushing, Oklahoma, increased by $14.19/b during the same period, settling at $90.27/b on February 3 (Figure 1).

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

Source: Graph by EIA, based on CME Group and Intercontinental Exchange, as compiled by Bloomberg L.P.

Brent crude oil prices increased throughout January as persistent global oil inventory draws and geopolitical tensions contributed to market concerns about disruptions to oil production. On several days in late-January and early February the nominal (not adjusted for inflation) front-month Brent price reached more than $90/b for the first time since October 2014. Global oil consumption has exceeded global oil supply since mid-2020, leading to six consecutive quarters of global oil inventory draws. We estimate global oil inventories declined again in January, contributing to commercially held inventories in OECD countries reaching the lowest levels since mid-2014. A major contributing factor to the low global oil inventories is some OPEC+ countries producing less than their targeted amounts due to operational difficulties ramping up production. During 4Q21, we estimate that the 10 OPEC countries subject to production targets produced less than those targets by a combined average of more than 0.6 million barrels per day (b/d).

More recently, geopolitical conflicts have also put upward pressure on oil prices. Prices can be more sensitive to concerns about supply disruptions during periods of low inventories. Tensions related to Ukraine have increased market concerns about the possibility of oil supply disruptions. In the Middle East, several missile attacks on Abu Dhabi—one of which hit a fuel
storage facility—has added to uncertainties for future oil supply, which may also be affected by political unrest in Libya and Kazakhstan. Libya’s oil production has increased following blockades that shut in crude oil production in late December and early January, and production in Kazakhstan has increased following disruptions that occurred during protests from January 2–January 11 related to higher liquefied petroleum gas prices. Concerns about low oil inventories and potential supply disruptions have outweighed downward price pressure from China’s announcement that it will release crude oil from its national strategic stockpiles.

Although the front-month Brent crude oil price reached more than $90/b at times in late-January, longer-dated contracts did not increase as much. This wide backwardation (when near-month prices are higher than longer-dated ones) suggests market participants are paying higher prices to secure oil from available inventories amid the large imbalance between supply and demand. The five-day moving average of the spread between prices for the 1st month futures contract and the 13th month contract for Brent widened to $10.46/b on February 3, from $5.62/b on January 3, and the spread between the 1st month futures contract and 13th month contract for WTI was even higher at $11.88/b on February 3, an increase from $6.45/b on January 3 (Figure 2).

![Figure 2. Crude oil front-month to 13th month futures price spread](image)

We forecast global inventory draws in February, with an average Brent spot price of $90/b. However, we expect oil inventories will begin rebuilding in March and continue throughout the forecast, which will result in lower crude oil prices. We forecast the Brent crude oil price to decrease to an average of $87/b in 2Q22 and $75/by 4Q22. We expect the Brent spot price to average $68/b in 2023. We estimate that OECD commercial inventories in January 2022 were 270 million barrels (9%) below their five-year (2017–2021) January average and that absolute inventory levels were at their lowest level since 2014 (Figure 3). We forecast OECD commercial inventories will increase to their five-year average by mid-2023. Although we expect inventories to rise, the low inventory levels in recent months will likely limit downward price pressure for
much of the first half of 2022 (1H22). In addition, until inventories move closer to five-year average levels, the potential for a supply disruption to significantly affect price levels and volatility is greater. Inventory growth in the forecast is driven by rising global oil production, largely from OPEC+ and the United States, along with slowing growth in global oil consumption. Our expectation of falling oil prices, particularly beyond 1H22, is contingent on our forecast of oil production and inventory growth. However, oil production might not meet our expectations because of possible changes in production targets from OPEC+, continuing technical issues among some producers, and changes in the investment decisions of U.S. tight oil operators, among other possible reasons.

**Figure 3. OECD commercial liquid inventories minus five-year average and Brent price**

![Graph showing OECD commercial liquid inventories minus five-year average and Brent price](image)

**Market-derived probabilities:** Crude oil prices continue to be subject to high levels of uncertainty due to COVID-19-related end-user behavior, geopolitical factors, and other disruptions to global oil supply and demand. Market-derived price probabilities that are based on futures and options prices reflect this price uncertainty. As of February 3, the probability of the June 2022 WTI contract expiring at more than $90/b was 34% (Figure 4). Furthermore, market participants increased trading in call options with strike prices of $100/b throughout much of January. A call option is a financial instrument that gives the owner the right, but not the obligation, to purchase WTI futures at a certain price by an expiration date. Call options increase in value when the WTI futures price increases. The market-derived probability of $100/b WTI for the June contract increased from 8% on January 3 to 19% on February 3. Open interest for June WTI call options with a strike price of $100/b increased from 18,079 contracts on January 3 to 23,911 contracts on February 3. Trading volume increased from an average of 862 contracts per day in the first half of the month (January 3–January 14) to an average of 1,544 contracts per day in the second half of the month (January 17–January 31). Although the market-derived price probability of $100/b WTI crude oil has increased, the probability of it expiring at less than $70/b is slightly higher, at 25%. These large differences in market-derived probabilities reflect the significant uncertainty and high volatility in the oil market.
Typically, the correlation between equity prices and crude oil prices are highest when demand-side factors, such as global economic growth, are driving crude oil prices. In recent weeks, the correlation between daily price changes in the S&P 500, an equity index of widely traded U.S. public companies, and Brent crude oil has decreased from a multiyear high reached on January 4. Since January 2017, the rolling 30-day correlation between the S&P 500 and Brent crude oil has been higher than 0.75 on two occasions (Figure 5). The first occasion was in July 2020, when both the S&P 500 and the Brent crude oil price were increasing from their low points following the onset of the COVID-19 pandemic. The second occasion was in December 2021 and early January 2022, when equities, oil, and many other commodities were beginning to return to normal levels following a demand shock that began on November 26 when the World Health Organization designated the SARS-CoV-2 Omicron variant as a concern.
The correlation between the S&P 500 and Brent crude oil has been steeply decreasing since mid-January as concerns about the Omicron variant have lessened and factors more specific to the oil market have caused trends in crude oil prices to deviate from those of the S&P 500. Although the stock market and S&P 500 have been generally decreasing in reaction to changing expectations that the Federal Reserve may increase interest rates in 2022 more than previously expected, low oil inventories and the possibility that geopolitical issues could affect crude oil supply have been driving crude oil prices higher. As of February 3, the rolling 30-day correlation between the two was 0.11, the lowest it has been since the November 26 Omicron announcement.

**U.S. production by region:** After averaging 7.7 million b/d in the first half of 2021, according to our Drilling Productivity Report, U.S. crude oil production in all major shale regions increased to 8.2 million b/d in the second half of the year, largely because of rising production in the Permian Basin. Increases in well completions and rig counts in the Permian Basin have led to record production in that area, with forecasted oil production in the Permian Basin exceeding 5.0 million b/d for February 2022 (Figure 6). The region’s favorable geology combined with technological and operational improvements have supported the record production levels. In contrast to the record production in the Permian Basin, we expect production in other shale basins to average almost 3.5 million b/d in February, which is nearly 1.1 million b/d less than the record for production in these regions set in October 2019. The lack of growth and recovery in these other regions reflects more investments flowing to the Permian Basin than to other basins. According to Baker Hughes rig counts, from January 29, 2021, to January 28, 2022, the number of oil-directed rigs in the Permian Basin increased from 192 to 293. In the entire United States, the oil-directed rig count had increased by 200 during that period, meaning rig count growth in the Permian Basin accounts for more than half of the U.S. total.
Petroleum products

Gasoline prices: The front-month futures price of RBOB (the petroleum component of gasoline used in many parts of the country) settled at $2.64 per gallon (gal) on February 3, up 39 cents/gal from January 3 (Figure 7). The RBOB–Brent crack spread (the difference between the price of RBOB and the price of Brent crude oil) settled at 47 cents/gal on February 3, up 10 cents/gal from the start of January. The average RBOB–Brent crack spread in January was 37 cents/gal, 1 cent/gal higher than the average spread in December.

The RBOB–Brent crack spread remains wider than the five-year average for this time of year, continuing a trend of above-average crack spreads since January 2021. Since August, every
month was a record crack spread for that month in data going back to 2008. January’s crack spread is more than double the five-year average. Rising crude oil prices and relatively low gasoline production contributed to higher front-month RBOB prices. Rapidly increasing crude oil prices typically reduce product crack spreads, but lower-than-average inventories are supporting these higher crack spreads.

**March to April RBOB contract spread:** The RBOB futures contract for April delivery is the first contract during the year that trades summer-grade gasoline, which is more expensive to produce and typically trades at higher prices than winter-grade gasoline. As a result, April contracts trade at a premium to March contracts. The 2016–2020 average spread during January trading between RBOB contracts for April delivery and RBOB contracts for March delivery was 19 cents/gal (Figure 8). This year the spread was 11 cents/gal, similar to the spread last year and only 1 cent/gal higher than the lowest spread recorded, which occurred in 2010. The relatively low spread could indicate new streamlining rules for testing summer-grade gasoline that the U.S. Environmental Protection Agency rolled out last year to make it easier to transition from winter to summer specifications has led to lower RBOB prices for summer-grade gasoline.

![Figure 8. RBOB April minus March contract spread](image)

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Source: Graph by EIA, data from CME Group, as compiled by Bloomberg L.P.
Note: RBOB-refined blendstock for oxygenate blending

**Ultra-low sulfur diesel prices:** The front-month futures price for ultra-low sulfur diesel (ULSD) for delivery in New York Harbor settled at $2.84/gal on February 3, a 48 cents/gal increase from January 3 (Figure 9). The ULSD-Brent crack spread (the difference between the price of ULSD and the price of Brent crude oil) increased 19 cents/gal during the same period and settled at 67 cents/gal on February 3.
The ULSD–Brent crack spread in January averaged 57 cents/gal, up 10 cents/gal from December 2021 and up 31 cents/gal from January 2021. Rising crude oil prices throughout January contributed to the increase in outright ULSD prices, while seasonal demand for heating oil in the U.S. Northeast and mid-Atlantic regions related to cold temperatures contributed to more demand for distillate fuel oil. Lower ULSD inventories and the increasing ULSD crack spread may result from less refinery production and potential reductions in distillate yields to increase jet fuel production compared with December.

We estimate U.S. distillate consumption in January was 4.4 million b/d in January, an increase of 0.3 million b/d from December 2021, and 0.4 million b/d more than January 2021. Although more than last year, distillate consumption is at a similar level to January 2019 and is less than January 2018. We expect distillate consumption to decrease in the coming months as the weather becomes milder. Distillate inventories ended January at 123 million barrels, 19% below the five-year average. We expect continued draws on distillate inventories until June as low refinery production during turnaround season constrains production while demand for road diesel persists. Low distillate inventories, combined with high crude oil prices will contribute to higher ULSD prices, and we expect wholesale ULSD prices to remain above $2/gal through the rest of 2022 and 2023.

The increase in U.S. distillate consumption in January was driven by colder weather. We measure the effects of winter weather on energy markets by analyzing heating degree days (HDDs). The more HDDs, the colder the weather. In New England (PADD 1A) and the mid-Atlantic (PADD 1B), heating oil remains a substantial source in the energy mix in the residential home-heating sector, unlike much of the United States where home heating is primarily provided by natural gas or electricity. December 2021 temperatures in New England and the mid-Atlantic were relatively mild compared with previous seasons, and HDDs totaled 1,722 for the month, which was fewer than the past three winters and 186 HDDs fewer than the 10-year
average (Figure 10). January weather was cold, and HDDs increased to 2,485 HDDs, 204 HDDs more than the 10-year average. We forecast warmer weather in the coming months will lead to fewer HDDs and, as a result, less home heating oil consumption in the Northeast and mid-Atlantic.

![Figure 10. U.S. Northeast (PADD 1A+1B) Heating Degree Days](image)

**ULSD front 13th month spread:** The spread between the front-month and the 13th month price for ULSD futures is a measure of the value of ULSD delivered in the near term compared with ULSD for delivery one year in the future. A large price spread typically indicates a market in which demand exceeds supply, leading to draws on inventories. The spread climbed rapidly in January, reaching its widest level since 2014, at 35 cents/gal as of February 3 (Figure 11). The wide spread is related to distillate inventories that were 19% below the five-year (2017–2021) average for the week ending January 28, according to our *Weekly Petroleum Status Report*. The wide spread between the front-month and the 13th month contracts for crude oil is a contributing factor to the wide ULSD spread for the same contracts. Typically, the spread for ULSD is narrower than the spread for crude oil, however in January 2022, the spread for ULSD exceeded Brent crude oil by an average of 4 cents. The substantial role of seasonally related weather demand is an important element of the current high prices, and we expect that U.S. distillate consumption will decline in the coming months while refinery production of distillate will increase.
Natural Gas

Prices: The front-month natural gas futures contract for delivery at the Henry Hub settled at $4.89 per million British thermal units (MMBtu) on February 3, 2022, which was up $1.07/MMBtu from January 3, 2022 (Figure 12). The average closing price for front-month natural gas futures contracts in January was $4.26/MMBtu, the highest January monthly average in real terms since January 2014.

The average price for front-month natural gas futures contracts in January was 40 cents higher than the December average closing price of $3.86/MMBtu. January was colder than December, which resulted in greater use of natural gas for space heating in the residential and commercial sectors. December 2021 was much warmer than normal, and natural gas withdrawals from...
storage were below the five-year average (2016–2020), which contributed to lower natural gas prices throughout the month. In January, colder-than-normal temperatures resulted in storage withdrawals that exceeded the five-year average (2017–2021) by 219 Bcf in order to meet the demand for both space heating and electric power burn. We forecast that combined demand in the residential and commercial sectors in January averaged 48.4 Bcf/d, which is 14.5 Bcf/d more than December 2021 and 3.0 Bcf/d more than the January five-year average.

Record U.S. liquefied natural gas (LNG) exports, increased power demand, and a decline in January natural gas production all contributed to above-average storage withdrawals in January, putting upward pressure on prices. In January, U.S. LNG exporters continued to operate at maximum capacity, resulting in exports above 11 Bcf/d for the second consecutive month. We estimate LNG exports averaged 11.2 Bcf/d in January as the new Train 6 at Sabine Pass LNG continues to ramp up production. Continued strong demand for LNG imports in Europe and Asia supports facilities operating at maximum capacity. In addition to more LNG exports, we estimate that demand for natural gas used to generate electric power averaged 31.0 Bcf/d in January, 2.9 Bcf/d more than last year. Lastly, we estimate that U.S. dry natural gas production declined in January, averaging 95.5 Bcf, 2.1 Bcf/d less than December. Cold temperatures and freeze-offs in certain producing areas likely contributed to the decline in production.

The cold weather particularly affected New England, where well-below-normal temperatures led to increased natural gas consumption in the region. In addition, natural gas pipeline supply into New England is constrained, particularly during peak demand periods in the winter. Due to strong demand for natural gas this winter, the spot price at the Algonquin Citygate—a benchmark hub for the natural gas price in New England—exceeded $20/MMBtu on several days (Figure 13) and averaged $20.55/MMBtu in January—the highest monthly average price since February 2014. In the past three winters, the monthly average spot price at Algonquin Citygate traded between $3/MMBtu and $6/MMBtu, and the daily price never exceeded $14/MMBtu for any of the three winters. In contrast to the high prices this winter in the Northeast, the daily spot price at Henry Hub averaged $4.38/MMBtu in January.
Notable forecast changes

- We forecast the Brent crude oil spot price will average $83/b in 2022, which is $8/b more than we forecast in the January STEO. The higher price forecast partly reflects a reduction in our forecast of OECD inventories in 1H22. Although we continue to expect crude oil prices to decline beginning in March, crude oil price increases over the past month mean that declines will begin from a higher price level, which also contributes to higher crude oil price levels in our forecast throughout 2022. The increase in crude oil prices in the forecast also results in higher prices for gasoline and diesel fuel in 2022 compared with last month’s forecast. It also results in more U.S. crude oil production compared with last month’s forecast.

- Based on data from the Federal Highway Administration, we updated and released historical data for vehicle miles traveled in the STEO. The latest data reflect more vehicle miles traveled in 2021 than previously reported, which increased our estimates of vehicle efficiency. As a result, we increased our forecasts for vehicle miles traveled and vehicle efficiency. The revisions to vehicle efficiency, however, were more significant and drove our forecast gasoline consumption down in both 2022 and 2023. In 2022, we now forecast that gasoline consumption in the United States will average 8.9 million b/d, down from 9.1 million b/d in the January STEO. In our February STEO, we forecast that gasoline consumption in 2023 will average 9.0 million b/d, down from a forecast of 9.1 million b/d in the January STEO.

- Beginning with this STEO, we will provide new forecasts for biodiesel, renewable diesel, and other biofuels, which includes fuels such as renewable jet fuel and renewable naphtha. In our custom table builder, we will provide production, consumption, and net imports for each of these fuels. The changes reflect the inclusion of these series in Table
10.4 of the *Monthly Energy Review* (MER) beginning in mid-2021. Related to this change, we have added a line for consumption (product supplied) of other hydrocarbons and oxygenates in Table 4a of STEO. *Product supplied of other hydrocarbons and oxygenates* is a category that includes biodiesel, renewable diesel, and other biofuels, which in the *Petroleum Supply Monthly* (PSM) are collectively called *renewable fuels excluding fuel ethanol*. In the PSM, product supplied of renewable fuels excluding fuel ethanol plus refinery and blender net inputs of renewable fuels excluding fuel ethanol is equal to the consumption of biodiesel, renewable diesel, and other biofuels as reported in MER.

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