Energy Tidbits

Bullish for Oil & Natural Gas for 2020s, China Says "Supply Shortage is The Biggest Energy Insecurity"

Produced by Dan Tsubouchi

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Dan Tsubouchi
Principal, Chief Market Strategist
dtsubouchi@safgroup.ca

Ryan Dunfield
Principal, CEO
rdunfield@safgroup.ca

Aaron Bunting
Principal, COO, CFO
abunting@safgroup.ca

Ryan Haughn
Principal, Energy
rhaughn@safgroup.ca

https://www.climate.gov/news-features/featured-images/how-el-ni%C3%B1o-and-la-ni%C3%B1a-affect-winter-jet-stream-and-us-climate

How El Niño and La Niña affect the winter jet stream and U.S. climate

BY REBECCA LINDSEY REVIEWED BY TOM DI LIBERTO
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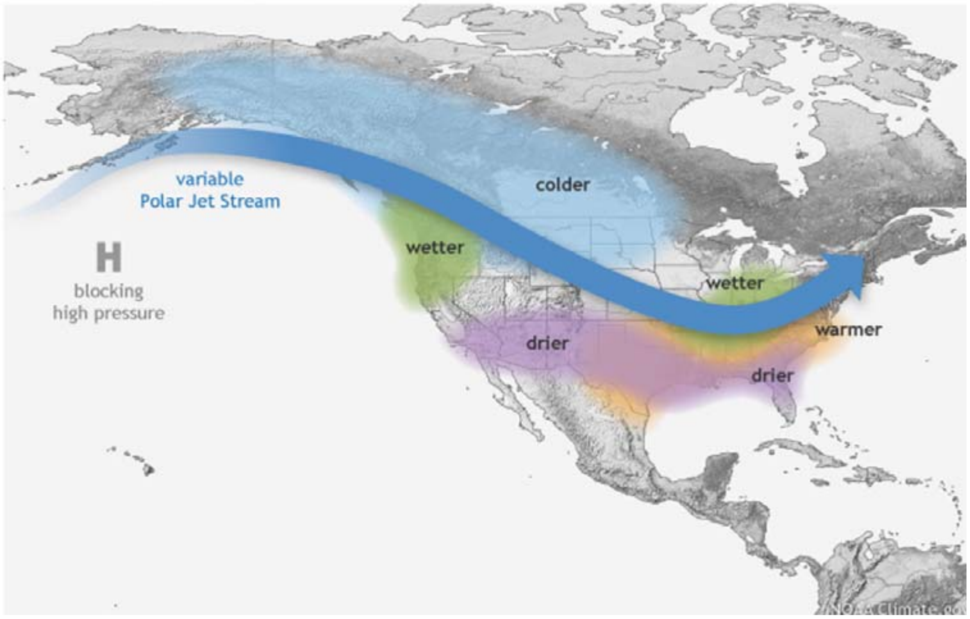
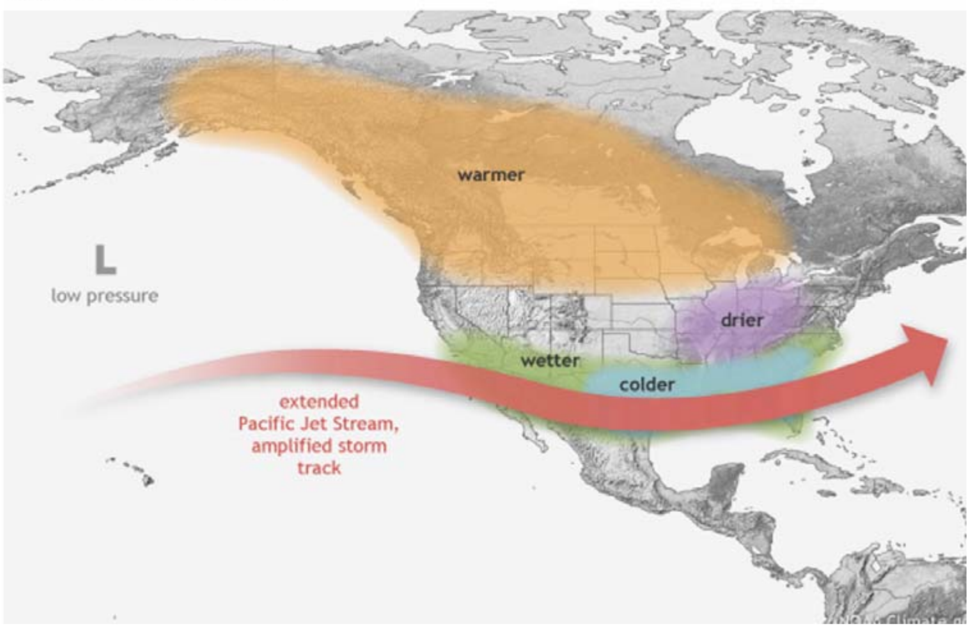
WINTER LA NIÑA PATTERN



WINTER EL NIÑO PATTERN



DETAILS

The arrival of El Niño or La Niña in the tropical Pacific Ocean triggers a cascade of changes in tropical rainfall and wind patterns that echo around the globe. For the United States, the most significant impact is a shift in the path of the mid-latitude jet streams. These swift, high-level winds play a major role in separating warm and cool air masses and steering storms from the Pacific across the U.S.

These maps illustrate the typical impacts of El Niño and La Niña on U.S. winter weather. During La Niña, the Pacific jet stream often meanders high into the North Pacific and and is less reliable across the southern tier of the United States. Southern and interior Alaska and the Pacific Northwest tend to be cooler and wetter than average, and the southern tier of U.S. states—from California to the Carolinas—tends to be warmer and drier than average. Farther north, the Ohio and Upper Mississippi River Valleys may be wetter than usual. During El Niño, these deviations from the average are approximately (but not exactly) reversed.

One or more of these climate patterns have occurred during many El Niño and La Niña events in the past. That doesn't mean that **all** of these impacts happen during **every** episode. Every event is somewhat different. In other words, the influence of El Niño on U.S. winter climate is a matter of *probability*, not certainty.

El Niño and La Niña are opposite phases of a natural climate pattern across the tropical Pacific Ocean that swings back and forth every 3-7 years on average. El Niño and La Niña alternately warm and cool large areas of the tropical Pacific—the world's largest ocean—which significantly influences where and how much it rains there.

Like a boulder dropped into a stream, this shift in the location of tropical rainfall disrupts the atmospheric circulation patterns that connect the tropics with the middle latitudes, which in turn modifies the mid-latitude jet streams. By modifying the jet streams, El Niño and La Niña can affect temperature and precipitation across the United States and other parts of the world. The influence on the U.S. is strongest during the winter (December-February), but it may linger into early spring.

Findings

- Winter energy expenditures are likely to be higher than previous winter across all fuels and all regions, which mostly reflects higher retail prices

- U.S. retail energy prices are starting the winter at multi-year highs

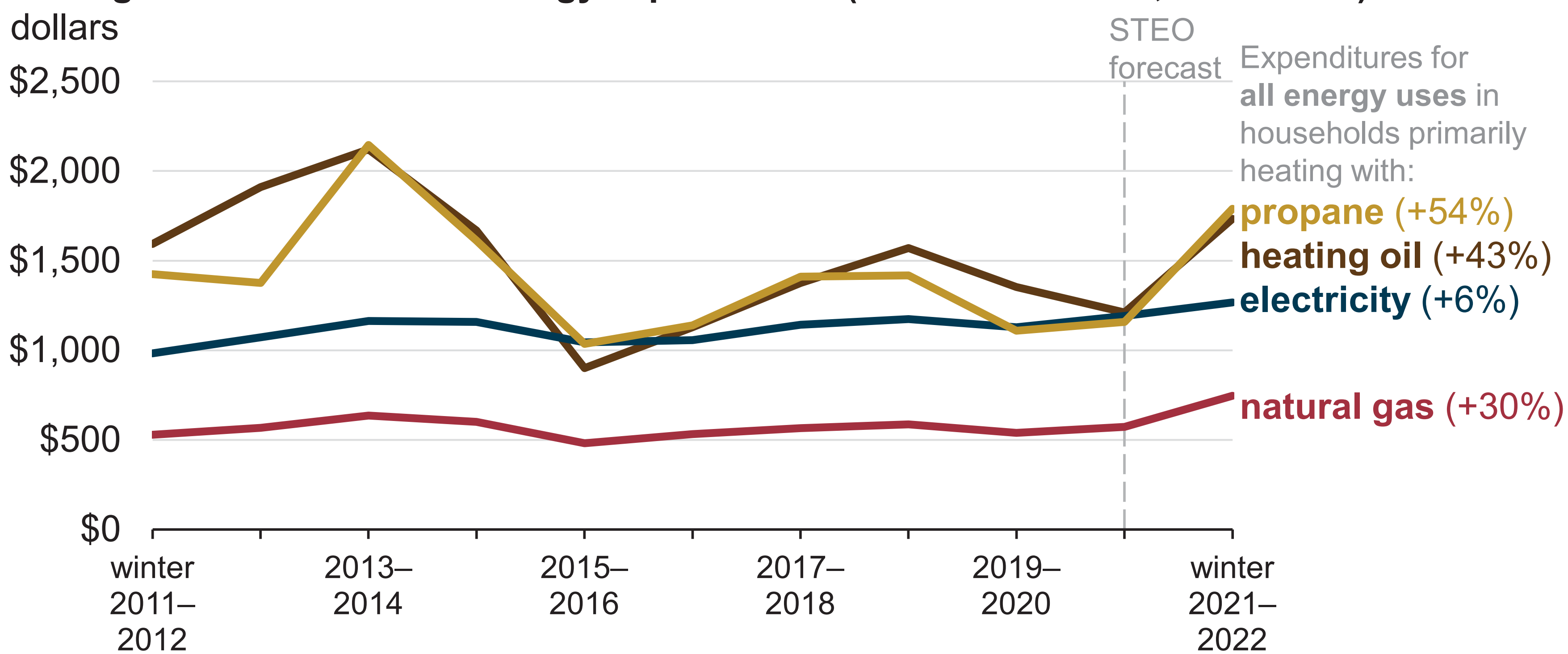
- Winter temperatures are currently forecast to be slightly colder than previous winter

- Propane and natural gas inventories—which are already lower than normal—could fall to record lows, especially in a colder weather scenario

- High fuel prices in global markets provide incentive to continue exporting propane and natural gas

We expect energy expenditures to increase for all heating fuels, primarily driven by higher prices

Average winter household energy expenditures (winter = Oct–Mar, 2011–2022)



Note: Propane price reflects the average of Northeast and Midwest regions through winter 2013–14 and average of Northeast, Midwest, and South regions after winter 2013–14.

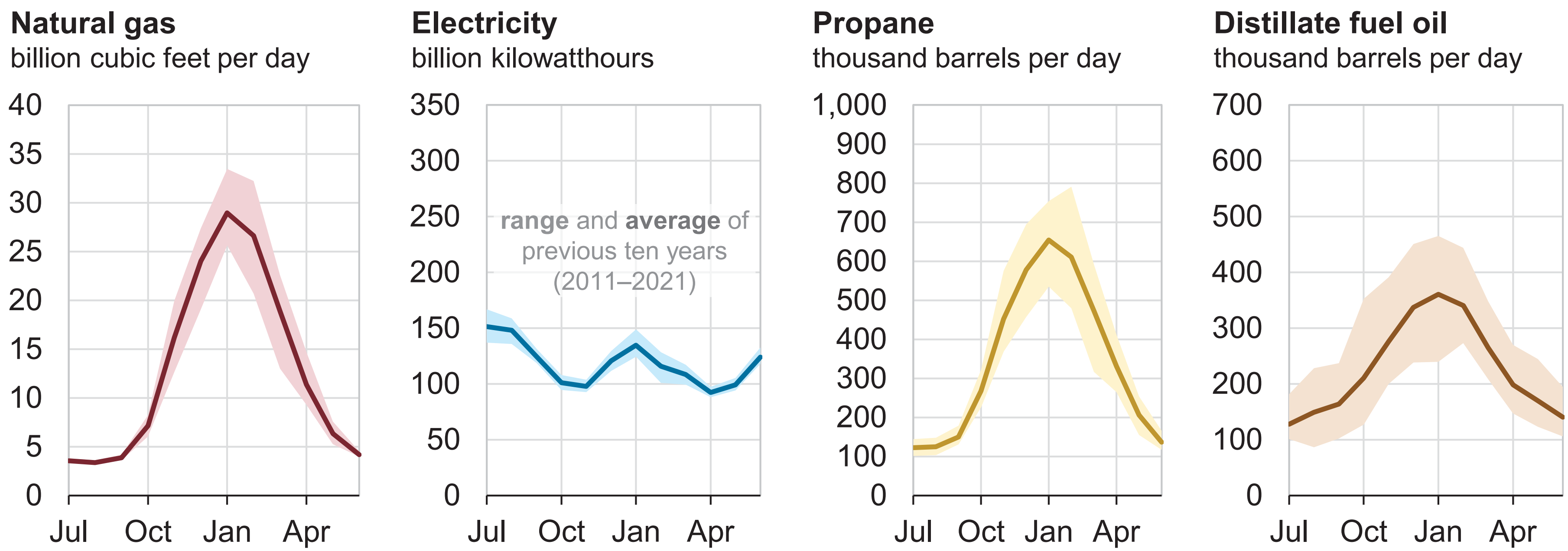
Source: U.S. Energy Information Administration

Because of higher prices in the forecast, even in a warmer than forecast scenario, expenditures are up from last winter

	U.S. average household expenditures Base Case (Oct–Mar total)		U.S. average household expenditures 10% Colder (Oct–Mar total)		U.S. average household expenditures 10% Warmer (Oct–Mar total)	
	winter 2021–22	Change from last winter	winter 2021–22	Change from last winter	winter 2021–22	Change from last winter
Natural Gas	$746	+30%	$859	+50%	$700	+22%
Heating Oil	$1734	+43%	$1925	+59%	$1573	+30%
Electricity	$1268	+6%	$1370	+15%	$1237	+4%
Propane	$1789	+54%	$2246	+94%	$1497	+29%

Source: U.S. Energy Information Administration

For most fuels, residential consumption is concentrated in winter



The winter months of October through March account for **79%** of annual residential **natural gas** consumption…

…**48%** of annual residential **electricity** consumption…

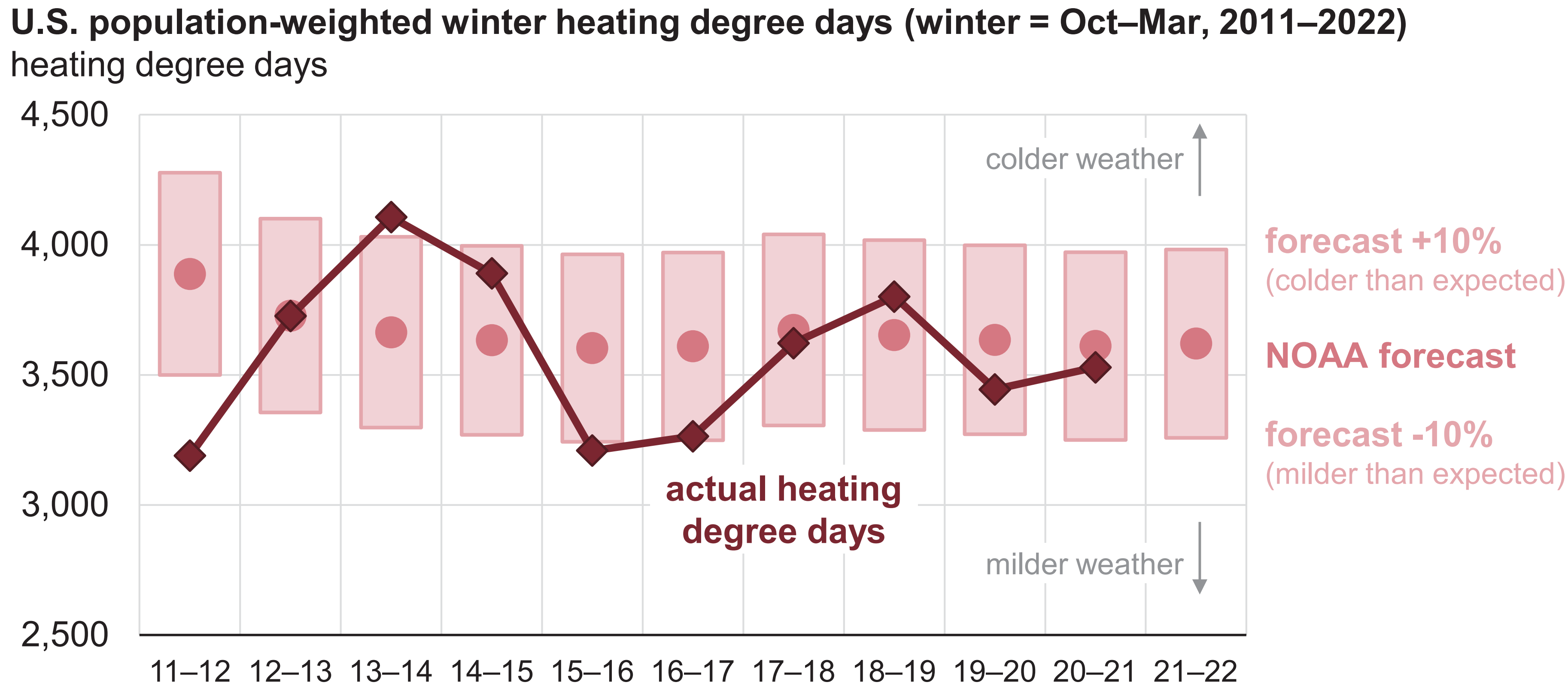
…**74%** of annual residential **propane** consumption…

…and **65%** of annual residential **distillate fuel oil** consumption.

Note: Reflects consumption in all households, not just those using the fuel for primary space heating.

Source: U.S. Energy Information Administration, Monthly Energy Review

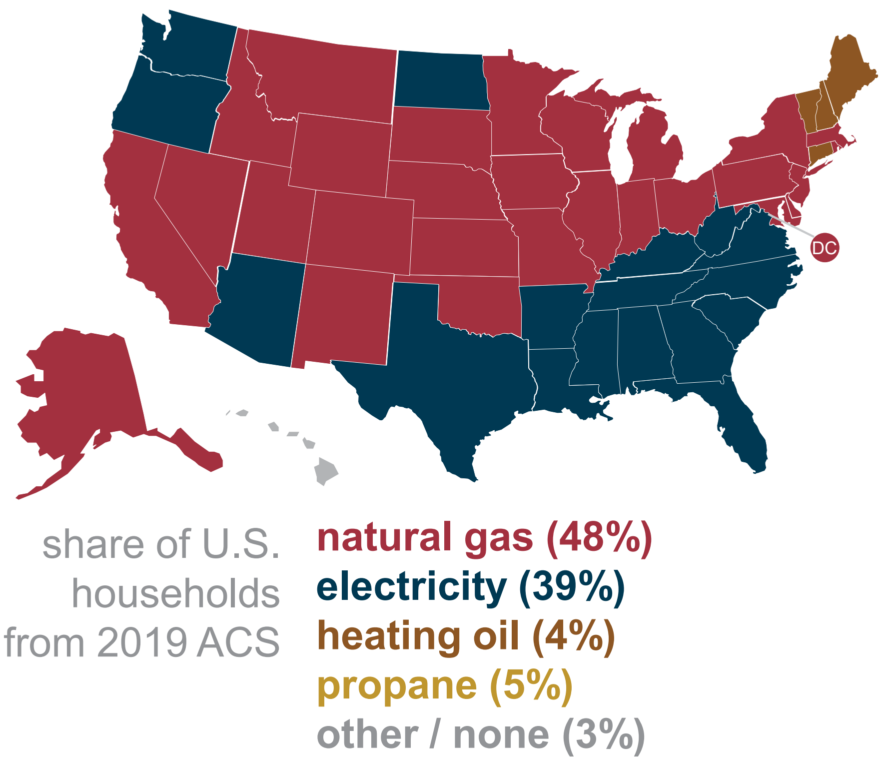
Actual heating degree days tend to be within 10% of the forecast



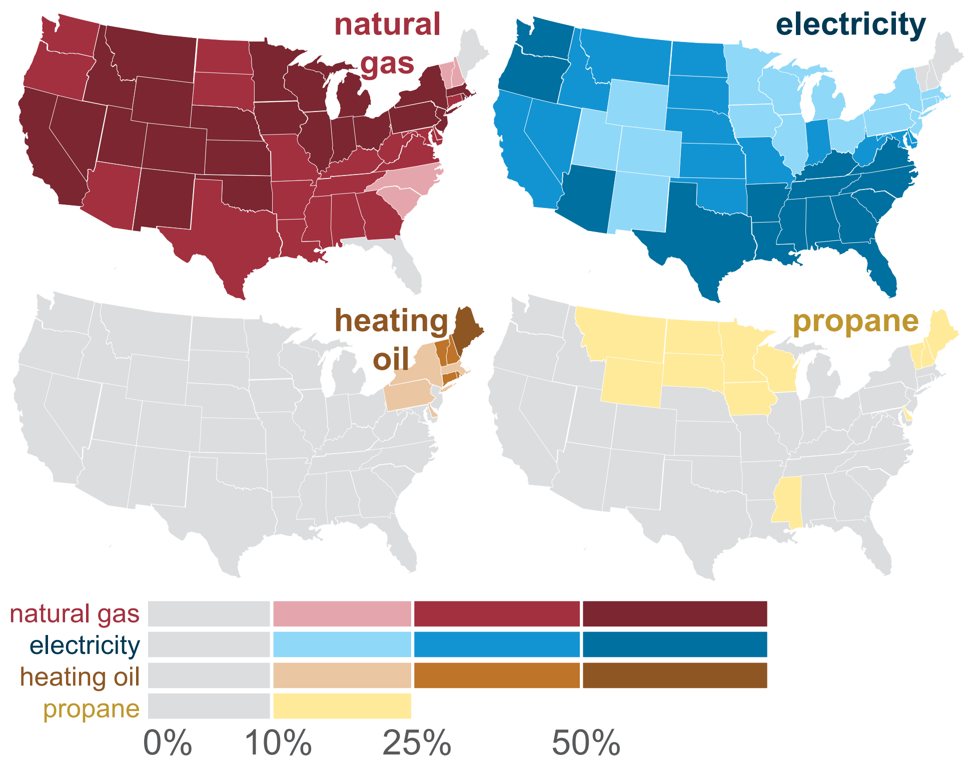
Source: U.S. Energy Information Administration based on data from NOAA

Almost 90% of U.S. homes are primarily heated by natural gas or electricity; heating oil and propane are regionally concentrated

Most prevalent home heating fuel by state (2019)

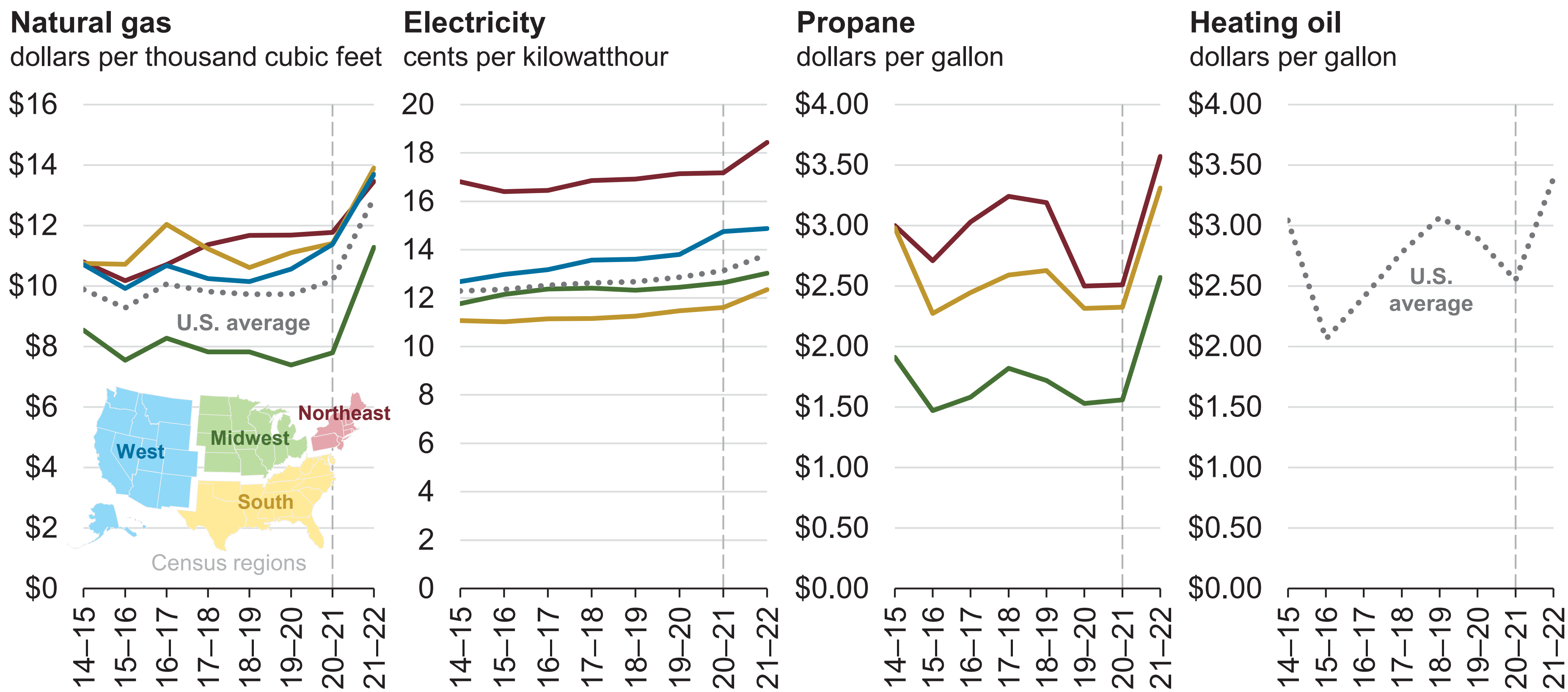


Primary home heating fuel by state (2019)



Source: U.S. Energy Information Administration based on data from the U.S. Census Bureau, American Community Survey 2019

Prices across all fuels and all regions in the forecast are higher compared with recent winters



Source: U.S. Energy Information Administration

Natural gas summary

	Households primarily heating with natural gas		Average household Consumption (million cubic feet)		Average household Retail price ($ / million cubic feet)		Average household Expenditures (Oct–Mar total)	
	thousands	fuel share of region	winter 2021–22	change	winter 2021–22	Change	winter 2021–22	Change
Northeast	12.7	57%	64	+3%	$13.46	+14%	$865	+18%
Midwest	18.1	64%	73	+3%	$11.28	+45%	$818	+48%
South	14.4	29%	45	0	$13.90	+22%	$623	+22%
West	15.6	54%	48	+3%	$13.69	+20%	$654	+24%
U.S. total	60.8	47%	58	+2%	$12.92	+27%	$746	+30%

Source: U.S. Energy Information Administration

Short-Term Energy Outlook

Forecast highlights

Winter Fuels Outlook

- We forecast that average U.S. household expenditures for all major home heating fuels will increase significantly this winter primarily because of higher expected fuel costs as well as more consumption of energy due to a colder winter. Average increases vary by fuel, region, and weather assumptions. Compared with last winter, we forecast propane expenditures will rise by 54%, heating oil by 43%, natural gas by 30%, and electricity by 6%. We expect space heating demand to generally be higher this winter based on forecasts from the National Oceanic and Atmospheric Administration (NOAA) that U.S. average heating degree days will be 3% higher than last winter (*Winter Fuels Outlook*). Altering our assumptions for a 10% colder-than-expected winter significantly increases forecast expenditures, while a 10% warmer-than-expected winter still results in increased expenditures, because of price increases.

Global liquid fuels

- The October *Short-Term Energy Outlook* (STEO) remains subject to heightened levels of uncertainty related to the ongoing recovery from the COVID-19 pandemic. U.S. economic activity continues to rise after reaching multiyear lows in the second quarter of 2020 (2Q20). U.S. gross domestic product (GDP) declined by 3.4% in 2020 from 2019 levels. This STEO assumes U.S. GDP will grow by 5.7% in 2021 and by 4.5% in 2022. The U.S. macroeconomic assumptions in this outlook are based on forecasts by IHS Markit. Our forecast assumes continuing economic growth and increasing mobility. Any developments that would cause deviations from these assumptions would likely cause energy consumption and prices to deviate from our forecast.

- Brent crude oil spot prices averaged $74 per barrel (b) in September, up $4/b from August and up $34/b from September 2020. Brent spot prices have risen from their September average to more than $80/b in early October. Oil prices have increased over the past year as result of steady draws on global oil inventories, which averaged 1.9 million barrels per day (b/d) during the first three quarters of 2021. In addition to sustained inventory draws, prices increased after the October 4 announcement by OPEC+ that the group would keep current production targets unchanged.

Note: EIA completed modeling and analysis for this report on Thursday October 7, 2021

- We expect Brent prices will remain near current levels for the remainder of 2021, averaging $81/b during the fourth quarter of 2021, which is $10/b higher than our previous forecast. The higher forecast reflects our expectation that global oil inventories will fall at a faster rate than we had previously expected owing largely to lower global oil supply in late 2021 across a range of producers. In 2022, we expect that growth in production from OPEC+, U.S. tight oil, and other non-OPEC countries will outpace slowing growth in global oil consumption and contribute to Brent prices declining from current levels to an annual average of $72/b.

- U.S. regular gasoline retail prices averaged $3.18 per gallon (gal) in September, up 2 cents/gal from August and almost $1/gal higher than in September 2020. Recent gasoline price increases reflect increasing crude oil prices outweighing falling gasoline wholesale margins. We forecast that retail gasoline prices will average $3.21/gal in October before falling to $3.05/gal in December.

- Total U.S. crude oil production averaged 11.3 million b/d in July —the most recent monthly historical data point. We estimate that domestic production fell to 10.6 million b/d in September because of disruptions from Hurricane Ida. We forecast production will be 11.0 million b/d in October and rise to 11.3 million b/d in December. We forecast 2021 production will average 11.0 million b/d, increasing to 11.7 million b/d in 2022 as tight oil production rises in the United States. Growth will come as a result of operators increasing rig counts, which we expect will offset production decline rates.

Natural Gas

- In September, the natural gas spot price at Henry Hub averaged $5.16 per million British thermal units (MMBtu), which was up from the August average of $4.07/MMBtu and up from an average of $3.25/MMBtu in the first half of 2021. The rising prices in recent months reflect U.S. natural gas inventory levels that are below the five-year average and continuing demand for natural gas for power generation use at relatively high prices.

- We expect the Henry Hub spot price will average $5.80/MMBtu in fourth-quarter 2021, which is $1.80/MMBtu higher than we forecast in the September STEO. In the current forecast, Henry Hub prices reach a monthly average peak of $5.90/MMBtu in January and generally decline through 2022, averaging $4.01/MMBtu for the year amid rising U.S. natural gas production and slowing growth in LNG exports. We raised our Henry Hub price forecast through the end of 2022 compared with last month. The increase reflects a higher starting point for our price forecast that incorporates recent developments in U.S. and global natural gas markets. We forecast that U.S. inventory draws will be slightly more than the five-year average this winter, and we expect that factor, along with rising U.S. natural gas exports and relatively flat production through January will keep U.S. natural gas prices near recent levels before downward pressures emerge. Given low natural gas inventories in both U.S. and European natural gas storage facilities and uncertainty around seasonal demand, we expect natural gas prices to remain volatile over the coming months, with winter temperatures being a key driver of demand and prices.

- We estimate that U.S. LNG exports averaged 9.3 billion cubic feet per day (Bcf/d) in September 2021, down 4% from August. Despite the recent monthly decline, these were the most U.S. LNG exports for September since the United States began exporting LNG from the Lower 48 states in February 2016. Even though September exports were a record for the month, they were limited by weather conditions, which led to the suspension of piloting services for several days at Sabine Pass, Cameron, and Corpus Christi. We expect that LNG exports will average 9.1 Bcf/d in October and then increase in the coming months. Cove Point LNG terminal is scheduled to complete its annual maintenance by mid-October and resume exports this month. Through this winter, LNG exports in the forecast average 10.7 Bcf/d as global natural gas demand remains high and several new LNG export trains—the sixth train at Sabine Pass LNG and the first trains at the new LNG export facility Calcasieu Pass LNG—enter service.

- We estimate that U.S. natural gas inventories ended September 2021 at about 3.3 trillion cubic feet (Tcf), 5% less than the five-year (2016–20) average for this time of year. Injections into storage this summer have been below the previous five-year average, largely as a result of more electricity consumption in June due to hot weather, and increased exports even as domestic natural gas production has remained flat. We forecast that inventories will end the 2021 injection season (at the end of October) at almost 3.6 Tcf, which would be 5% less than the previous five-year average. We expect natural gas inventories to fall by 2.1 Tcf this winter, ending March at less than 1.5 Tcf, which would be 12% less than the 2017–21 average for that time of year.

- We estimate dry natural gas production averaged 93.3 Bcf/d in the United States during the third quarter of 2021—up from 91.6 Bcf/d in in the first half of 2021. Production in the forecast rises to an average of 94.0 Bcf/d during the winter, and averages 96.4 Bcf/d during 2022, driven by natural gas and crude oil prices, which we expect to remain at levels that will support enough drilling to sustain production growth.

Electricity, coal, renewables, and emissions

- We expect the share of electricity generation produced by natural gas in the United States will average 36% in 2021 and 35% in 2022, down from 39% in 2020. In 2021, our forecast share for natural gas as a generation fuel declines in response to our expectation of a higher delivered natural gas price for electricity generators, which we forecast will average $5.15/MMBtu compared with $2.39/MMBtu in 2020. As a result of the higher expected natural gas prices, the forecast share of electricity generation from coal rises from 20% in 2020 to about 24% in 2021 and 23% in 2022. For renewable energy sources, new additions of solar and wind generating capacity are offset somewhat by reduced generation from hydropower this year, resulting in the forecast share of all renewables in U.S. electricity generation to average 20% in 2021, about the same as last year, before rising to 22% in 2022. The nuclear share of U.S. electricity generation declines from 21% in 2020 to 20% in 2021 and 2022.

- Electricity generation from coal-fired power plants has not increased as much in response to rising natural gas prices as it has in the past, or by as much as our models forecasted in recent STEOs. The lower price responsiveness of coal for electricity generation, which is likely the result of constraints on coal supply and low coal stocks, is contributing to upward pressure on natural gas prices. To reflect the lower price responsiveness of coal-fired electricity generation, we have lowered our forecast for U.S. coal generation for the fourth quarter of 2021 and the first half of 2022 by an average of 7 billion kWh (9%) each month, and we have raised our forecast for natural gas generation 5 billion kWh (5%) each month.

- We forecast that planned additions to U.S. wind and solar capacity in 2021 and 2022 will increase electricity generation from those sources. We estimate that the U.S. electric power sector added 14.6 gigawatts (GW) of new wind capacity in 2020. We expect 17.1 GW of new wind capacity will come online in 2021 and 6.5 GW in 2022. Utility-scale solar capacity rose by an estimated 10.5 GW in 2020. Our forecast for added utility-scale solar capacity is 16.0 GW for 2021 and 18.3 GW for 2022. We expect significant solar capacity additions in Texas during the forecast period. In addition, we project that after increasing by 4.5 GW in 2020, small-scale solar capacity (systems less than 1 megawatt) will grow 5.8 GW and 7.8 GW in 2021 and 2022, respectively.

- Coal production in our forecast totals 588 million short tons (MMst) in 2021, 53 MMst more than in 2020. We expect demand for coal from the electric power sector to increase by 84 MMst in 2021. Production growth is unlikely to match the increases in demand in the near term due to many coal mines operating at a reduced capacity and limited available transportation. In 2022, we expect coal production to increase by 34 MMst to 622 MMst, as the production and transportation constraints experienced in 2021 ease. Secondary inventories of coal at electric utilities decreased in the first half of 2021, and we forecast this trend will continue into the second half of 2021 and 2022.

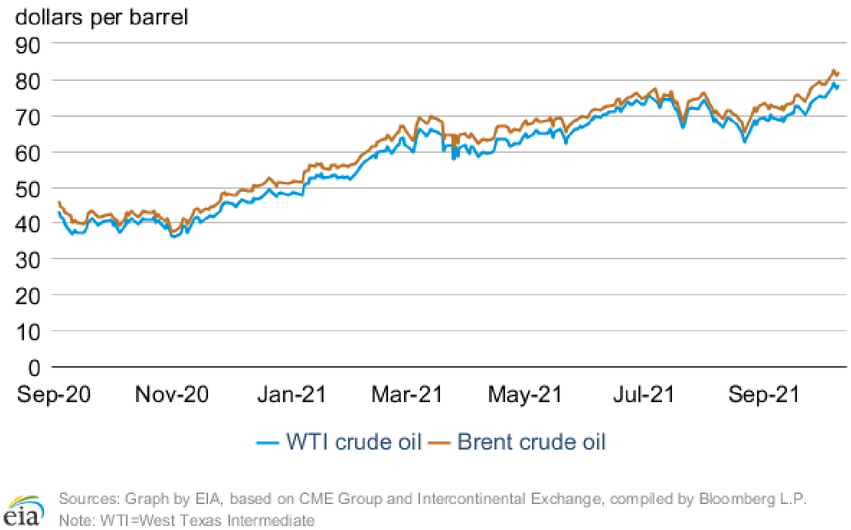
- We estimate that U.S. energy-related carbon dioxide (CO_2) emissions decreased by 11% in 2020 as a result of less energy consumption related to reduced economic activity and responses to COVID-19. For 2021, we forecast energy-related CO_2 emissions will increase about 8% from the 2020 level as economic activity increases and leads to rising energy use. We expect almost no change in energy-related CO_2 emissions in 2022. We forecast that after declining by 19% in 2020, coal-related CO_2 emissions will rise by 20% in 2021 and then fall by 5% in 2022. Short-term changes in energy-related CO_2 can be affected by temperature. A recent STEO supplement examines these dynamics.

Petroleum and natural gas markets review

Crude oil

Prices: The front-month futures price for Brent crude oil settled at $81.95 per barrel (b) on October 7, 2021, up $10.36/b from $71.59/b on September 1. The front-month futures price for West Texas Intermediate (WTI) crude oil for delivery at Cushing, Oklahoma, increased by $9.71/b during the same period, settling at $78.30/b on October 7 **(Figure 1)**.

Figure 1. Crude oil front-month futures prices

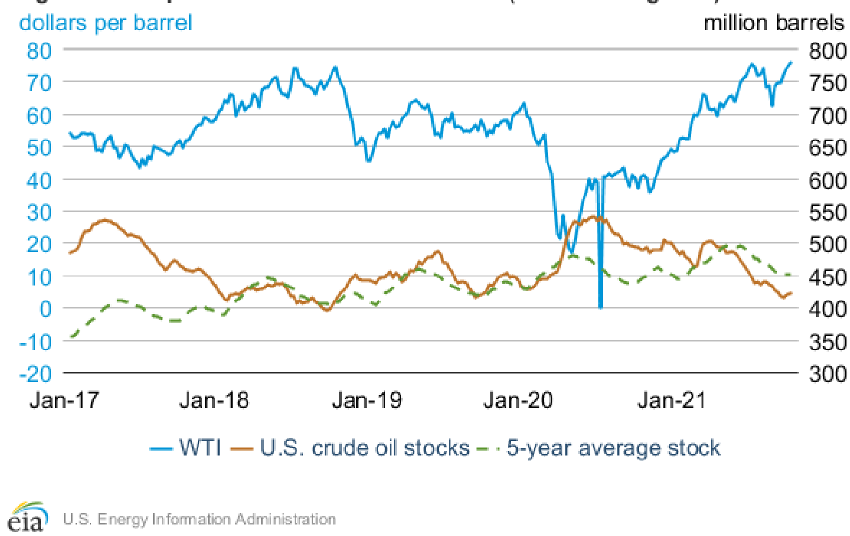


Sources: Graph by EIA, based on CME Group and Intercontinental Exchange, compiled by Bloomberg L.P.
Note: WTI=West Texas Intermediate

WTI crude oil prices reached nearly seven-year highs on October 5 after gradually increasing throughout September and the first few trading days of October. Several developments during the past month are contributing to higher oil prices. First, U.S. crude oil inventories have decreased because of Hurricane Ida's impact on crude oil production in the Gulf of Mexico. Second, OPEC+ members decided to follow their scheduled crude oil production increase of 400,000 barrels per day (b/d) in November rather than increase production by more, like some market participants expected based on recent price movements. Third, trade press reports increased purchases of oil and petroleum products as a result of high natural gas prices because electric power generators in parts of Asia and Europe may implement natural gas-to-oil fuel switching to decrease fuel costs. Lastly, crude oil prices continue to rise due to steady and sizable global oil inventory draws. We estimate that global inventories fell by 1.9 million b/d in third-quarter 2021 (3Q21), marking the fifth consecutive quarter of draws; quarterly draws averaged 2.2 million b/d over those five quarters.

We estimate U.S. crude oil inventories ended September at 420.9 million barrels, the lowest level since September 2018 **(Figure 2)**. U.S. crude oil stocks have decreased each of the past six months, decreasing by 81.0 million barrels (16%) since March, the largest six-month withdrawal on record in our crude oil data for all inventories outside of the Strategic Petroleum Reserve, which go back to 1973. Furthermore, according to weekly data in our *Weekly Petroleum Status Report*, crude oil stocks on September 17 were 37.0 million barrels (8.2%) below the five-year average for that time of year, the largest percentage below the five-year average since July 4, 2008. Like domestic stocks, we estimate OECD commercial petroleum stocks at the end of September to be at their lowest levels in more than three years.

Figure 2. WTI price and U.S. crude oil stocks (not including SPR)



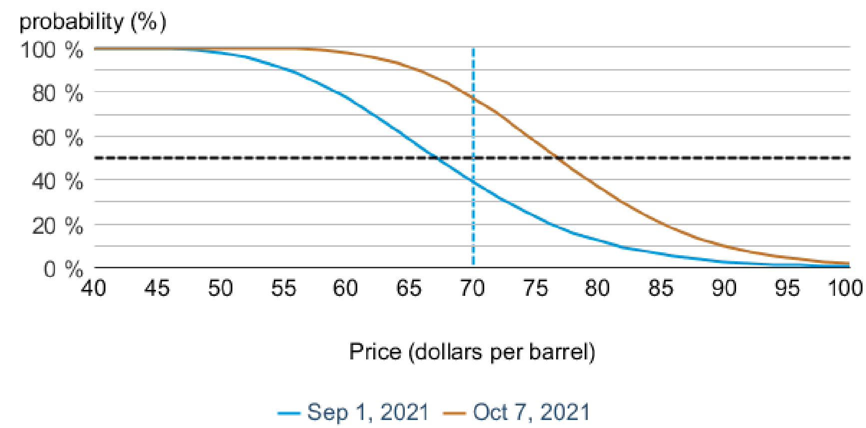
A major factor contributing to the stock draws has been low crude oil production, which has been outpaced by increases in demand. U.S. oil production averaged 11.0 million b/d from January through August (compared with 12.0 million b/d in the same months in 2019) and decreased to 10.6 million b/d in September because of lower U.S. offshore oil production in the Gulf of Mexico after Hurricane Ida. According to the Bureau of Safety and Environmental Enforcement (BSEE), from August 28 through September 6, more than 80% of oil production in the Gulf of Mexico was shut in, and more than 15% of Gulf of Mexico oil remained shut in through September 23, when BSEE issued its final outage report for Hurricane Ida. In total, disruptions in the Gulf of Mexico reduced crude oil production by about 30 million barrels since Hurricane Ida formed in late August.

Global liquid fuels production has also risen more slowly than global demand this year. Production increased by 2.7 million b/d (3%) from January to September, whereas global consumption increased by 6.3 million b/d (7%) during the same period. Despite relatively low global production and rising crude oil prices, OPEC+ members reaffirmed a previously agreed on production increase of 400,000 b/d in November, as opposed to a higher production increase for the month. Following this announcement on October 4, the price of Brent crude oil settled at $81.26, after beginning the day at $79.28.

In this forecast, we now expect that global oil inventories in 4Q21 and 1Q22 will fall at a faster rate than we had previously expected, which largely reflects lower global oil supply during this period across a range of producers. We have also raised our expectations for global oil demand during winter 2021−22., In the October STEO, we have increased our forecast for Brent crude oil prices. We now expect falling global oil inventories will keep Brent prices near $80/b this winter, averaging $81/b in 4Q21 and $78/b in 1Q21, both of which are $10/b higher than forecast last month.

Market-derived probabilities: In our most recent forecast, we expect WTI prices to average $78/b in 4Q21. The upward price pressure and market uncertainties are apparent in market-derived price probabilities that are based on futures and options prices. The market-derived probability of the December WTI futures contract expiring higher than $70/b was 77% on October 7, and the probability of the contract expiring higher than $80/b was 37% **(Figure 3)**. On September 1, the market-derived probability of the December WTI futures contract expiring higher than $70/b had been 39%, and the probability of the contract expiring higher than $80/b was 12%. The increase in market-derived price expectations for the December WTI contract from September 1 to October 7 conveys the market's reaction to factors such as decreasing stocks and the potential for natural gas-to-oil switching. The December WTI contract has not expired at more than $70/b since 2014 and has not expired at more than $80/b since 2013.

Figure 3. Probability of the December WTI futures contracts expiring above different price levels



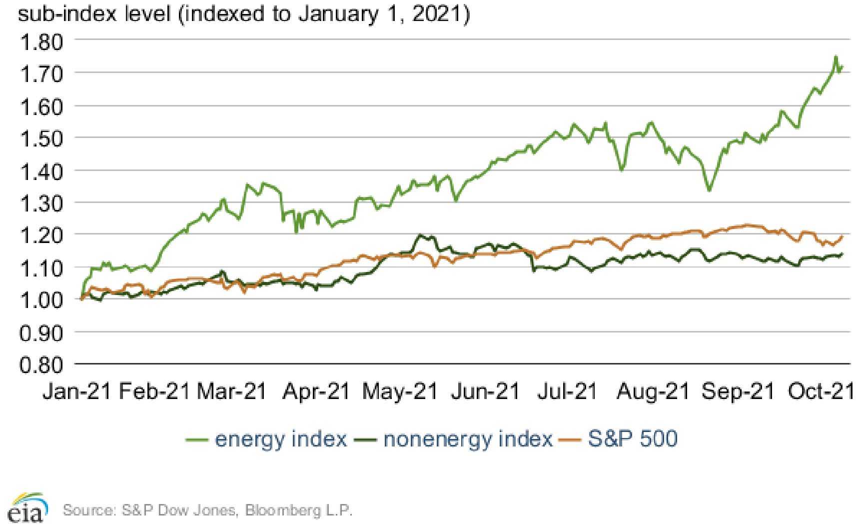
U.S. Energy Information Administration, CME Group
Note: WTI=West Texas Intermediate

Commodity Prices: In 2021, energy commodity prices have increased more than other commodities and asset classes, especially since May, primarily as a result of production and supply developments specific to energy markets. The S&P GSCI (formerly the Goldman Sachs Commodity Index) is an index comprising 24 individual weighted commodity price contracts organized into 5 subindexes, and we use it for comparing energy commodities to other categories of commodities.

As of October 7, the non-energy index (an index consisting of agricultural, livestock, precious metal, and industrial metal commodities) was up 14% from the beginning of 2021 but down 5%

from its peak on May 7. Energy commodities, on the other hand, have increased 27% since May 7 and are up 72% from January 1. The S&P 500, which is up by 19% from January 1, has also increased since May 7, but only by 4% **(Figure 4)**.

Figure 4. Energy versus nonenergy commodities and equities



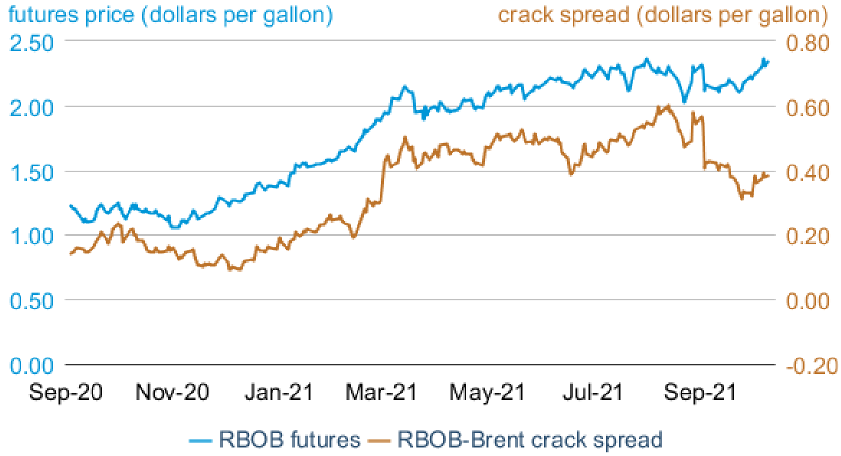
Source: S&P Dow Jones, Bloomberg L.P.

Whereas general economic growth likely explained a portion of the increase in energy prices from January 1 through May 7, the growth in energy commodities since then has mostly been a result of factors specific to petroleum markets, such as production increases lagging demand increases. Brent and WTI make up 70% of the energy sub-index's weight. Thus, the price increases from around $50/b for Brent and WTI at the beginning of the year to around $80/b in early October explains a significant portion of the increase in the energy sub-index. Higher prices for petroleum products, which make up 25% of the index, and for Henry Hub natural gas, which makes up the remaining 5% of the index, have also contributed to the rest of the growth in the energy sub-index.

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 $2.33 per gallon (gal) on October 7, up 22 cents/gal from September 1 **(Figure 5)**. The RBOB–Brent crack spread (the difference between the price of RBOB and the price of Brent crude oil) decreased by 2 cents/gal to settle at 38 cents/gal during the same period. The average RBOB–Brent crack spread in September was 38 cents/gal, an increase of 20 cents/gal compared with September 2020.

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

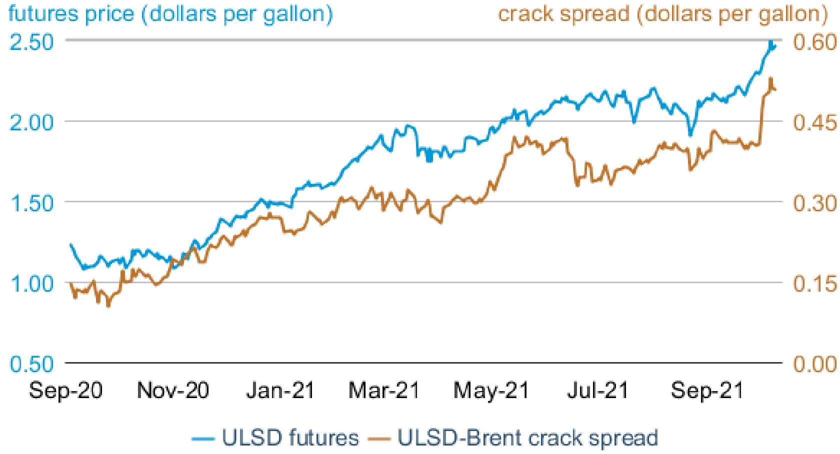


Source: Graph by EIA, based on data from CME Group, as compiled by Bloomberg L.P.
Note: RBOB is the petroleum component of gasoline used in many parts of the country.

After the RBOB–Brent crack spread averaged 55 cents/gal in August, it fell in September because of rising crude oil prices and lower gasoline prices. Lower gasoline prices compared with August reflect expected lower seasonal demand for gasoline as well as the price decrease for winter grade gasoline, which is relatively less expensive for refiners to produce because of less stringent Reid Vapor Pressure (RVP) requirements. The shift from summer to winter grade gasoline primarily takes place in September, putting downward pressure on the futures contract price in September onward. Temporary weather-related refinery outages along the U.S. Gulf Coast contributed to reduced production and draws on gasoline inventories earlier in September and limited some of the downward pressure on crack spreads. Compared with August 2021, U.S. demand for gasoline in September was an estimated 0.4 million barrels per day (b/d) lower. We estimate U.S. gasoline consumption averaged 9.1 million b/d in September, which is 0.5 million b/d (6%) higher than in September 2020 but also 0.1 million b/d (1%) lower than September 2019 level. We expect gasoline consumption to remain just below 2019 levels through the end of 2022. Combined with high net imports and lower demand, inventories increased during the second half of September; however, lost production from earlier in the month resulted in gasoline stocks ending September at 225.1 million barrels, the lowest end-of-September inventory level since 2017. Overall lower inventories may also have contributed to increasing gasoline crack spreads from October 4 through October 7.

Ultra-low sulfur diesel prices: The front-month futures price for ultra-low sulfur diesel (ULSD) for delivery in New York Harbor settled at $2.46/gal on October 7, up 33 cents/gal from September 1 **(Figure 6)**. The ULSD-Brent crack spread (the difference between the price of ULSD and the price of Brent crude oil) increased 8 cents/gal during the same period and settled at 51 cents/gal on October 7. The ULSD–Brent crack spread averaged 41 cents/gal in September.

Figure 6. Historical ULSD front-month futures prices and crack spreads

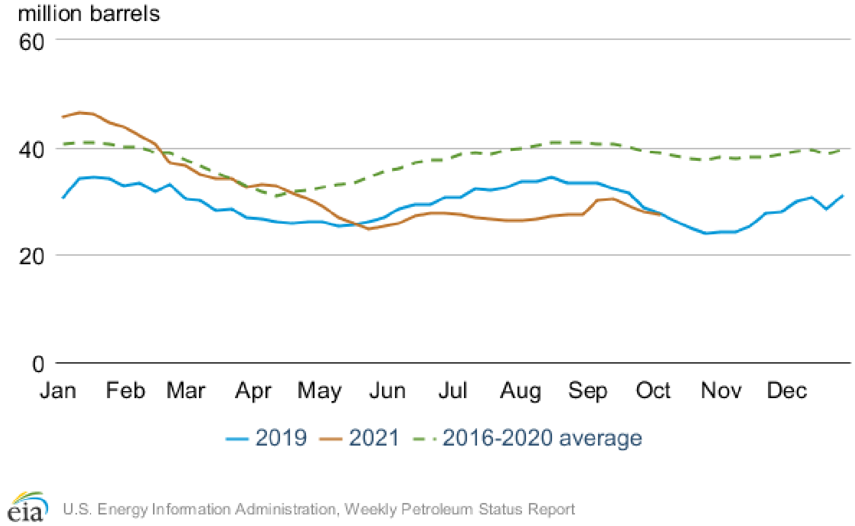


Source: Graph by EIA, based on data from CME Group, as compiled by Bloomberg L.P.
Note: ULSD=ultra-low sulfur diesel

High distillate demand and low distillate production resulted in the highest ULSD-Brent crack spreads seen this year, continuing a trend of rising ULSD crack spreads in recent months. We estimate that distillate consumption was 4 million b/d in September—the highest September level since 2018. Hurricane-related disruptions, including refinery shutdowns and brief closures of Colonial Pipeline Line 2, contributed to reduced production and higher inventory withdrawals. Also, increases in the American Trucking Associations' Truck Tonnage Index and the Cass Freight Index suggest trucking demand remains high as supply chains continue to navigate a backlog of shipping orders. Rapidly rising shipping activity will likely contribute to high distillate demand. While we forecast gasoline demand to remain below 2019 levels throughout 2022, we forecast distillate demand to increase next year to its highest level since 2018.

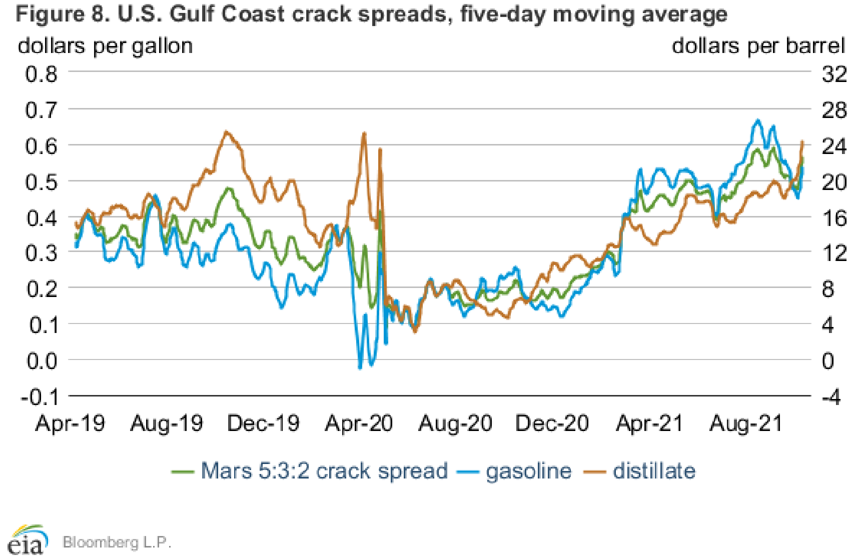
Rising crack spreads also likely reflect relatively low distillate fuel inventories. Distillate inventories typically increase in the summer to prepare for growth in demand in the fall and winter, when diesel-powered agricultural equipment is used to harvest crops and the winter heating season begins. This year, distillate inventories did not build as much as usual due to high distillate demand and relatively low production. Second- and third-quarter distillate production was 5.5% and 5.1% below the five-year (2016–20) average, respectively. Our estimate of 4.5 million b/d for production this September is 6.9% below the five-year average. As a result, U.S. distillate stocks are below average for this time of year. In the Northeast, where 4.14 million households will use heating oil as their primary source of heat this winter, distillate inventories declined to 27.4 million barrels (30% below the five-year average), according to the latest *Weekly Petroleum Status Report* **(Figure 7)**. Our *Winter Fuels Outlook* forecasts a 43% increase in heating oil expenditure over last year and the highest price per gallon for heating oil since the 2012–13 winter.

Figure 7. Northeast (PADD 1A and 1B) total distillate inventories



U.S. Gulf Coast crack spreads: The Mars crude oil 5:3:2 crack spread at the U.S. Gulf Coast is an indicator of profitability of gasoline and diesel-producing refinery operations for high-conversion refineries along the U.S. Gulf Coast that are able to process denser, more sour crude oil grades, such as Mars. On August 31, the five-day moving average crack spread reached 56 cents/gal, its highest point in 2021 **(Figure 8)**. The high overall crack spread primarily reflects increased gasoline cracks, which also reached an annual high in August. Gasoline crack spreads in the first half of September were elevated because of temporary hurricane outages, which supported the 5:3:2 crack through the middle of the month, continuing the trend from August, as well as increasing distillate crack spreads as the outages resulted in distillate inventory withdrawals. As supply constraints were resolved and refineries came back online, gasoline cracks decreased while distillate cracks continued to increase.

Figure 8. U.S. Gulf Coast crack spreads, five-day moving average

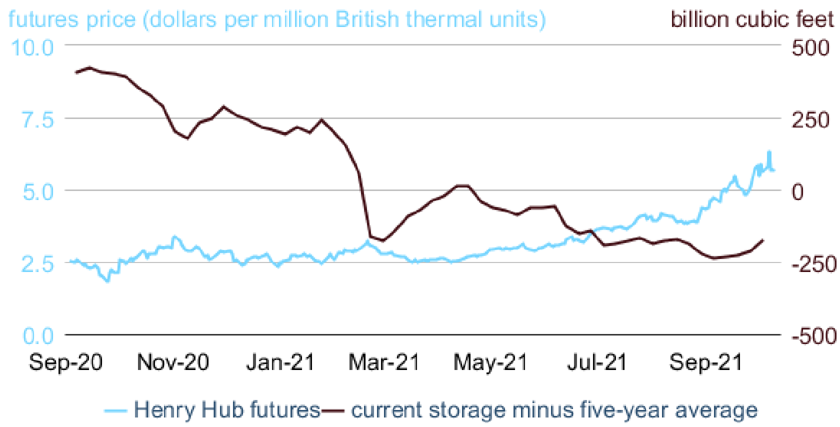


Higher crude oil costs, pressure on gasoline prices from the shift to winter grade, decreasing prices for renewable identification numbers (RINs), and seasonally lower demand has contributed to decreases in gasoline crack spreads in the latter half of September, while lower inventories and increasing seasonal demand continued to contribute to increasing diesel cracks. In addition to elevated crude oil prices globally, production outages in the Gulf Coast limited heavy sour crude oil production in August, and Mars grade in particular has faced extended production outages. As gasoline cracks decreased and distillate cracks increased, the distillate crack spread overtook the gasoline crack spread on September 23 and has remained higher so far into October. The relatively larger reduction in gasoline cracks compared with increasing distillate cracks contributed to decreases in the Mars 5:3:2 crack, which fell from 49 cents/gal on September 15 to 45 cents/gal on September 30. Since October 1, the gasoline and diesel crack five-day average crack spreads have both been increasing, contributing to increases in the Mars 5:3:2 crack as well.

Natural Gas

Prices: The front-month natural gas futures contract for delivery at the Henry Hub settled at $5.68 per million British thermal units (MMBtu) on October 7, 2021, which was up $1.06/MMBtu from September 1, 2021 **(Figure 9)**. The average price for front-month natural gas futures contracts in September was $5.11/MMBtu, the highest monthly average since February 2014. Henry Hub natural gas prices during much of the summer were supported by inventory builds that were below the previous five-year (2016–20) averages. Over the past month, increases in Henry Hub prices have coincided with sharp increases in international prices for natural gas, especially in Europe and Asia, and high international prices have contributed to strong demand for more U.S. liquefied natural gas (LNG) cargoes.

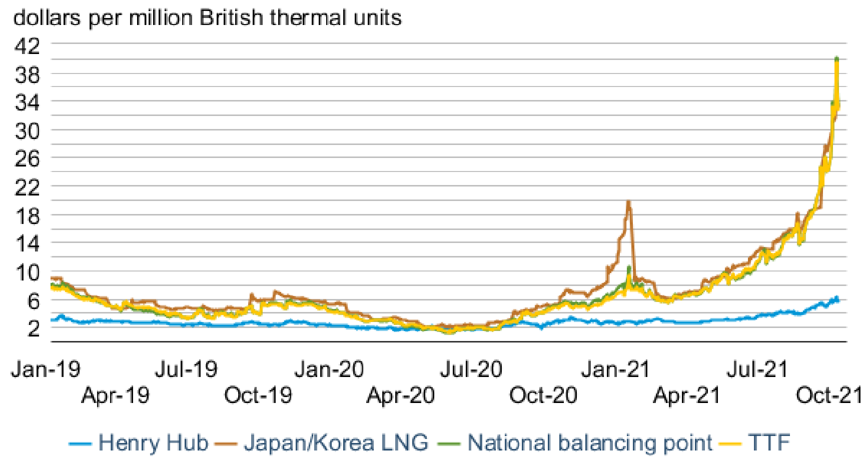
Figure 9. U.S. natural gas front-month futures prices and storage deviation from five-year average



Source: Graph by EIA, based on data from CME Group, as compiled by Bloomberg L.P.

International natural gas prices: LNG spot and forward prices in Europe and Northern Asia ended September at record-high levels. On September 30, 2021, LNG spot prices for Japan/Korea reached $31.10/MMBtu, and the price at the European natural gas benchmark, Title Transfer Facility (TTF), reached $33.20/MMBtu **(Figure 10)**. From the end of January to the end of September, the price spread between LNG prices in Asia and Henry Hub has increased from $6.31/MMBtu to $25.23/MMBtu. The price spread between European spot natural gas prices at TTF and Henry Hub increased from $4.49/MMBtu to $27.34/MMBtu over the same period. These large price differences have supported record LNG exports from the United States to Europe and Asia. U.S. LNG exports also increased because of new export capacity added in 2020. The final liquefaction units were commissioned at Freeport, Cameron, and Corpus Christi LNG, and the remaining small-scale units were placed in service at Elba Island LNG. Additionally, we expect Sabine Pass train 6 and Calcasieu Pass LNG facility to begin exporting by the end of the year.

Figure 10. International natural gas prices



Source: Graph by EIA, based on data from CME Group, as compiled by Bloomberg L.P.
Note: TTF=Title Transfer Facility

High natural gas demand in Asia, particularly in China because of disruptions in coal availability, contributed to increased demand for spot LNG shipments in addition to volumes supplied under long-term contracts. U.S. exports of LNG to China nearly quadrupled, increasing from 0.3 billion cubic feet per day (Bcf/d) for the first seven months of 2020 to 1.1 Bcf/d for the same period in 2021. U.S. LNG exports to Japan and South Korea increased by 64% and 62%, respectively, over the same period.

Low European natural gas storage inventories this year have led to high natural gas spot prices in that region as well. According to data from Gas Infrastructure Europe's (GIE) Aggregated Gas Storage Inventory (AGSI+), natural gas stocks in Europe ended September at 2.7 trillion cubic feet, 16% below the five-year average and 8% below the five-year minimum. Colder-than-normal weather late in the 2020–21 heating season and a cold spell in April led to rapid drawdowns of natural gas inventories early in 2021, contributing to the low inventory levels that are putting upward pressure on prices.

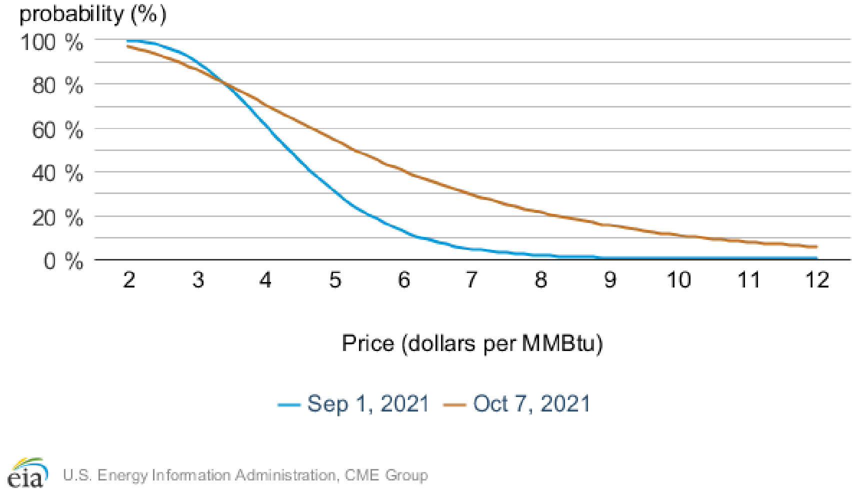
U.S. consumption and price outlook: Consumption of natural gas in the United States tends to decrease in September and October as temperatures are mild. U.S. consumption of natural gas decreased in September by 6.1 billion cubic feet per day (Bcf/d), or 7.9%, compared with August. This decrease was driven by a 6.7 Bcf/d decrease in natural gas consumption in the electric power sector that was partially offset by increases in the commercial, residential, and industrial sectors. U.S. exports of LNG also decreased in September, averaging 9.3 Bcf/d for the month, down from 9.7 Bcf/d in August. Annual maintenance at the Cove Point LNG facility in Maryland began in mid-September, and a power outage in Houston following Hurricane Nicholas resulted in the Freeport LNG terminal shutting down for a few days. Both of these events contributed to lower LNG exports in September. We expect LNG exports to average 10.7 Bcf/d this winter (October−March), a record high for that time period.

We estimate that U.S. working natural gas inventories ended September at 3,304 Bcf, 5.5% below the 2016–2020 average. This level is a decrease in the deficit to the 2016–2020 average when compared with August, which ended the month at 7.4% below the 2016–2020 average.

We expect that Henry Hub prices will remain high this winter, averaging $5.67/MMBtu in the forecast for October through March, which would be the highest winter average since winter 2007–08. However, the price outlook for this winter is very uncertain. Given that natural gas inventories in the United States are below average levels from recent years, the possibility that prices could be volatile is high, particularly if any area in the United States experiences a severe cold snap. Uncertainty in the price forecast also results from linkages between U.S. natural gas markets and global markets. With high demand for U.S. natural gas exports, increases in global natural gas prices have coincided with smaller price increases at Henry Hub.

Given the uncertainty surrounding natural gas prices, market-derived probabilities based on futures and options contracts are showing very wide range of market-implied price outcomes for the January Henry Hub futures contract **(Figure11)**. As of October 7, the market-derived probabilities implied that the January contract had about a 10% chance of expiring below $2.70/MMBtu and an equal chance of expiring above $10.25/MMBtu. A month earlier that probability range was bounded by $3.00/MMBtu on the low end and about $6.25/MMBtu on the high end. This shift shows that the market is increasingly pricing in the possibility of large price shifts in the coming months.

Figure 11. Probability of January 2022 natural gas futures contracts expiring above different price levels



Notable forecast changes

- We forecast Brent crude oil prices will average $81 per barrel (b) during the fourth quarter of 2021 (4Q21) and $78/b during 1Q22, both of which are $10/b higher than our previous forecast. The higher forecast reflects much tighter oil markets during this period than we previously expected. We now expect that global oil inventories in 4Q21 and 1Q22 will decline at an average rate of 0.5 million barrels per day (b/d), compared with a forecast of mostly unchanged inventories during that period in last month's STEO.

- We expect crude oil production in the Federal Offshore Gulf of Mexico will average 1.5 million b/d in 4Q21, more than 0.2 million b/d lower than forecast last month. The lower forecast is mostly the result of Shell's announcement that platforms damaged by Hurricane Ida would remain offline through the end of the year.

- We forecast Henry Hub spot prices will average $5.80 per million British thermal units (MMBtu) in 4Q21, an increase of $1.80/MMBtu from last month's STEO. In this outlook, we expect prices to remain elevated through the first quarter of 2022. Forecast Henry Hub prices for 2022 average $4.01/MMBtu, up 54 cents/MMBtu from last month's STEO.

- In mid-September, Exelon announced that it will continue operating its nuclear reactors at the Byron and Dresden power plants in Illinois. These nuclear plants were previously scheduled to be retired next year. As a result of this decision, we raised our forecast for U.S. nuclear generation in 2022 by 4% above the level forecast in last month's STEO.

Table 3a. International Petroleum and Other Liquids Production, Consumption, and Inventories

U.S. Energy Information Administration | Short-Term Energy Outlook - October 2021

	2020				2021				2022				Year		
	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	2020	2021	2022
Supply (million barrels per day) (a)															
OECD	33.05	29.27	29.95	30.66	30.18	30.86	30.87	31.73	32.37	32.51	32.74	33.27	30.73	30.91	32.72
U.S. (50 States)	20.33	17.44	18.29	18.29	17.62	19.05	18.56	18.98	19.54	19.83	20.18	20.45	18.58	18.55	20.01
Canada	5.64	4.90	4.94	5.54	5.63	5.39	5.56	5.79	5.83	5.80	5.82	5.85	5.26	5.59	5.82
Mexico	2.00	1.94	1.91	1.90	1.93	1.95	1.91	1.91	1.94	1.90	1.86	1.83	1.94	1.92	1.88
Other OECD	5.08	4.99	4.81	4.93	5.00	4.47	4.85	5.04	5.06	4.97	4.87	5.14	4.95	4.84	5.01
Non-OECD	67.69	63.03	61.06	62.09	62.62	63.90	65.76	67.42	67.39	68.53	69.26	69.18	63.46	64.94	68.60
OPEC	33.50	30.72	28.65	30.00	30.37	30.78	32.24	33.39	33.66	33.84	34.01	34.05	30.71	31.71	33.89
Crude Oil Portion	28.28	25.65	23.63	24.88	25.08	25.51	26.88	27.96	28.06	28.38	28.49	28.49	25.60	26.37	28.36
Other Liquids (b)	5.22	5.07	5.02	5.12	5.29	5.27	5.36	5.43	5.59	5.47	5.52	5.56	5.11	5.34	5.53
Eurasia	14.72	13.16	12.70	13.12	13.38	13.61	13.61	14.21	14.46	14.66	14.77	14.97	13.42	13.71	14.72
China	4.96	4.92	4.96	4.91	5.05	5.09	5.06	5.07	5.06	5.09	5.09	5.14	4.94	5.07	5.09
Other Non-OECD	14.51	14.22	14.75	14.06	13.82	14.42	14.84	14.74	14.22	14.93	15.39	15.02	14.38	14.46	14.89
Total World Supply	100.74	92.30	91.02	92.75	92.80	94.76	96.64	99.15	99.75	101.04	102.00	102.45	94.19	95.86	101.32
Non-OPEC Supply	67.24	61.58	62.36	62.75	62.43	63.98	64.39	65.76	66.10	67.19	67.99	68.41	63.48	64.15	67.43
Consumption (million barrels per day) (c)															
OECD	45.50	37.45	42.27	42.84	42.29	43.86	45.31	45.90	45.52	45.14	46.13	46.07	42.02	44.35	45.72
U.S. (50 States)	19.50	16.07	18.45	18.72	18.45	20.03	20.15	20.01	19.85	20.37	20.83	20.66	18.19	19.67	20.43
U.S. Territories	0.17	0.15	0.16	0.17	0.20	0.18	0.18	0.19	0.20	0.18	0.19	0.20	0.16	0.19	0.19
Canada	2.42	1.97	2.25	2.14	2.12	2.10	2.38	2.41	2.38	2.33	2.43	2.41	2.19	2.25	2.39
Europe	13.34	11.01	12.88	12.51	11.90	12.56	13.69	13.65	13.25	13.27	13.57	13.21	12.43	12.96	13.32
Japan	3.78	2.93	3.06	3.53	3.73	3.08	3.03	3.44	3.66	2.98	3.08	3.40	3.33	3.32	3.28
Other OECD	6.30	5.34	5.47	5.77	5.89	5.91	5.86	6.20	6.17	6.00	6.04	6.20	5.72	5.97	6.10
Non-OECD	50.33	47.44	51.21	52.59	52.37	52.81	53.21	54.08	54.32	55.43	55.54	55.63	50.40	53.12	55.23
Eurasia	4.86	4.48	5.28	5.17	4.94	5.03	5.42	5.27	5.08	5.15	5.54	5.39	4.95	5.17	5.29
Europe	0.71	0.69	0.71	0.72	0.73	0.74	0.74	0.75	0.74	0.74	0.74	0.75	0.71	0.74	0.74
China	13.89	14.08	14.65	15.11	15.25	15.46	14.97	15.44	15.84	16.01	15.72	15.99	14.43	15.28	15.89
Other Asia	13.35	11.63	12.59	13.61	13.77	13.33	13.18	13.90	14.30	14.47	14.04	14.44	12.80	13.54	14.31
Other Non-OECD	17.53	16.55	17.98	17.99	17.67	18.25	18.90	18.72	18.36	19.07	19.50	19.06	17.51	18.39	19.00
Total World Consumption	95.83	84.90	93.47	95.43	94.66	96.67	98.52	99.98	99.84	100.57	101.67	101.70	92.42	97.47	100.95
Total Crude Oil and Other Liquids Inventory Net Withdrawals (million barrels per day)															
U.S. (50 States)	-0.49	-1.67	0.53	0.91	0.47	0.51	0.54	0.52	-0.14	-0.71	-0.09	0.38	-0.18	0.51	-0.14
Other OECD	-0.51	-1.16	0.04	0.69	0.77	0.14	0.43	0.10	0.07	0.08	-0.08	-0.36	-0.23	0.36	-0.07
Other Stock Draws and Balance	-3.91	-4.57	1.90	1.08	0.62	1.26	0.91	0.22	0.15	0.17	-0.17	-0.78	-1.36	0.75	-0.16
Total Stock Draw	-4.91	-7.40	2.46	2.68	1.86	1.91	1.88	0.84	0.09	-0.46	-0.33	-0.75	-1.77	1.62	-0.37
End-of-period Commercial Crude Oil and Other Liquids Inventories (million barrels)															
U.S. Commercial Inventory	1,327	1,458	1,423	1,343	1,302	1,271	1,226	1,198	1,210	1,275	1,283	1,257	1,343	1,198	1,257
OECD Commercial Inventory	2,970	3,206	3,168	3,025	2,914	2,872	2,786	2,749	2,754	2,812	2,827	2,834	3,025	2,749	2,834

(a) Supply includes production of crude oil (including lease condensates), natural gas plant liquids, biofuels, other liquids, and refinery processing gains.

(b) Includes lease condensate, natural gas plant liquids, other liquids, and refinery processing gain. Includes other unaccounted-for liquids.

(c) Consumption of petroleum by the OECD countries is synonymous with "petroleum product supplied," defined in the glossary of the EIA *Petroleum Supply Monthly* , DOE/EIA-0109. Consumption of petroleum by the non-OECD countries is "apparent consumption," which includes internal consumption, refinery fuel and loss, and bunkering.

- = no data available

OECD = Organization for Economic Cooperation and Development: Australia, Austria, Belgium, Canada, Chile, the Czech Republic, Denmark, Estonia, Finland, France, Germany, Greece, Hungary, Iceland, Ireland, Israel, Italy, Japan, Latvia, Lithuania, Luxembourg, Mexico, the Netherlands, New Zealand, Norway, Poland, Portugal, Slovakia, Slovenia, South Korea, Spain, Sweden, Switzerland, Turkey, the United Kingdom, the United States.

OPEC = Organization of the Petroleum Exporting Countries: Algeria, Angola, Congo (Brazzaville), Equatorial Guinea, Gabon, Iran, Iraq, Kuwait, Libya, Nigeria, Saudi Arabia, the United Arab Emirates, Venezuela.

Notes: EIA completed modeling and analysis for this report on October 7, 2021.

The approximate break between historical and forecast values is shown with historical data printed in bold; estimates and forecasts in italics.

Historical data: Latest data available from Energy Information Administration international energy statistics.

Minor discrepancies with published historical data are due to independent rounding.

Forecasts: EIA Short-Term Integrated Forecasting System.

Table 4a. U.S. Petroleum and Other Liquids Supply, Consumption, and Inventories

U.S. Energy Information Administration | Short-Term Energy Outlook - October 2021

	2020				2021				2022				Year		
	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	2020	2021	2022
Supply (million barrels per day)															
Crude Oil Supply															
Domestic Production (a)	12.81	10.67	10.79	10.87	10.69	11.28	10.98	11.13	11.54	11.64	11.78	11.96	11.28	11.02	11.73
Alaska	0.48	0.41	0.44	0.46	0.46	0.44	0.39	0.44	0.43	0.42	0.39	0.43	0.45	0.43	0.42
Federal Gulf of Mexico (b)	1.99	1.66	1.43	1.50	1.80	1.79	1.46	1.50	1.76	1.73	1.74	1.77	1.64	1.64	1.75
Lower 48 States (excl GOM)	10.35	8.60	8.92	8.91	8.44	9.05	9.13	9.20	9.34	9.49	9.65	9.76	9.19	8.95	9.56
Crude Oil Net Imports (c)	2.89	3.06	2.24	2.50	2.87	2.96	3.60	3.82	3.80	4.62	4.81	3.87	2.67	3.32	4.28
SPR Net Withdrawals	0.00	-0.23	0.15	0.04	0.00	0.18	0.04	0.22	0.00	0.00	0.00	0.10	-0.01	0.11	0.03
Commercial Inventory Net Withdrawals	-0.56	-0.54	0.38	0.13	-0.18	0.59	0.29	-0.11	-0.33	-0.04	0.26	-0.02	-0.14	0.15	-0.03
Crude Oil Adjustment (d)	0.63	0.20	0.46	0.36	0.42	0.63	0.59	0.16	0.22	0.22	0.23	0.16	0.41	0.45	0.21
Total Crude Oil Input to Refineries	15.77	13.16	14.02	13.90	13.81	15.65	15.50	15.23	15.23	16.43	17.07	16.08	14.21	15.05	16.21
Other Supply															
Refinery Processing Gain	1.02	0.82	0.93	0.92	0.84	0.97	0.96	1.05	1.06	1.05	1.09	1.10	0.92	0.95	1.07
Natural Gas Plant Liquids Production	5.17	4.96	5.34	5.22	4.86	5.46	5.33	5.51	5.67	5.83	5.97	6.07	5.17	5.29	5.88
Renewables and Oxygenate Production (e)	1.11	0.81	1.03	1.07	1.03	1.13	1.08	1.08	1.07	1.10	1.12	1.11	1.01	1.08	1.10
Fuel Ethanol Production	1.02	0.70	0.92	0.97	0.90	0.99	0.97	0.98	0.97	1.00	1.01	1.00	0.91	0.96	1.00
Petroleum Products Adjustment (f)	0.22	0.19	0.20	0.19	0.19	0.22	0.21	0.21	0.20	0.22	0.22	0.22	0.20	0.21	0.22
Product Net Imports (c)	-3.86	-2.96	-3.07	-3.33	-2.94	-3.13	-3.13	-3.48	-3.58	-3.59	-4.30	-4.22	-3.30	-3.17	-3.92
Hydrocarbon Gas Liquids	-1.95	-1.84	-1.83	-2.06	-2.02	-2.23	-2.21	-2.24	-2.23	-2.28	-2.38	-2.34	-1.92	-2.18	-2.31
Unfinished Oils	0.37	0.23	0.35	0.18	0.14	0.25	0.36	0.29	0.21	0.26	0.30	0.20	0.29	0.26	0.24
Other HC/Oxygenates	-0.09	-0.04	-0.04	-0.04	-0.08	-0.04	-0.05	-0.05	-0.05	-0.04	-0.03	-0.03	-0.05	-0.05	-0.04
Motor Gasoline Blend Comp.	0.40	0.37	0.49	0.44	0.55	0.79	0.68	0.13	0.53	0.76	0.42	0.22	0.42	0.54	0.48
Finished Motor Gasoline	-0.71	-0.41	-0.58	-0.76	-0.66	-0.66	-0.54	-0.63	-0.87	-0.62	-0.65	-0.80	-0.62	-0.62	-0.74
Jet Fuel	-0.07	0.09	0.12	0.08	0.03	0.09	0.10	0.10	-0.06	-0.04	0.03	0.07	0.05	0.08	0.00
Distillate Fuel Oil	-1.14	-0.86	-1.16	-0.72	-0.49	-0.90	-0.89	-0.50	-0.59	-1.05	-1.28	-0.98	-0.97	-0.69	-0.98
Residual Fuel Oil	-0.02	-0.01	0.05	0.05	0.08	0.05	0.06	0.06	-0.02	0.00	-0.04	0.04	0.02	0.06	0.00
Other Oils (g)	-0.64	-0.49	-0.48	-0.48	-0.49	-0.49	-0.63	-0.62	-0.50	-0.59	-0.66	-0.61	-0.52	-0.56	-0.59
Product Inventory Net Withdrawals	0.06	-0.90	0.00	0.73	0.65	-0.26	0.20	0.41	0.19	-0.67	-0.35	0.30	-0.02	0.25	-0.13
Total Supply	19.50	16.07	18.45	18.72	18.43	20.03	20.15	20.01	19.85	20.37	20.83	20.66	18.19	19.66	20.43
Consumption (million barrels per day)															
Hydrocarbon Gas Liquids	3.37	2.85	3.01	3.68	3.40	3.33	3.12	3.53	3.80	3.33	3.34	3.84	3.23	3.35	3.58
Unfinished Oils	0.18	0.12	0.03	0.03	0.05	0.03	-0.03	0.00	0.00	0.00	0.00	0.00	0.09	0.01	0.00
Motor Gasoline	8.51	7.12	8.51	8.06	8.00	9.07	9.28	8.76	8.42	9.21	9.36	8.83	8.05	8.78	8.96
Fuel Ethanol blended into Motor Gasoline	0.85	0.73	0.87	0.85	0.82	0.93	0.93	0.89	0.86	0.94	0.95	0.92	0.82	0.89	0.92
Jet Fuel	1.56	0.69	0.97	1.09	1.13	1.34	1.52	1.52	1.46	1.57	1.71	1.68	1.08	1.38	1.61
Distillate Fuel Oil	4.02	3.49	3.70	3.94	3.97	3.93	3.90	4.14	4.17	4.05	4.02	4.17	3.79	3.99	4.11
Residual Fuel Oil	0.17	0.11	0.32	0.22	0.26	0.25	0.31	0.24	0.23	0.21	0.26	0.26	0.21	0.27	0.24
Other Oils (g)	1.69	1.68	1.92	1.71	1.63	2.08	2.06	1.82	1.76	2.00	2.15	1.87	1.75	1.90	1.94
Total Consumption	19.50	16.07	18.45	18.72	18.45	20.03	20.15	20.01	19.85	20.37	20.83	20.66	18.19	19.67	20.43
Total Petroleum and Other Liquids Net Imports	-0.97	0.11	-0.83	-0.84	-0.07	-0.16	0.47	0.35	0.22	1.03	0.51	-0.34	-0.63	0.15	0.35
End-of-period Inventories (million barrels)															
Commercial Inventory															
Crude Oil (excluding SPR)	483.3	532.7	497.7	485.5	501.9	448.0	420.9	430.8	460.3	464.0	440.1	442.3	485.5	430.8	442.3
Hydrocarbon Gas Liquids	182.9	235.7	298.7	228.2	168.6	195.8	218.1	170.6	133.0	187.3	235.1	197.1	228.2	170.6	197.1
Unfinished Oils	101.9	92.5	81.4	77.6	93.3	93.0	89.0	82.8	93.3	91.1	90.0	83.1	77.6	82.8	83.1
Other HC/Oxygenates	33.4	25.4	24.6	29.7	29.1	27.5	25.8	26.0	28.1	26.8	26.5	26.8	29.7	26.0	26.8
Total Motor Gasoline	261.8	254.5	227.6	243.4	237.6	237.2	225.1	234.1	241.9	246.6	233.3	249.3	243.4	234.1	249.3
Finished Motor Gasoline	22.6	23.5	22.5	25.4	20.3	18.6	17.6	24.4	24.1	23.9	23.1	26.2	25.4	24.4	26.2
Motor Gasoline Blend Comp.	239.2	231.0	205.0	218.0	217.4	218.6	207.5	209.7	217.8	222.7	210.2	223.2	218.0	209.7	223.2
Jet Fuel	39.9	41.6	40.1	38.6	39.0	44.7	41.3	38.6	38.4	39.5	42.1	39.1	38.6	38.6	39.1
Distillate Fuel Oil	126.8	176.9	172.5	161.2	145.5	140.1	129.3	133.9	124.2	129.4	136.6	137.6	161.2	133.9	137.6
Residual Fuel Oil	34.8	39.5	32.1	30.2	30.9	31.1	28.2	30.5	31.0	32.0	30.3	31.7	30.2	30.5	31.7
Other Oils (g)	61.9	59.0	48.3	49.1	55.8	54.1	48.1	50.6	59.8	57.8	48.6	50.2	49.1	50.6	50.2
Total Commercial Inventory	1326.7	1457.7	1423.2	1343.3	1301.7	1271.5	1225.7	1197.9	1210.0	1274.6	1282.7	1257.1	1343.3	1197.9	1257.1
Crude Oil in SPR	635.0	656.0	642.2	638.1	637.8	621.3	617.8	597.8	597.8	597.8	597.8	588.2	638.1	597.8	588.2

(a) Includes lease condensate.

(b) Crude oil production from U.S. Federal leases in the Gulf of Mexico (GOM).

(c) Net imports equals gross imports minus gross exports.

(d) Crude oil adjustment balances supply and consumption and was previously referred to as "Unaccounted for Crude Oil."

(e) Renewables and oxygenate production includes pentanes plus, oxygenates (excluding fuel ethanol), and renewable fuels. Beginning in January 2021, renewable fuels includes biodiesel, renewable diesel, renewable jet fuel, renewable heating oil, renewable naphtha and gasoline, and other renewable fuels. For December 2020 and prior, renewable fuels includes only biodiesel.

(f) Petroleum products adjustment includes hydrogen/oxygenates/renewables/other hydrocarbons, motor gasoline blend components, and finished motor gasoline.

(g) For net imports and inventories “Other Oils" includes aviation gasoline blend components, finished aviation gasoline, kerosene, petrochemical feedstocks, special naphthas, lubricants, waxes, petroleum coke, asphalt and road oil, still gas, and miscellaneous products; for consumption “Other Oils” also includes renewable fuels except fuel ethanol.

- = no data available

SPR: Strategic Petroleum Reserve

HC: Hydrocarbons

Notes: EIA completed modeling and analysis for this report on October 7, 2021.

The approximate break between historical and forecast values is shown with historical data printed in bold; estimates and forecasts in italics.

Historical data: Latest data available from Energy Information Administration databases supporting the following reports: *Petroleum Supply Monthly* , DOE/EIA-0109; *Petroleum Supply Annual* , DOE/EIA-0340/2; and *Weekly Petroleum Status Report* , DOE/EIA-0208.

Minor discrepancies with published historical data are due to independent rounding.

Forecasts: EIA Short-Term Integrated Forecasting System.

Table 5a. U.S. Natural Gas Supply, Consumption, and Inventories

U.S. Energy Information Administration | Short-Term Energy Outlook - October 2021

	2020				2021				2022				Year		
	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	2020	2021	2022
Supply (billion cubic feet per day)															
Total Marketed Production	103.02	96.83	97.29	98.53	97.31	100.79	101.23	101.60	102.39	103.50	105.35	107.06	98.91	100.25	104.59
Alaska	0.96	0.88	0.88	0.98	1.02	0.95	0.84	0.88	0.92	0.81	0.73	0.87	0.92	0.92	0.83
Federal GOM (a)	2.80	2.28	1.75	1.81	2.27	2.26	1.85	1.91	2.09	2.01	1.91	1.87	2.16	2.07	1.97
Lower 48 States (excl GOM)	99.25	93.68	94.67	95.75	94.03	97.58	98.54	98.80	99.38	100.68	102.72	104.32	95.83	97.25	101.79
Total Dry Gas Production	95.29	89.57	89.99	91.14	90.30	92.89	93.32	93.65	94.38	95.41	97.12	98.69	91.49	92.55	96.41
LNG Gross Imports	0.24	0.12	0.09	0.09	0.15	0.02	0.13	0.20	0.32	0.18	0.18	0.20	0.13	0.12	0.22
LNG Gross Exports	7.92	5.52	3.91	8.78	9.27	9.81	9.56	10.19	11.21	10.81	10.73	11.86	6.53	9.71	11.15
Pipeline Gross Imports	7.60	6.08	6.39	7.27	8.68	6.81	6.86	6.85	7.35	6.35	6.38	6.72	6.84	7.29	6.70
Pipeline Gross Exports	8.15	7.17	8.09	8.21	8.31	8.67	8.71	9.18	9.17	8.58	9.34	9.35	7.91	8.72	9.11
Supplemental Gaseous Fuels	0.18	0.17	0.17	0.17	0.18	0.15	0.16	0.17	0.17	0.17	0.18	0.18	0.17	0.16	0.17
Net Inventory Withdrawals	12.74	-12.24	-7.68	5.36	17.19	-9.12	-7.84	4.64	15.46	-10.68	-8.37	4.36	-0.46	1.16	0.14
Total Supply	99.98	71.00	76.96	87.05	98.91	72.26	74.36	86.13	97.31	72.04	75.42	88.92	83.74	82.86	83.38
Balancing Item (b)	-0.55	-0.29	-0.20	-0.93	0.37	-0.33	0.71	0.74	-0.89	-0.93	-0.95	-0.39	-0.49	0.37	-0.79
Total Primary Supply	99.44	70.72	76.76	86.12	99.28	71.92	75.08	86.88	96.42	71.11	74.47	88.54	83.25	83.23	82.59
Consumption (billion cubic feet per day)															
Residential	22.95	8.25	3.84	16.10	25.67	7.51	3.39	17.13	24.62	7.73	3.80	17.21	12.77	13.37	13.29
Commercial	14.04	5.85	4.39	10.40	14.87	6.24	4.78	11.47	14.63	6.61	5.15	11.71	8.66	9.32	9.51
Industrial	24.31	20.32	20.92	23.53	23.81	21.49	21.62	24.34	24.12	22.09	21.90	24.76	22.27	22.81	23.22
Electric Power (c)	29.55	29.05	40.10	28.19	26.65	29.14	37.61	25.84	24.56	27.02	35.75	26.41	31.74	29.83	28.46
Lease and Plant Fuel	5.14	4.83	4.85	4.91	4.85	5.02	5.05	5.06	5.10	5.16	5.25	5.34	4.93	5.00	5.21
Pipeline and Distribution Use	3.31	2.32	2.53	2.85	3.28	2.38	2.48	2.89	3.22	2.34	2.46	2.95	2.75	2.75	2.74
Vehicle Use	0.13	0.10	0.13	0.13	0.14	0.15	0.15	0.15	0.16	0.16	0.16	0.16	0.13	0.15	0.16
Total Consumption	99.44	70.72	76.76	86.12	99.28	71.92	75.08	86.88	96.42	71.11	74.47	88.54	83.25	83.23	82.59
End-of-period Inventories (billion cubic feet)															
Working Gas Inventory	2,029	3,133	3,840	3,341	1,801	2,583	3,304	2,878	1,486	2,458	3,228	2,827	3,341	2,878	2,827
East Region (d)	385	655	890	763	313	515	806	660	187	460	686	506	763	660	506
Midwest Region (d)	471	747	1,053	918	395	630	966	819	287	543	898	793	918	819	793
South Central Region (d)	857	1,221	1,313	1,155	760	991	1,048	999	728	985	1,057	982	1,155	999	982
Mountain Region (d)	92	177	235	195	113	175	205	154	99	152	220	203	195	154	203
Pacific Region (d)	200	308	318	282	197	246	247	213	153	286	334	311	282	213	311
Alaska	23	25	31	28	23	27	32	32	32	32	32	32	28	32	32

(a) Marketed production from U.S. Federal leases in the Gulf of Mexico.

(b) The balancing item represents the difference between the sum of the components of natural gas supply and the sum of components of natural gas demand.

(c) Natural gas used for electricity generation and (a limited amount of) useful thermal output by electric utilities and independent power producers.

(d) For a list of States in each inventory region refer to *Weekly Natural Gas Storage Report, Notes and Definitions (http://ir.eia.gov/ngs/notes.html)* .

\- = no data available

LNG: liquefied natural gas.

Notes: EIA completed modeling and analysis for this report on October 7, 2021.

The approximate break between historical and forecast values is shown with historical data printed in bold; estimates and forecasts in italics.

Historical data: Latest data available from Energy Information Administration databases supporting the following reports: *Natural Gas Monthly* , DOE/EIA-0130; and *Electric Power Monthly* ,

Minor discrepancies with published historical data are due to independent rounding.

Forecasts: EIA Short-Term Integrated Forecasting System.

https://clubofmozambique.com/news/mozambique-rwanda-and-sadc-military-commands-define-counter-terrorist-strategies-in-cabo-delgado-202775/

Mozambique, Rwanda and SADC military commands define counter-terrorist strategies in Cabo Delgado

4:12 CAT | 14 Oct 2021
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Commander of the Rwandan Force, Deputy Commander of the SADC Force, Commander of the Mozambican Army, Cristóvão Chume, Commander of the Rwanda Police Component and Commander of the Task Force

The Mozambican army says that all known terrorists bases in Cabo Delgado have been identified and dismantled.

The guarantee was given by the commander of the Mozambican armed forces Cristóvão Chume during a meeting of the commands of the forces involved in the military operations this Wednesday, October 13, in Mocímboa da Praia, Cabo Delgado province,

The military leaders of the forces of Mozambique, Rwanda and the Southern African Development Community (SADC) met for more than four hours to consider the situation in the northern operational theatre, envision future actions and, above all, improve the ability to coordinate in the fight against violent extremism.

Meeting of the joint command of the forces of Mozambique, Rwanda and SADC, Mocímboa da Praia, 13 October, 2021

"In Palma district, and also in Mocimboa da Praia district, approximately 100% of the known bases of the enemy were occupied by joint Mozambican and Rwandan troops. There is no formally known base that still prevails or is in an area under terrorist control. The area of operations assigned to SAMIM (the

SADC force), which is Macomia, Muidumbe and Nangade, also presents itself in the same way. There is no formal knowledge, as of now, of a base that has been identified before and that has not been occupied by our forces," said Cristóvão Chume, commander of the Mozambican Army, who nevertheless said that the fight against the terrorists was not over.

"We still continue to find the theatre of operations complex, as we still have areas where the enemy, in groups of six, seven or eight people attack, burning villages and killing defenceless citizens. So, as long as this situation prevails, we cannot consider the theatre of operations free from the enemy. But the situation that prevailed until the end of June, in which the enemy had an initiative to attack our forces, to attack and occupy spaces such as villages, and everything else – is no longer the same," Chume said.

Chume reiterated that the objective now was to cut the enemy's lines of communication between their hideouts and places where there is a possibility of getting food.

"That's what we're working on right now," he announced.

Rwandan troops on patrol in Mocímboa da Praia, Cabo Delgado, Mozambique

The military leaders of Mozambique, Rwanda and the SADC decided to establish a new joint command of operations, which will be led by Maputo and which will include teams involving elements from all sides.

The commander of the Mozambican army admitted that the war could "take a year, two years, three years".

"What we want is the total annihilation of the enemy. If this only takes a week, we will be satisfied. But what we are going to do is [ensure] that the suffering of our people is not prolonged for long periods of time. That's what we discussed," said Cristóvão Chume, without revealing how many terrorists had been captured or killed.

He concluded by saying only that all those who terrorised Cabo Delgado would be eliminated.

By Francisco Junior
Source: Voa Portugues

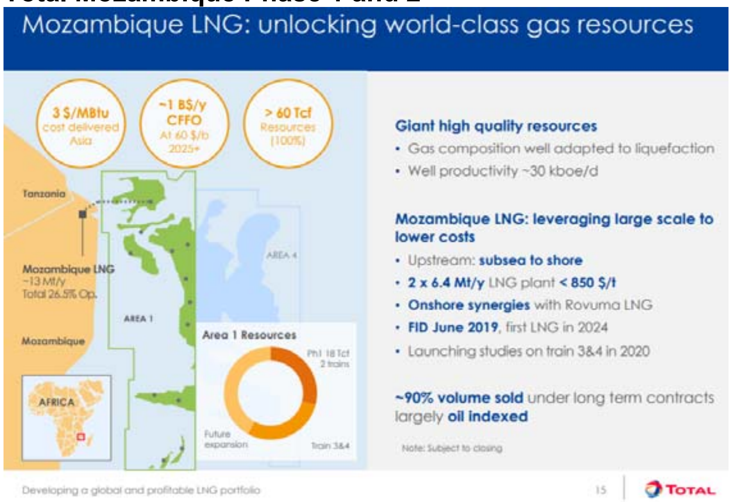
Multiple Brownfield LNG FIDs Now Needed To Fill New LNG Supply Gap From Mozambique Chaos? How About LNG Canada Phase 2?

Posted Wednesday April 28, 2021. 9:00 MT

The next six months will determine the size and length of the new LNG supply gap that is hitting harder and faster than anyone expected six months ago. Optimists will say the Mozambique government will bring sustainable security and safety to the northern Cabo Delgado province and provide the confidence to Total to quickly get back to LNG development such that its LNG in-service delay is a matter of months and not years. We hope so for Mozambique's domestic situation, but will it be that easy for Total's board to quickly look thru what just happened? Total suspended LNG development for 3 months, restarted development on March 25, but then 3 days of violence led it to suspend development again on March 28, and announce force majeure on Monday April 26. Even if the optimists are right, Mozambique LNG is counted on for LNG supply and the major LNG supply project that are in LNG supply forecasts are now all delayed – Total Phase 1 of 1.7 bcf/d and its follow on Phase 2 of 1.3 bcf/d, and Exxon's Rozuma Phase 1 of 2.0 bcf/d. It is important to remember this 5.0 bcf/d of major LNG supply is being counted in LNG supply forecasts and starting in 2024. At a minimum, we think the more likely scenario is a delay of at least 2 years in this 5.0 bcf/d from the pre-Covid timelines. And this creates a much bigger and sooner LNG supply gap starting ~2025 and stronger outlook for LNG prices. Thermal coal in Asia will play a role in keeping a lid on LNG prices. But there will be the opportunity for LNG suppliers to at least review the potential for brownfield LNG projects to fill the growing supply gap. The thought of increasing capex was a non-starter six months ago, but there is a much stronger outlook for global oil and gas prices. Oil and gas companies are pivoting from cutting capex to small increases in 2021 capex and expecting for higher capex in 2022. We believe this sets the stage for looking at potential FID of brownfield LNG projects before the end of 2021 to be included in 2022 capex budgets. Mozambique is causing an LNG supply gap that someone will try to fill. And if brownfield LNG is needed, what about Shell looking at 1.8 bcf/d brownfield LNG Canada Phase 2? Cdn natural gas producers hope so as this would mean more Cdn natural gas will be tied to Asian LNG markets and not competing in the US against Henry Hub.

Total declares force majeure on Mozambique LNG, Yesterday, Total announced [LINK] "*Considering the evolution of the security situation in the north of the Cabo Delgado province in Mozambique, Total confirms the withdrawal of all Mozambique LNG project personnel from the Afungi site. This situation leads Total, as operator of Mozambique LNG project, to declare force majeure. Total expresses its solidarity with the government and people of Mozambique and wishes that the actions carried out by the government of Mozambique and its regional and international partners will enable the restoration of security and stability in Cabo Delgado province in a sustained manner".* Total is working Phase 1 is ~1.7 bcf/d (Train 1 + 2, 6.45 mtpa/train) and was originally expected to being LNG deliveries in 2024. There was no specific timeline for Phase 2 of 1.3 bcf/d (Train 3 + 4, 5.0 mtpa/train), but was expected to follow Phase 1 in short order to keep capital costs under control with a continuous construction process with a potential onstream shortly after 2026.

Total Mozambique Phase 1 and 2



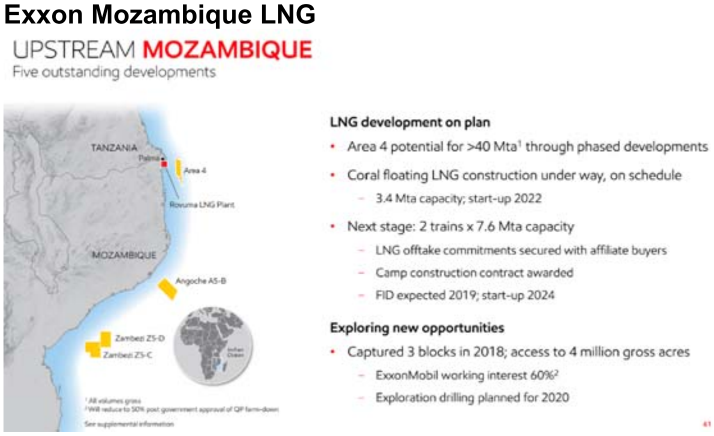
Source: Total Investor Day September 24, 2019

Total's Mozambique force majeure is no surprise, especially the need to the restoration of security and stability "in a sustained manner". Yesterday, Total announced [LINK] "*Considering the evolution of the security".* No one should be surprised by the force majeure or the sustained manner caveat. SAF Group posts a weekly Energy Tidbits research memo [LINK], wherein we have, in multiple weekly memos, that Total had shut down development in December for 3 months due to the violent and security risks. It restarted development on Wed March 24, violence/attacks immediately resumed for 3 consecutive days, and then Total suspended development on Sat March 27. Local violence/attacks shut development down in Dec, the situation gets settled enough for Total to restart in March, only to be shut down 3 days thereafter. No one should be surprised especially with Total's need to see security and stability "in a sustained manner".

Does anyone really think Total will risk another quick 2-3 month restart or even in 2021? The Mozambique government will be working hard to convince Total to restart soon. We just find it hard to believe Total board will risk a replay of March 24-27 in 2021. Unfortunately, Mozambique has had internal conflict for years. It reached a milestone to the positive in August 2019. Our SAF Group August 11, 2019 Energy Tidbits memo [LINK] highlighted the signing of a peace pact between Mozambique President Nyusi and leader of the Renamo opposition Momade. This was the official end to a 2013 thru 2016 conflict following a failure to hold up the prior peace pact. At that time, FT reported [LINK] "Mr Nyusi has said that "*the government and Renamo will come together and hunt" rebels who fail to disarm. The government has struggled to stem the separate insurgency in the north, which has killed or displaced hundreds near the gas-rich areas during the past two years. While the roots of the conflict remain murky, it is linked to a local Islamist group and appears to be drawing on disaffection over sharing gas investment benefits, say analysts*." This is just a reminder this is not a new issue. LNG is a game changer to Mozambique's economic future. It is, but also has been, a government priority to have the security and safety for Total and Exxon to move on their LNG developments. Its hard to believe the Mozambique government will be able to quickly convince Total and Exxon boards that they can be comfortable there is a sustained security/safety situation and they can send their people back in to develop the LNG. Total's board would allow any resumption of development before year end 2021. The last thing Total wants is a replay of March 24-27. The first question is how long will it take before the Total board is convinced its safe to restart. Could you imagine them doing a replay of what just happened? Wait three months, restart development and have to stop again right away? We have to believe that could lead the Total board to believe it is unfixable for years. We just don't think they are to prepared to risk that decision in 3 months. Its why we have to think there isn't a restart approval until at least in 2022 at the earliest ie. why we think the likely scenario is a delay of 2-3 years, and not a matter of months.

Mozambique's security issues pushes back 5.0 bcf/d of new LNG supply at least a couple years. The global LNG issue is that 5 bcf/d of new Mozambique LNG supply (apart from the Eni Coral FLNG of 0.45 bcf/d) won't start up in 2024 and continuing thru the 2020s. And we believe all LNG forecasts included this 5.0 bcf/d to be in service in the 2020s as Mozambique had been considered the best positioned LNG supply to access Asia after Australia and Papua New Guinea. (i) Eni Coral Sul (Rovuma Basin) FLNG of 0.45 bcf/d planned in service in 2022. [LINK] This is an offshore floating LNG vessel that is still expected to be in service in 2022. (ii) Total Phase 1 to add 1.7 bcf/d with an in service originally planned for 2024. We expect the in service data to be pushed back to at least 2026 assuming Total gives a development restart approval in Dec 2021. In theory, this would only be a 1 year loss of time. However, Total has let services go, the project will be idle for 9 months, it isn't clear if the need to get people out quickly let them do a complete put the project on hold, and how many people will be on site maintaining the status of the development during the force majeure. Also what new procedures and safety will be put in place for a restart. These all mean there will be added time needed to get the project back to where it was when force majeure was declared ie. why we think a 12 month time delay will be more like an 18 month project delay. (iii) Exxon's Rozuma Phase 1 LNG will add 2.0 bcf/d and, pre-Covid, was expected to be in service in 2025. We believe the delays related to security and safety at Total are also going to impact Exxon. We find it highly unlikely the Exxon board would take a different security and safety decision than Total. Pre-pandemic, Exxon's March 6, 2019 Investor Day noted their operated Mozambique Rovuma LNG Phase 1 was to be 2 trains each with 1.0 bcf/d capacity for total initial capacity of 2.0 bf/d with FID expected in 2019 and first LNG deliveries in 2024. The 2019 FID expectation was later pushed to be expected just before the March 2020 investor day. But the pandemic hit, and on March 21, 2020, we tweeted [LINK] on the Reuters story "*Exclusive: Coronavirus, gas slump put brakes on Exxon's giant Mozambique LNG plan*" [LINK] that noted Exxon was expected to delay the Rovuma FID. There was no timeline, but the expectation was that FID would now be in 2022 (3 years later than original timeline0 and that would push first LNG likely to 2027. (iv) Total Phase 2 was to add 1.3 bcf/d. There was no firm in service date but it was expected to follow closely behind Phase 1 to maintain services. That would have put it originally in the 2026/2027 period. But if Phase 1 is pushed back 2 years, so will Phase 2 so more likely 2028/2029.. (v) Total Phase 1 + 2 and Exxon Rozuma Phase 1 total 5.0 bcf/d and would have been (and still are) in all LNG supply forecasts for the 2020s. (vi) We aren't certain if the LNG supply forecasts include Exxon Rozuma Phase 2 ,which would be an additional 2.0 bcf/d on top of the 5.0 bcf/d noted above. Exxon Rozuma has always been expected to be at least 2 Phases. This has been the plan since the Anadarko days given the 85 tcf size of the resource on Exxon's Area 4. There was no firm in service data for Phase 2, but it was expected they would also closely follow Phase 1 to maintain services. We expect that original timeline would have been 2026/2027 and that would not be pushed back to 2029/2030. (vii) It doesn't matter if its only 5 bcf/ of Mozambique that is delayed 2 to 3 years, it will cause a bigger LNG supply gap and sooner. The issue for LNG markets is this is taking projects that are in development effectively out of the queue for some period.

Exxon Mozambique LNG



Source: Exxon Investor Day March 6, 2019

Won't LNG and natural gas get hit by Biden's push for carbon free electricity? Yes, in the US. For the last 9 months, we have warned on Biden's climate change plan that were his election platform and now form his administration's energy transition map. We posted our July 28, 2020 blog "*Biden To Put US On "Irreversible Path to Achieve Net-Zero Emissions, Economy-Wide" Is a Major Negative To US Natural Gas in 2020s* "[LINK] on Biden's platform "*The Biden Plan to Build a Modern, Sustainable Infrastructure and an Equitable Clean Energy Future*" [LINK]. Biden's new American Jobs Plan

[LINK] lines up with his campaign platform including to put the US "*on the path to achieving 100 percent carbon-free electricity by 2035*.". Our July 28, 2020 blog noted that it would require replacing ~60% of US electricity generation with more renewable and it could eliminate ~40% (33.5 bcf/d) of 2019 US natural gas consumption. If Biden is 25% successful by 2030, it would replace ~6.3 bcf/d of natural gas demand. It would be a negative to US natural gas and force more US natural gas to export markets. The wildcard when does US natural gas start to decline if producers are faced with the reality of natural gas being phased out for electricity. The other hope is that when Biden says "carbon-free", its not what ends up in the details of any formal policy statement ie. carbon electricity will be allowed with Biden's push for CCS.

Will Cdn natural gas be similarly hit by if Trudeau move to "emissions free" and not "net zero emissions" electricity? Yes and No. Our SAF Group April 25, 2021 Energy Tidbits memo [LINK] was titled ""*Bad News For Natural Gas, Trudeau's Electricity Goal is Now 100% "Emissions Free" And Not "Net Zero Emissions*". On Thursday, PM Trudeau spoke at Biden's global climate summit [LINK] and looks like he slipped in a new view on electricity than was in last Monday's budget and his Dec climate plan. Trudeau said "*In Canada, we've worked hard to get to over 80% emissions-free electricity, and we're not going to stop until we get to 100%."* Speeches, especially ones made on a global stage are checked carefully so this had to be deliberate. Trudeau said "*emissions free*" and not net zero emissions electricity. It seems like this language is carefully written to exclude any fossil fuels as they are not emissions free even if they are linked to CCS. Recall in Liberals big Dec 2020 climate announcement [LINK], Liberals said ""*Work with provinces, utilities and other partners to ensure that Canada's electricity generation achieves net-zero emissions before 2050*." There is no way Trudeau changed the language unless he meant to do so. And this is a major change as it would seem to indicate his plan to eliminate all fossil fuels used for electricity. If so this would be a negative to Cdn natural gas that would be stuck within Western Canada and/or continuing to push into the US when Biden is trying to switch to carbon free electricity. We recognize that there is still some ambiguity in what will be the details of policy and the Liberals aren't changing to no carbon sourced electricity at all. Let's hope so. But let's also be careful that politicians don't change language without a reason or at least with a view to setting up for some future hit. Plus Trudeau had a big warning in that same speech saying "*we will make it law to respect our new 2030 target and achieve net-zero emissions by 2050*". They plan to make it the law that Canada has to be on track for the Liberals 2030 emissions targets. This means that the future messaging will be that the Liberals have no choice but to take harder future emissions actions as it is the law. They will be just obeying the law as they will be obligated to obey the law. Everyone knows the messaging will be we have to do more get to Net Zero, that in itself will inevitably mean it will be the law if he actually does move to eliminate any carbon based electricity. So yes it's a negative, that is unless more Cdn natural gas can be exported via LNG to Asia. We believe this would be a plus to be priced against global LNG instead of Henry Hub.

Biden's global climate summit reminded there is too much risk to skip over natural gas as the transition fuel. Apart from the US and Canada, we haven't seen a sea shift to eliminating natural gas for power generation, especially from energy import dependent countries. There is a strong belief that hydrogen and battery storage will one day be able to scale up at a competitive cost to lead to the acceleration away from fossil fuels. But that time isn't yet here, at least not for energy import dependent countries. One of the key themes from last week's leader's speeches at the Biden global climate summit – to get to Net Zero, the world is assuming there wilt be technological advances/discoveries that aren't here today and that have the potential to immediately ramp up in scale. IEA Executive Director Faith Birol was blunt in his message [LINK] saying "*Right now, the data does not match the rhetoric – and the gap is getting wider*." And "*IEA analysis shows that about half the reductions to get to net zero emissions in 2050 will need to come from technologies that are not yet ready for market. This calls for massive leaps in innovation. Innovation across batteries, hydrogen, synthetic fuels, carbon capture and many other technologies.* US Special Envoy for Climate John Kerry said a similar point that half of the emissions reductions will have to come from technologies that we don't yet have at scale. UK PM Johnson [LINK] didn't say it specifically, but points to this same issue saying "*To do these things we've got to be constantly original and optimistic about new technology and new solutions whether that's crops that are super-resistant to drought or more accurate weather forecasts like those we hope to see from the UK's new Met Office 1.2bn supercomputer that we're investing in*." It may well be that the US and other self sufficient energy countries are comfortable going on the basis of assuming technology developments will occur on a timely basis. But, its clear that countries like China, India, South Korea and others are not prepared to do so. And not prepared to have the confidence to rid themselves of coal power generation. This is why there hasn't been any material change in the LNG demand outlook

We expect the IEA's blunt message that the gap is getting wider will be reinforced on May 18. We have had a consistent view on the energy transition for the past few years. We believe it is going to happen, but it will take longer, be a bumpy road and cost more than expected. This is why we believe the demise of oil and natural gas won't be as easy and fast as hoped for by the climate change side. The IEA's blunt warning on the gap widening should not be a surprise as they warned on this in June 2020. Birol's climate speech also highlighted that the IEA will release on May 18 its roadmap for how the global energy sector can reach net zero by 2050. Our SAF Group June 11, 2020 blog "*Will The Demise Of Oil Take Longer, Just Like Coal? IEA and Shell Highlight Delays/Gaps To A Smooth Clean Energy Transition*" [LINK] feature the IEA's June 2020 warning that the critical energy technologies needed to reduce emissions are nowhere near where they need to be. In that blog, we said "there was an excellent illustration of the many significant areas, or major pieces of the puzzle, involved in an energy transition by the IEA last week. The IEA also noted the progress of each of the major pieces and the overall conclusion is that the vast majority of the pieces are behind or well behind where they should be to meet a smooth timely energy transition. It is important to note that these are just what the IEA calls the "*critical energy technologies*" and does not get into the wide range of other considerations needed to support the energy transition. The IEA divides these "critical energy technologies "into major groupings and then ranked the progress of each of these pieces in its report "*Tracking Clean Energy Progress*" [LINK] by on track, more efforts needed, or not on track". Our blog included the below IEA June 2020 chart.

IEA's Progress Ranking For "Critical Energy Technologies" For Clean Energy Transition

Power	Renewable Power	Geothermal
	Solar PV	Ocean Power
	Onshore Wind	Nuclear Power
	Offshore Wind	Natural Gas-Fired Power
	Hydropower	Coal-Fired Power
	Bioenergy Power Generation	CCUS in Power
	Concentrating Solar Power	
Fuel Supply	Methane Emissions from O&G	Flaring Emissions
Industry	Chemicals	Pulp and Paper
	Iron and Steel	Aluminum
	Cement	CCUS in Industry and Transformation
Transport	Electric Vehicles	Transport Biofuels
	Rail	Aviation
	Fuel Consumption of Cars and Vans	International Shipping
	Trucks and Busses	
Buildings	Building Envelopes	Lighting
	Heating	Appliances and Equipment
	Heat Pumps	Data Centres and Data Transmission Networks
	Cooling	
Energy Integration	Energy Storage	Demand Response
	Hydrogen	Direct Air Capture
	Smart Grids	

Source: IEA

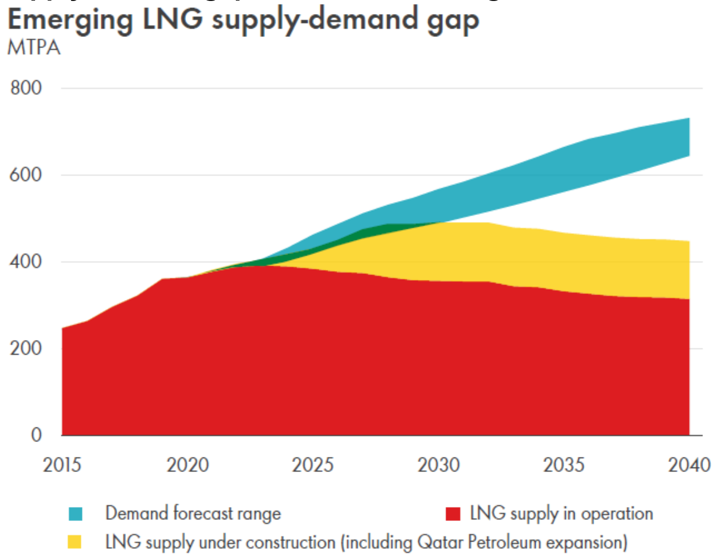
On Track More Efforts Needed Not on Track

Source: IEA Tracking Clean Energy Progress, June 2020

We are referencing Shell's long term outlook for LNG We recognize there are many different forecasts for LNG, but are referencing Shell' LNG Outlook 2021 from Feb 25, 2021 for a few reasons. (i) Shell's view on LNG is the key view for when and what decision will be made for LNG Canada Phase 2. (ii) Shell is one of the global leaders in LNG supply and trading. (iii) Shell provides on the record LNG outlooks every year so there is the ability to compare and make sure the outlook fits the story. It does. (iv) Shell, like other supermajors, has had to make big capex cuts post pandemic and that certainly wouldn't put any bias to the need for more capex.

Shell's March 2021 long term outlook for LNG demand was basically unchanged vs 2020 and leads to a LNG supply gap in mid 2020s Shell does not provide the detailed numbers in their Feb 25, 2021 LNG forecast. We would assume they would have reflected some delay, perhaps 1 year, at Mozambique but would be surprised if they put a 2-3 year delay in for the 5 bcf/d from Total Phase 1 +2 and Exxon Rozuma Phase 1. Compared to their LNG Outlook 2020, it looks like there was no change for their estimate of global natural gas demand growth to 2040, which looked relatively unchanged at approx. 5,000 bcm/yr or 484 bcf/d. Similarly, long term LNG demand looked unchanged to 2040 of ~700 mm tonnes (92 bcf/d) vs 360 mm tonnes (47 bcf/d) in 2020. In the 2021 outlook, Shell highlighted that the pandemic delayed project construction timelines and that the "*lasting impact expected on LNG supply not demand*". And that Shell sees a LNG "*supply-demand gap estimated to emerge in the middle of the current decade as demand rebounds*". Comparing to 2020, it looks like the supply-demand gap is sooner.

Supply-demand gap estimated to emerge in the middle of the current decade



Source: Shell LNG Outlook 2021, Feb 25, 2021

<u>Mozambique delays are redefining the LNG markets for the 2020s: Delaying 5 bcf/d of Mozambique new LNG supply 2-3 years means a much bigger supply gap starting in 2025..</u> Even if the optimists are right, there are now delays to all major Mozambique LNG supply from LNG supply forecasts. We don't have the detail, but we believe all LNG forecasts, including Shell's LNG Outlook 2021, would have included Total's Phase 1 and Phase 2 and Exxon Rozuma Phase 1. As noted earlier, we believe that the likely impact of the Mozambique security concerns is that these forecasts would likely have to push back 1.7 bcf/d from Total Phase 1 to at least 2026, 2.0 bcf/d Exxon Rozuma Phase 1 to at least 2027, and 1.3 bcf/d Total Phase 2 to at least 2028/2029 with the real risk these get pushed back even further. 5.0 bcf/d is equal to 38 mtpa. These delays would mean there is an increasing LNG supply gap in 2025 and increasingly significantly thereafter. And even if a new greenfield LNG project is FID's right away, it wouldn't be able to step in to replace Total Phase 1 prior startup timing for 2024 or likely the market at all until at least 2027. Its why the decision on filling the gap will fall on brownfield LNG projects.

<u>And does this bigger, nearer supply gap force LNG players to look at what brownfield LNG projects they could advance?</u> A greenfield LNG project would likely take at least until 2027 to be in operations. Its why we believe the Mozambique delays will effectively force major LNG players to look to see if there are brownfield LNG projects they should look to advance. Prior to the just passed winter, no one would think Shell or other major LNG players would be considering any new LNG FIDs in 2021. All the big companies are in capital reduction mode and debt reduction mode. But Brent oil is now solidly over $60 and LNG prices hit record levels in Jan and the world's economic and oil and gas demand outlook are increasing with vaccinations. And we are starting to see companies move to increasing capex with the higher cash flows. We would not expect any major LNG players to move to FID right away. But we see them watching to see if 2021 plays out to still support this increasing LNG supply gap. And unless new mutations prevent vaccinations from returning the world to normal, we suspect that major LNG players, like other oil and gas companies, will be looking to increase

capex as they approve 2022 budgets. The outlook for the future has changed dramatically in the last 5 months. The question facing Shell and others, should they look to FID new LNG brownfield projects in the face of an increasing LNG supply gap that is going to hit faster and harder than expected a few months ago. We expect these decisions to be looked at before the end of 2021. LNG prices will be stronger, but we expect the limiting cap in Asia will be that thermal coal will be used to mitigate some LNG price pressure.

Back to Shell, does increasing LNG supply gap provide the opportunity to at least consider a LNG Canada Phase 2 FID over the next 9 months? Shell is no different than any other major LNG supplier in always knowing the market and that the oil and gas outlook is much stronger than 6 months ago. No one has been or is talking about this Mozambique impact and how it will at least force major LNG players to look at if they should FID new brownfield LNG projects to take advantage of this increasing supply gap. We don't have any inside contacts at Shell or LNG Canada, but that is no different than when we looked at the LNG markets in September 2017 and saw the potential for Shell to FID LNG Canada in 2018. We posted a September 20, 2017 blog *"China's Plan To Increase Natural Gas To 10% Of Its Energy Mix Is A Global Game Changer Including For BC LNG"* [LINK]. Last time, it was a demand driven supply gap, this time, it's a supply driven supply gap. We have to believe any major LNG player, including Shell, will be at least looking at their brownfield LNG project list and seeing if they should look to advance FID later in 2021. Shell has LNG Canada Phase 2, which would add 2 additional trains or approx. 1.8 bcf/d. And an advantage to an FID would be that Shell would be able to commit to its existing contractors and fabricators for a continuous construction cycle following on LNG Canada Phase 1 ie. to help keep a lid on capital costs. No one is talking about the need for these new brownfield LNG projects, but, unless Total gets back developing Mozambique and keeps the delay to a matter of months, its inevitable that these brownfield LNG FID internal discussions will be happening in H2/21. Especially since the oil and gas price outlook is much stronger than it was in the fall and companies will be looking to increase capex in 2022 budgets

A LNG Canada Phase 2 would be a big plus to Cdn natural gas. A LNG Canada Phase 2 FID would be a big plus for Cdn natural gas. It would allow another ~1.8 bcf/d of Cdn natural gas to be priced against Asian LNG prices and not against Henry Hub. And it would provide demand offset versus Trudeau if he moves to make electricity "emissions free" and not his prior "net zero emissions". Mozambique may be in Africa, but, unless sustained peace and security is attained, it is a game changer to LNG outlook creating a bigger and sooner LNG supply gap. And with a stronger tone to oil and natural gas prices in 2021, the LNG supply gap will at least provide the opportunity for Shell to consider FID for its brownfield LNG Canada Phase 2 and provide big support to Cdn natural gas for back half of the 2020s. And perhaps if LNG Canada is exporting 3.6 bcf/d from two phases, it could help flip Cdn natural gas to a premium to US natural gas especially if Biden is successful in reducing US domestic natural gas consumption for electricity. The next six months will be very interesting to watch for LNG markets.

https://lngir.cheniere.com/news-events/press-releases/detail/231/cheniere-and-enn-sign-long-term-lng-sale-and-purchase

Cheniere and ENN Sign Long-Term LNG Sale and Purchase Agreement

OCTOBER 11, 2021 8:30AM EDT

HOUSTON--(BUSINESS WIRE)-- Cheniere Energy, Inc. ("Cheniere" or the "Company") (NYSE American: LNG) announced today that its subsidiary, Cheniere Marketing, LLC ("Cheniere Marketing"), has entered into a liquefied natural gas ("LNG") sale and purchase agreement ("SPA") with ENN LNG (Singapore) Pte Ltd ("ENN LNG"), a wholly-owned subsidiary of ENN Natural Gas Co., Ltd. ("ENN Natural Gas").

Under the SPA, ENN LNG has agreed to purchase approximately 0.9 million tonnes per annum of LNG from Cheniere Marketing on a free-on-board basis for a term of approximately 13 years beginning in July 2022. The purchase price for LNG under the SPA is indexed to the Henry Hub price, plus a fixed liquefaction fee. ENN Natural Gas is acting as guarantor of the SPA.

"We are pleased to announce this long-term LNG contract with ENN, a major player in China's rapidly growing natural gas market, and we look forward to a successful, long-term relationship with ENN as a customer," said Jack Fusco, Cheniere's President and Chief Executive Officer. "This SPA underscores the strength of the global LNG market today, particularly in China, and highlights Cheniere's role as a leading global LNG supplier, tailoring solutions to help meet the long-term energy needs and environmental goals of our customers. The SPA also further advances Cheniere's commercial momentum and marks another milestone in our efforts to contract our LNG capacity on a long-term basis in anticipation of an FID of Corpus Christi Stage 3, which we expect will occur next year."

Wang Yusuo, Chairman of the Board of ENN Natural Gas said, "China is making great efforts to achieve the goal of peak carbon emissions and carbon neutrality, boosting the reform of the natural gas market, and accelerating the structural adjustment of energy consumption. As one of the world's leading LNG suppliers, Cheniere has great advantages on resource production and supply capacity, which is highly compatible with the fast-growing natural gas market in China. ENN is accelerating the usage of digital technology to build a modern energy system, and to promote intelligent upgrading of the natural gas industry. It is expected that the two parties will seize the opportunity of this cooperation to establish a strategic relationship, to provide clients with high quality resources and services, and to make positive efforts to the realization of peak carbon emissions and carbon neutrality in China."

About Cheniere

Cheniere Energy, Inc. is the leading producer and exporter of liquefied natural gas (LNG) in the United States, reliably providing a clean, secure, and affordable solution to the growing global need for natural gas. Cheniere is a full-service LNG provider, with capabilities that include gas procurement and transportation, liquefaction, vessel chartering, and LNG delivery. Cheniere has one of the largest liquefaction platforms in the world, consisting of the Sabine Pass and Corpus Christi liquefaction facilities on the U.S. Gulf Coast, with expected total production capacity of approximately 45 million tonnes per annum of LNG operating or under construction. Cheniere is also pursuing liquefaction expansion opportunities and other projects along the LNG value chain. Cheniere is headquartered in Houston, Texas, and has additional offices in London, Singapore, Beijing, Tokyo, and Washington, D.C.

For additional information, please refer to the Cheniere website at www.cheniere.com and Quarterly Report on Form 10-Q for the quarter ended June 30, 2021, filed with the Securities and Exchange Commission.

About ENN Natural Gas

As one of the largest private energy companies in China, ENN Natural Gas' business layout covers the entire natural gas industry including distribution, trade, storage & transportation, production and construction. As of 30 June 2021, through its subsidiary, ENN Energy Holdings Limited, one of the largest natural gas distribution companies in China, ENN Natural Gas owns 239 city-gas projects in China, with a connectable population of 117 million. ENN Natural Gas operates the Zhoushan LNG regasification facility in Zhejiang Province, China. During 1H 2021, ENN Natural Gas's total natural gas sales volume was 17.5 bcm, accounting for 9.6% of China's total consumption.

Asian LNG Buyers Abruptly Change and Lock in Long Term Supply – Validates Supply Gap, Provides Support For Brownfield LNG FIDs

Posted 11am on July 14, 2021

The last 7 days has shown there is a sea change as Asian LNG buyers have made an abrupt change in their LNG contracting and are moving to lock in long term LNG supply. This is the complete opposite of what they were doing pre-Covid when they were trying to renegotiate Qatar LNG long term deals lower and moving away from long term deals to spot/short term sales. Why? We think they did the same math we did in our April 28 blog "*Multiple Brownfield LNG FIDs Now Needed To Fill New LNG Supply Gap From Mozambique Chaos? How About LNG Canada Phase 2?*" and saw a much bigger and sooner LNG supply gap driven by the delay of 5 bcf/d of Mozambique LNG that was built into most, if not all LNG supply forecasts. Asian LNG buyers are committing real dollars to long term LNG deals, which we believe is the best validation for the LNG supply gap. Another validation, Shell, Total and others are aggressively competing to invest long term capital to partner in Qatar Petroleum's massive 4.3 bcf/d LNG expansion despite plans to reduce fossil fuels production in the 2020s. And even more importantly to LNG suppliers, the return to long term LNG contracts provides the financing capacity to commit to brownfield LNG FIDs. The abrupt change by Asian LNG buyers to long term contracts is a game changer for LNG markets and sets the stage for brownfield LNG FIDs likely as soon as before year end 2021. It has to be brownfield LNG FIDs if the gap is coming bigger and sooner. And we return to our April 28 blog point, if brownfield LNG is needed, what about Shell looking at 1.8 bcf/d brownfield LNG Canada Phase 2? LNG Canada Phase 1 at 1.8 bcf/d capacity is already a material positive for Cdn natural gas producers. A FID on LNG Canada Phase 2 would be huge, meaning 3.6 bcf/d of Cdn natural gas will be tied to Asian LNG markets and not competing in the US against Henry Hub. And with a much shorter distance to Asian LNG markets. This is why we focus on global LNG markets for our views on the future value of Canadian natural gas.

<u>Sea change in Asian LNG buyers is also the best validation of the LNG supply gap and big to LNG supply FIDs.</u> Has the data changed or have the market participants changed in how they react to the data? We can't recall exactly who said that on CNBC on July 12, it's a question we always ask ourselves. In the LNG case, the data has changed with Mozambique LNG delays and that has directly resulted in market participants changing and entering into long term contracts. We can't stress enough how important it is to see Asian LNG buyers move to long term LNG deals. (i) Validates the sooner and bigger LNG supply gap. We believe LNG markets should look at the last two weeks of new long term deals for Asian LNG buyers as being the validation of the LNG supply gap that clearly emerged post Total declaring force majeure on its 1.7 bcf/d Mozambique LNG Phase 1 that was under construction and on track for first LNG delivery in 2024. Since then, markets have started to realize the Mozambique delays are much more than 1.7 bcf/d. They have seen major LNG suppliers change their outlook to a more bullish LNG outlook and, most importantly, are now seeing Asian LNG buyers changing from trying to renegotiate long term LNG deals lower to entering into long term LNG deals to have security of supply. Asian LNG buyers are cozying up to Qatar in a prelude to the next wave of Asian buyer long term deals. What better validation is there than companies/countries putting their money where their mouth is. (ii) Provides financial commitment to help push LNG suppliers to FID. We believe these Asian LNG buyers are doing much more than validating a LNG supply gap to markets. The big LNG suppliers can move to FID based on adding more LNG supply to their portfolio, but having more long term deals provides the financial anchor/visibility to long term capital commitment from the buyers. Long term contracts will only help LNG suppliers get to FID.

<u>It was always clear that the Mozambique LNG supply delay was 5.0 bcf/d, not just 1.7 bcf/d from Total Phase 1.</u> LNG markets didn't really react to Total's April 26 declaration of force majeure on its 1.7 bcf/d Mozambique LNG Phase 1. This was an under construction project that was on time to deliver first LNG in 2024. It was in all LNG supply forecasts. There was no timeline given but, on the Apr 29 Q1 call, Total said that it expected any restart decision would be least a year away. If so, we believe that puts any actual construction at least 18 months away. There will be work to do just to get back to where they were when they were forced to stop development work on Phase 1. Surprisingly, markets didn't look the broader implications, which is why we posted our 7-pg Apr 28 blog "*Multiple Brownfield LNG FIDs Now Needed To Fill New LNG Supply Gap From Mozambique Chaos? How About LNG Canada Phase 2?*" [LINK] We highlighted that Mozambique LNG delays were actually 5 bcf/d, not 1.7 bcf/d. And this 5 bcf/d of Mozambique LNG supply was built into most, if not all, LNG supply forecasts. The delay in Total Phase 1 would lead to a commensurate delay in its Mozambique LNG Phase 2 of 1.3 bcf/d. Total Phase 2 was to add 1.3 bcf/d. There was no firm in service date, but it was expected to

follow closely behind Phase 1 to maintain services. That would have put it originally in the 2026/2027 period. But if Phase 1 is pushed back at least 2 years, so will the follow on Phase 2, so more likely, it will be at least 2028/2029. The assumption for most, if not all, LNG forecasts was that Phase 2 would follow Phase 1. Exxon Rozuma Phase 1 of 2.0 bcf/d continues to be pushed back in timeline especially following Total Phase 1. Exxon's Mozambique Rozuma Phase 1 LNG will add 2.0 bcf/d and, pre-Covid, was originally expected to be in service in 2025. The project was being delayed and Total's force majeure has added to the delays. Rozuma onshore LNG facilities are right by Total. On June 20, we tweeted [LINK] on the Reuters report "*Exclusive: Galp says it won't invest in Rovuma until Mozambique ensures security*" [LINK]. Galp is one of Exxon's partners in Rozuma. Reuters reported that Galp said they won't invest in Exxon's Rozuma LNG project until the government ensures security, that this may take a while, they won't be considering the project until after Total has reliably resumed work on its Phase 1, which likely puts any Rozuma decision until at least end of 2022 at the earliest. Galp has taken any Rozuma Phase 1 capex out of their new capex plans thru 2025 and will have to take out projects in their capex plan if Rozuma does come back to work. This puts Rozuma more likely 2028 at the earliest as opposed to before the original expectations of before 2025. Pre-pandemic, Exxon's March 6, 2019 Investor Day noted their operated Mozambique Rovuma LNG Phase 1 was to be 2 trains each with 1.0 bcf/d capacity for total initial capacity of 2.0 bf/d with FID expected in 2019 and first LNG deliveries sometime before 2025. LNG forecasts had been assuming Exxon Rozuma would be onstream around 2025. The 2019 FID expectation was later pushed to be expected just before the March 2020 investor day. But the pandemic hit, and on March 21, 2020, we tweeted [LINK] on the Reuters story "*Exclusive: Coronavirus, gas slump put brakes on Exxon's giant Mozambique LNG plan*" [LINK] that noted Exxon was expected to delay the Rovuma FID. There was no timeline, but now, any FID is not expected until late 2022 at the earliest, that would push first LNG likely to at least 2028. What this means is that the Mozambique LNG delays are not 1.7 bcf/d but 5.0 bcf/d of projects that were in all, if not most, LNG supply forecasts. There is much more in our 7-pg blog. But Mozambique is what is driving a much bigger and sooner LNG supply gap starting ~2025 and stronger outlook for LNG prices

One of the reasons why it went under the radar is that major LNG suppliers played stupid on the Mozambique impact. It makes it harder for markets to see a big deal when the major LNG suppliers weren't making a big deal of Mozambique or playing stupid in the case of Cheniere in their May 4 Q1 call. In our May 9, 2021 Energy Tidbits memo, we said we had to chuckle when we saw Cheniere's response in the Q&A to its Q1 call on May 4 that they only know what we know from reading the Total releases on Mozambique and its impact on LNG markets. It's why we tweeted [LINK] "*Hmm! $LNG says only know what we read on #LNG market impact from $TOT $XOM MZ LNG delays*. *Surely #TohokuElectric & other offtake buyers are reaching out to #Cheniere. MZ LNG delays is a game changer to LNG in 2020s, see SAF Group blog. Thx @olympe_mattei @TheTerminal #NatGas".* How could they not be talking to LNG buyers for Total and /or Exxon Mozambique LNG projects. In the Q1 Q&A, mgmt was asked about Mozambique and didn't know any more than what you or I have read. Surely, they were speaking to Asian LNG buyers who had planned to get LNG supply from Total Mozambique or Exxon Rozuma Mozambique or both. Mgmt is asked "*wanted to just kind of touch on the color use talking about for these supply curve. And are you able to kind of provide any thoughts on the Mozambique and a deferral with the project of that size on 13 and TPA being deferred by we see you have you noticed any impact to the market has is there any impact for stage 3 with that capacity? Thanks*." Mgmt replies "*No. Look, I only know about the Mozambique delay with what I read as well as what you read that from total and an Exxon. And it's a sad situation and I hope everybody is safe and healthy that were there to experience that unrest but no I don't think it's, again it's a different business paradigm than what we offer. So, we offer a full value product, the customer doesn't have to invest in equity, customer doesn't have to worry about the E&P side of the business because, we've been able to both the by at our peak almost 7 Dee's a day of US NAT gas from almost a 100 different producers on 26 different pipelines and deliver it to our to facilities. So we take care of a lot of what the customer needs".*

There are other LNG supply delays/interruptions beyond Mozambique. There have been a number of other smaller LNG delay or existing supply interruptions that add to Asian LNG buyers feeling less secure about the reliability of mid to long term LNG supply. Here are just a few examples. (i) Total Papua LNG 0.74 bcf/d. On June 8, we tweeted [LINK] *"Timing update Papua #LNG project. $OSH June 8 update "2022 FEED, 2023 FID targeting 2027 first gas". $TOT May 5 update didn't forecast 1st gas date. Papua is 2 trains w/ total capacity 0.74 bcf/d."* We followed the tweet saying [LINK] *"Bigger #LNG supply gap being created >2025. Papua #LNG originally expected FID in 2020 so 1st LNG is 2 years delayed.*

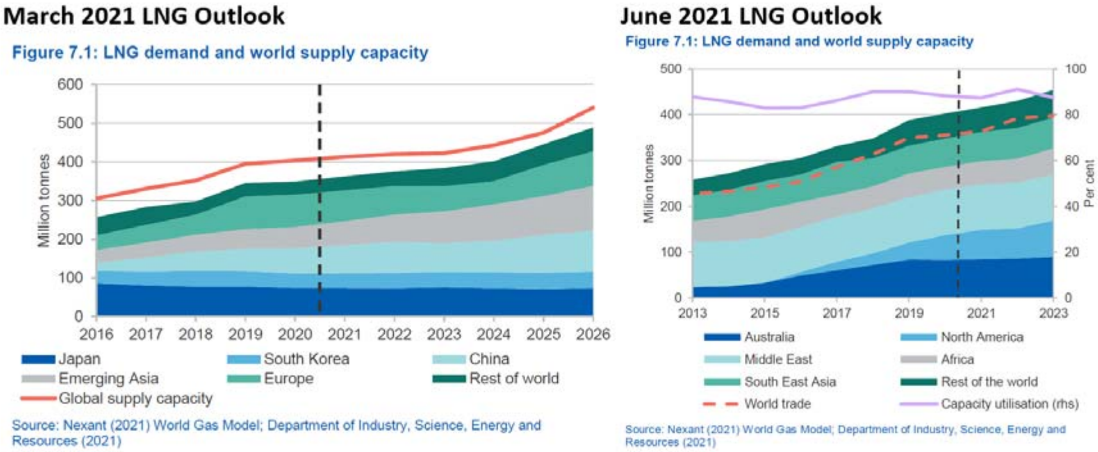
Common theme - new LNG supply is being delayed ie. [Total] Mozambique. Don't forget need capacity>demand due to normal maintenance, etc. Positive for LNG." (ii) Chevron's Gorgon. A big LNG story in H2/20 was the emergence of weld quality issues in the propane heat exchangers at Train 2, which required additional downtime for repair. Train 2 was shut on May 23 with an original restart of July 11, but the repairs to the weld quality issues meant it didn't restart until late Nov. The same issue was found in Train 1 but repairs were completed. However extended downtime for the trains led to lower LNG volumes. Gorgon produced ~2.3 bcf/d in 2019 but was down to 2.0 bcf/d in 2020. (iii) Equinor's Melkoeya 0.63 bcf/d shut down for 18 months due to a fire. A massive fire led to the Sept 28, 2020 shutdown of the 0.63 bcf/d Melkoeya LNG facility in Norway. On April 26, Equinor released "*Revised start-up date for Hammerfest LNG*" [LINK] with regard to the 0.63 bcf/d Melkoeya LNG facility. The original restart date was Oct 1, 2021 (ie. a 12 month shut down), but Equinor said "*Due to the comprehensive scope of work and Covid-19 restrictions, the revised estimated start-up date is set to 31 March 2022*". When we read the release, it seemed like Equinor was almost setting the stage for another potential delay in the restart date. Equinor had two qualifiers to this March 31, 2022 restart date. Equinor said "*there is still some uncertainty related to the scope of the work*" and "*Operational measures to handle the Covid-19 situation have affected the follow-up progress after the fire. The project for planning and carrying out repairs of the Hammerfest LNG plant must always comply with applicable guidelines for handling the infection situation in society. The project has already introduced several measures that allow us to have fewer workers on site at the same time than previously expected. There is still uncertainty related to how the Covid-19 development will impact the project progress."*

<u>Cheniere stopped the game playing the game on June 30</u>. Our July 4, 2021 Energy Tidbits memo noted that it looks like Cheniere has stopped playing stupid with respect to the strengthening LNG market in 2021. We can't believe they thought they were fooling anyone, especially their competitors. Bu that week, they came out talking about how commercial discussions have picked up in 2021 and it's boosted their hope for a Texas (Corpus Christi) LNG expansion. On Wednesday, Platts reported "*Pickup in commercial talks boosts Cheniere's hopes on mid-scale LNG project*" [LINK] Platts wrote "*Cheniere Energy expects to make a "substantial dent" by the end of 2022 in building sufficient buyer support for a proposed mid-scale expansion at the site of its Texas liquefaction facility, Chief Commercial Officer Anatol Feygin said June 30 in an interview." " As a result, he said, " The commercial engagement, I think it is very fair to say, has really picked up steam, and we are quite optimistic over the coming 12-18 months to make a substantial dent in that Stage 3 commercialization."* Platts also reported that Cheniere noted this has been a tightening market all year (ie would have been known by the May 4 Q1 call). Platts wrote "*We obviously find ourselves at the beginning of this year and throughout in a very tight market where prices today into Asia and into Europe are at levels that we frankly haven't seen in a decade-plus," Feygin said. "We've surpassed the economics that the industry saw post the Fukushima tragedy in March 2011, and that's happened in the shoulder period."* It's a public stance as to a more bullish LNG outlook

<u>But we still see major LNG suppliers like Australia hinting but not outright saying that LNG supply gap is coming sooner.</u> We have to believe Australia will be unveiling a sooner LNG supply gap in their September forecast. On June 28, we tweeted [LINK] on Australia's Resources and Energy Quarterly released on Monday [LINK] because there was a major change to their LNG outlook versus their March forecast. We tweeted "*#LNGSupplyGap. AU June fcast now sees #LNG mkt tighten post 2023 vs Mar fcast excess supply thru 2026. Why? $TOT Mozambique delays. See below SAF Apr 28 blog. Means brownfield LNG FID needed ie. like #LNGCanada Phase 2. #OOTT #NatGas"*. Australia no longer sees supply exceeding demand thru 2026. In their March forecast, Australia said "*Nonetheless, given the large scale expansion of global LNG capacity in recent years, demand is expected to remain short of total supply throughout the projection period."* Note this is thru 2026 ie. a LNG supply surplus thru 2026. But on June 28, Australia changed that LNG outlook and now says the LNG market may tighten beyond 2023. Interestingly, the June forecast only goes to 2023 and not to 2026 as in March. Hmmm! On Monday, they said "*Given the large scale expansion of global LNG capacity in recent years, import demand is expected to remain short of export capacity throughout the outlook period. Beyond 2023, the global LNG market may tighten, due to the April 2021 decision to indefinitely suspend the Mozambique LNG project, in response to rising security issues. This project has an annual nameplate capacity of 13 million tonnes, and was previously expected to start exporting LNG in 2024*." 13 million tonnes is 1.7 bcf/d so they are only referring to Total Mozambique LNG Phase 1. So no surprise the change is Mozambique LNG driven but we have to believe the reason why they cut their forecast off this time at 2023 is that they are looking at trying to figure out what to forecast beyond 2023 in addition to Total Phase 1. And, importantly, we believe they will be changing their LNG forecast for more than Mozambique ie. India

demand that we highlight later in the blog. They didn't say anything else specific on Mozambique but, surely they have to also be delaying the follow on Total Phase 2 of 1.3 bcf/d and Exxon Rozuma Phase 1 of 2.0 bcf/d.

Australia's LNG Outlook: March 2021 vs June 2021 Forecasts

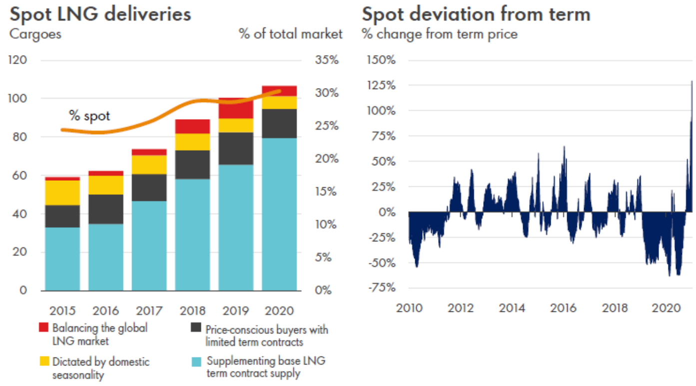


Source: Australia Resources and Energy Quarterly

Clearly Asian LNG buyers did the math, saw the new LNG supply gap and were working the phones in March/April/May trying to lock up long term supply. We wrote extensively on the Total Mozambique LNG situation before the April 26 force majeure as it was obvious that delays were coming to a project counted on for first LNG in 2024. Total had shut down Phase 1 development in December for 3 months due to the violence and security risks. It restarted development on Wed March 24, violence/attacks immediately resumed for 3 consecutive days, and then Total suspended development on Sat March 27. That's why no one should have been surprised by the April 26 force majeure. Asian LNG buyers were also seeing this and could easily do the same math we were doing and saw a bigger and sooner LNG supply gap. They were clearly working the phones with a new priority to lock up long term LNG supply. Major long term deals don't happen overnight, so it makes sense that we started to see these new Asian long term LNG deals start at the end of June.

A big pivot from trying to renegotiate down long term LNG deals or being happy to let long term contracts expire and replace with spot/short term LNG deals. This is a major pivot or abrupt turn on the Asian LNG buyers contracting strategy for the 2020s. There is the natural reduction of long term contracts as contracts reach their term. But with the weakness in LNG prices in 2019 and 2020, Asian LNG buyers weren't trying to extend long term contracts, rather, the push was to try to renegotiate down its long term LNG deals. The reason was clear, as spot prices for LNG were way less than long term contract prices. And this led to their LNG contracting strategy – move to increase the proportion of spot LNG deliveries out of total LNG deliveries. Shell's LNG Outlook 2021 was on Feb 25, 2021 and included the below graphs. The spot LNG price derivation from long term prices in 2019 and 2020 made sense for Asian LNG buyers to try to change their contract mix. Yesterday, Maeil Business News Korea reported on the new Qatar/Kogas long term LNG deal with its report "*Korea may face LNG supply cliff or pay hefty price after long-term supplies run out*" [LINK], which highlighted this very concept – Korea wasn't worried about trying to extend expiring long term LNG contracts. Maeil wrote "*Seoul in 2019 secured a long-term LNG supply contract with the U.S. for annual 15.8 million tons over a 15-year period. But even with the latest two LNG supply contracts, the Korean government needs extra 6 million tons or more of LNG supplies to keep up the current power pipeline. By 2024, Korea's long-term supply contracts for 9 million tons of LNG will expire - 4.92 million tons on contract with Qatar and 4.06 million tons from Oman, according to a government official who asked to be unnamed.*"

Spot LNG deliveries and Spot deviation from term price



Source: Shell LNG Outlook 2021 on Feb 25, 2021

Asian LNG buyers moving to long term LNG deals provide financing capacity for brownfield LNG FIDs. We believe this abrupt change and return to long term LNG deals is even more important to LNG suppliers who want to FID new projects. The big LNG players like Shell can FID new LNG supply without new long term contracts as they can build into their supply options to fill their portfolio of LNG contracts. But that doesn't mean the big players don't want long term LNG supply deals, as having long term LNG contracts provide better financing capacity for any LNG supplier. It takes big capex for LNG supply and long term deals make the financing easier.

Four Asian buyer long term LNG deals in the last week. It was pretty hard to miss a busy week for reports of new Asian LNG buyer long term LNG deals. There were two deals from Qatar Petroleum, one from Petronas and one from BP. The timing fits, it's about 3 months after Total Mozambique LNG problems became crystal clear. And as noted later, there are indicators that more Asian buyer LNG deals are coming.

Petronas/CNOOC is 10 yr supply deal for 0.3 bcf/d. On July 7, we tweeted [LINK] on the confirmation of a big positive to Cdn natural gas with the Petronas announcement [LINK] of a new 10 year LNG supply deal for 0.3 bcf/d with China's CNOOC. The deal also has special significance to Canada. (i) Petronas said "*This long-term supply agreement also includes supply from LNG Canada when the facility commences its operations by middle of the decade*". This is a reminder of the big positive to Cdn natural gas in the next 3 to 4 years – the start up of LNG Canada Phase 1 is ~1.8 bcf/d capacity. This is natural gas that will no longer be moving south to the US or east to eastern Canada, instead it will be going to Asia. This will provide a benefit for all Western Canada natural gas. (ii) First ever AECO linked LNG deal. It's a pretty significant event for a long term Asia LNG deal to now have an AECO link. Petronas wrote "*The deal is for 2.2 million tonnes per annum (MTPA) for a 10-year period, indexed to a combination of the Brent and Alberta Energy Company (AECO) indices. The term deal between PETRONAS and CNOOC is valued at approximately USD 7 billion over ten years.*" 2.2 MTPA is 0.3 bcf/d. (iii) Reminds of LNG Canada's competitive advantage for low greenhouse gas emissions. Petronas said "*Once ready for operations, the LNG Canada project paves the way for PETRONAS to supply low greenhouse gas (GHG) emission LNG to the key demand markets in Asia.*"

Qatar Petroleum/CPC (Taiwan) is 15 yr supply deal for 0.16 bcf/d. Pre Covid, Qatar was getting pressured to renegotiate lower its long term LNG contract prices. Now, it's signing a 15 year deal. On July 9, they entered in a new small long term LNG sales deal [LINK], a 15-yr LNG Sale and Purchase Agreement with CPC Corporation in Taiwan to supply it ~0.60 bcf/d of LNG. LNG deliveries are set to begin in January 2022. H.E. Minister for Energy Affairs & CEO of Qatar Petroleum Al-Kaabi said *"We are pleased to enter into this long term LNG SPA, which is another milestone in our relationship with CPC, which dates back to almost three decades. We look forward to commencing deliveries under this SPA and to continuing our supplies as a trusted and reliable global LNG provider."* The pricing was reported to be vs a basket of crudes.

BP/Guangzhou Gas, a 12-yr supply deal for 0.13 bcf/d. On July 9, there was a small long term LNG supply deal with BP and Guangzhou Gas (China). Argus reported [LINK] BP had signed a 12 year LNG supply deal with Guangzhou Gas (GG), a Chinese city's gas distributor, which starts in 2022. The contract prices are to be linked to an index of international crude prices. Although GG typically gets its LNG from the spot market, it used a tender in late April for ~0.13 bcf/d starting in 2022. BP's announcement looks to be for most of the tender, so it's a small deal. But it fit into the trend this week of seeing long term LNG supply deals to Asia. This was intended to secure deliveries to the firm's Xiaohudao import terminal which will become operational in August 2022.

Qatar/Korea Gas is a 20-yr deal to supply 0.25 bcf/d. On Monday, Reuters reported [LINK] "*South Korea's energy ministry said on Monday it had signed a 20-year liquefied natural gas (LNG) supply agreement with Qatar for the next 20 years starting in 2025. South Korea's state-run Korea Gas Corp (036460.KS) will buy 2 million tonnes of LNG annually from Qatar Petroleum".* There was no disclosure of pricing.

More Asian buyer long term LNG deals (ie. India) will be coming. There are going to be more Asian buyer long term LNG deals coming soon. Our July 11, 2021 Energy Tidbits highlighted how India's new petroleum minister Hardeep Singh Puri (appointed July 8) hit the ground running with what looks to be a priority to set the stage for more India long term LNG deals with Qatar. On July 10, we retweeted [LINK] "*New India Petroleum Minister hits ground running. What else w/ Qatar but #LNG. Must be #Puri setting stage for long term LNG supply deal(s). Fits sea change of buyers seeing #LNGSupplyGap (see SAF Apr 28 blog http://safgroup.ca) & wanting to tie up LNG supply. #OOTT".* It's hard to see any other conclusion after seeing what we call a sea change in LNG buyer mentality with a number of long term LNG deals this week. Puri tweeted [LINK] "*Discussed ways of further strengthening mutual cooperation between our two countries in the hydrocarbon sector during a warm courtesy call with Qatar's Minister of State for Energy Affairs who is also the President & CEO of @qatarpetroleum HE Saad Sherida Al-Kaabi".* As noted above, we believe there is a sea change in LNG markets that was driven by the delay in 5 bcf/d of LNG supply from Mozambique (Total Phase 1 & Phase 2, and Exxon Rozuma Phase 1) that was counted on all LNG supply projections for the 2020s. Puri's tweet seems to be him setting the stage for India long term LNG supply deals with Qatar.

Supermajors are aggressively competing to commit 30+ year capital to Qatar's LNG expansion despite stated goal to reduce fossil fuels production. It's not just Asian LNG buyers who are now once again committing long term capital to securing LNG supply, it's also supermajors all bidding to be able to commit big capex to part of Qatar Petroleum's 4.3 bcf/d LNG expansion. Qatar Petroleum received a lot of headlines following the their June 23 announcement on its LNG expansion [LINK] on how they received bids for double the equity being offered. And there were multiple reports that these are on much tougher terms for Qatar's partners. Qatar Petroleum CEO Saad Sherida Al-Kaabi specifically noted that, among the bidders, were Shell, Total and Exxon. Shell and Total have two of the most ambitious plans to reduce fossil fuels production in the 2020's, yet are competing to allocate long term capital to increase fossil fuels production. And Shell and Total are also two of the global LNG supply leaders. It has to be because they are seeing a bigger and sooner LNG supply gap.

Remember Qatar's has a massive expansion but India alone needs 3x the Qatar expansion LNG capacity. In addition to the competition to be Qatar Petroleum's partners, we remind that, while this is a massive 4.3 bcf/d LNG expansion, India alone sees its LNG import growing by ~13 bcf/d to 2030. The Qatar announcement reminded they see a LNG supply gap and continued high LNG prices. We had a 3 part tweet. (i) First, we highlighted [LINK] "*1/3. #LNGSupplyGap coming. big support for @qatarpetroleum expansion to add 4.3 bcf/d LNG. but also say "there is a lack of investments that could cause a significant shortage in gas between 2025-2030" #NatGas #LNG".* This is after QPC accounts for their big LNG expansion. The QPC release said "*However, His Excellency Al-Kaabi voiced concern that during the global discussion on energy transition, there is a lack of investment in oil and gas projects, which could drive energy prices higher by stating that "while gas and LNG are important for the energy transition, there is a lack of investments that could cause a significant shortage in gas between 2025-2030, which in turn could cause a spike in the gas market."* (ii) Second, this is a big 4.3 bcf/d expansion, but India alone has 3x the increase in LNG import demand. We tweeted [LINK] "*2/3. Adding 4.3 bcf/d is big, but dwarfed by items like India. #Petronet gave 1st specific forecast for what it means if #NatGas is to be 15%*

of energy mix by 2030 - India will need to increase #LNG imports by ~13 bcf/d. See SAF Group June 20 Energy Tidbits memo." (iii) Third, Qatar's supply gap warning is driven by the lack of investments in LNG supply. We agree, but note that the lack of investment is in great part due to the delays in both projects under construction and in FIDs that were supposed to be done in 2019. We tweeted [LINK] "3*/3. #LNGSupplyGap is delay driven. $TOT Mozambique Phase 1 delay has chain effect, backs up 5 bcf/d. See SAF Group Apr 28 blog Multiple Brownfield LNG FIDs Now Needed To Fill New #LNG Supply Gap From Mozambique Chaos? How About LNG Canada Phase 2? #NatGas*."

Seems like many missed India's first specific LNG forecast to 2030. Our June 20, 2021 Energy Tidbits memo highlighted the first India forecast that we have seen to estimate the required growth in natural gas consumption and LNG imports if India is to meet its target for natural gas to be 15% of its energy mix by 2030. India will need to increase LNG imports by ~13 bcf/d or 3 times the size of the Qatar LNG expansion. Our June 6, 2021 Energy Tidbits noted the June 4 tweet from India's Energy Minister Dharmendra Pradhan [LINK] reinforcing the 15% goal "*We are rapidly deploying natural gas in our energy mix with the aim to increase the share of natural gas from the current 6% to 15% by 2030."* But last week, Petronet CEO AK Singh gave a specific forecast. Reuters report "*LNG's share of Indian gas demand to rise to 70% by 2030: Petronet CEO"* [LINK] included Petronet's forecast if India is to hit its target for natural gas to be 15% of energy mix by 2030. Singh forecasts India's natural gas consumption would increase from current 5.5 bcf/d to 22.6 bcf/d in 2030. And LNG shares would increase from 50% to 70% of natural gas consumption ie. an increase in LNG imports of ~13 bcf/d from just under 3 bcf/d to 15.8 bcf/d in 2030. Singh did not specifically note his assumption for India's natural gas production, but we can back into the assumption that India natural gas production grows from just under 3 bcf/d to 6.8 bcf/d. It was good to finally see India come out with a specific forecast for 2030 natural gas consumption and LNG imports if India is to get natural gas to 15% of its energy mix in 2030. Petronet's Singh forecasts India natural gas consumption to increase from 5.5 bcf/d to 22.6 bcf/d in 2030. This forecast is pretty close to our forecast in our Oct 23, 2019 blog "*Finally, Some Visibility That India Is Moving Towards Its Target For Natural Gas To Be 15% Of Its Energy Mix By 2030*". Here part of what we wrote in Oct 2019. "*It's taken a year longer than we expected, but we are finally getting visibility that India is taking significant steps towards India's goal to have natural gas be 15% of its energy mix by 2030. On Wednesday, we posted a SAF blog [LINK] "Finally, Some Visibility That India Is Moving Towards Its Target For Natural Gas To Be 15% Of Its Energy Mix By 2030".* Our 2019 blog estimate was for India natural gas demand to be 24.0 bcf/d in 2030 (vs Singh's 22.6 bcf/d) and for LNG import growth of +18.4 bcf/d to 2030 (vs Singh's +13 bcf/d). The difference in LNG would be due to our Oct 2019 forecast higher natural gas consumption by 1.4 bcf/d plus Singh forecasting India natural gas production +4 bcf/d to 2030. Note India production peaked at 4.6 bcf/d in 2010.

Bigger, nearer LNG supply gap + Asian buyers moving to long term LNG deals = LNG players forced to at least look at what brownfield LNG projects they could advance and move to FID. All we have seen since our April 28 blog is more validation of the bigger, nearer LNG supply gap. And now market participants (Asian LNG buyers) are reacting to the new data by locking up long term supply. Cheniere noted how the pickup in commercial engagement means they "*are quite optimistic over the coming 12-18 months to make a substantial dent in that Stage 3 commercialization."* Cheniere can't be the only LNG supplier having new commercial discussions. It's why we believe the Mozambique delays + Asian LNG buyers moving to long term deals will effectively force major LNG players to look to see if there are brownfield LNG projects they should look to advance. Prior to March/April, no one would think Shell or other major LNG players would be considering any new LNG FIDs in 2021. Covid forced all the big companies into capital reduction mode and debt reduction mode. But Brent oil is now solidly over $70, and LNG prices are over $13 this summer and the world's economic and oil and gas demand outlook are increasing with vaccinations. And we are starting to see companies move to increasing capex with the higher cash flows. The theme in Q3 reporting is going to be record or near record oil and gas cash flows, reduced debt levels and increasing returns to shareholders. And unless new mutations prevent vaccinations from returning the world to normal, we suspect that major LNG players, like other oil and gas companies, will be looking to increase capex as they approve 2022 budgets. The outlook for the future has changed dramatically in the last 8 months. The question facing major LNG players like Shell is should they look to FID new LNG brownfield projects in the face of an increasing LNG supply gap that is going to hit faster and harder and Asian LNG buyers prepared to do long term deals. We expect these decisions to be looked at before the end of 2021 for 2022 capex budget/releases. One wildcard that could force these decisions sooner is the already stressed out global supply chain. We have to believe that discussion there will be pressure for more Asian LNG buyer long term deals sooner than later.

For Canada, does the increasing LNG supply gap provide the opportunity to at least consider a LNG Canada Phase 2 FID over the next 6 months? Our view on Shell and other LNG players is unchanged since our April 28 blog. Shell is no different than any other major LNG supplier in always knowing the market and that the oil and gas outlook is much stronger than 9 months ago. Even 3 months post our April 28 blog, we haven't heard any significant talks on how major LNG players will be looking at FID for new brownfield LNG projects. We don't have any inside contacts at Shell or LNG Canada, but that is no different than when we looked at the LNG markets in September 2017 and saw the potential for Shell to FID LNG Canada in 2018. We posted a September 20, 2017 blog *"China's Plan To Increase Natural Gas To 10% Of Its Energy Mix Is A Global Game Changer Including For BC LNG*" [LINK]. Last time, it was a demand driven supply gap, this time, it's a supply driven supply gap. We have to believe any major LNG player, including Shell, will be at least looking at their brownfield LNG project list and seeing if they should look to advance FID later in 2021. Shell has LNG Canada Phase 2, which would add 2 additional trains or approx. 1.8 bcf/d. And an advantage to an FID would be that Shell would be able to commit to its existing contractors and fabricators for a continuous construction cycle following on LNG Canada Phase 1 ie. to help keep a lid on capital costs. We believe maintaining a continuous construction cycle is even more important given the stressed global supply chain. No one is talking about the need for these new brownfield LNG projects, but, unless some major change in views happen, we believe its inevitable that these brownfield LNG FID internal discussions will be happening in H2/21. Especially since the oil and gas price outlook is much stronger than it was in the fall and companies will be looking to increase capex in 2022 budgets.

A LNG Canada Phase 2 would be a big plus to Cdn natural gas. LNG Canada Phase 1 is a material natural gas development as its 1.8 bcf/d capacity represents approx. 20 to 25% of Cdn gas export volumes to the US. The EIA data shows US pipeline imports of Cdn natural gas as 6.83 bcf/d in 2020, 7.36 bcf/d in 2019, 7.70 bcf/d in 2018, 8.89 bcf/d in 2017, 7.97 bcf/d in 2016, 7.19 bcf/d in 2015 and 7.22 bcf/d in 2014. A LNG Canada Phase 2 FID would be a huge plus for Cdn natural gas. It would allow another ~1.8 bcf/d of Cdn natural gas to be priced against pricing points other than Henry Hub. And it would provide demand offset versus Trudeau if he moves to make electricity "emissions free" and not his prior "net zero emissions". Mozambique has been a game changer to LNG outlook creating a bigger and sooner LNG supply gap. And with a stronger tone to oil and natural gas prices in 2021, the LNG supply gap will at least provide the opportunity for Shell to consider FID for its brownfield LNG Canada Phase 2 and provide big support to Cdn natural gas for the back half of the 2020s. And perhaps if LNG Canada is exporting 3.6 bcf/d from two phases, it could help flip Cdn natural gas to a premium vs US natural gas especially if Biden is successful in reducing US domestic natural gas consumption for electricity. The next six months will be very interesting to watch for LNG markets and Cdn natural gas valuations. Imagine the future value of Cdn natural gas is there was visibility for 3.6 bcf/d of Western Canada natural gas to be exported to Asia.

https://www.reuters.com/business/energy/exclusive-china-looks-lock-us-lng-energy-crunch-raises-concerns-sources-2021-10-15/?taid=61699e890fbc4500016a9b71&utm_campaign=trueAnthem:+Trending+Content&utm_medium=trueAnthem&utm_source=twitter

October 16, 20214:59 PM MDTLast Updated 13 hours ago

EXCLUSIVE China looks to lock in U.S. liquefied natural gas in energy crunch

By Chen Aizhu and Jessica Jaganathan, Scott Disavino

SINGAPORE/NEW YORK, Oct 15 (Reuters) - Major Chinese energy companies are in advanced talks with U.S. exporters to secure long-term liquefied natural gas (LNG)supplies, as soaring gas prices and domestic power shortages heighten concerns about the country's fuel security, several sources said.

At least five Chinese firms, including state major Sinopec Corp and China National Offshore Oil Company (CNOOC) and local government-backed energy distributors like Zhejiang Energy, are in discussions with U.S. exporters, mainly Cheniere Energy (LNG.A) and Venture Global, the sources told Reuters.

The discussions could lead to deals worth tens of billions of dollars that would mark a surge in China's LNG imports from the United States in coming years. At the height of a Sino-U.S. trade war in 2019, gas trade briefly came to a standstill. LNG export facilities can take years to build, and there are several projects in North America in the works that are not expected to start exporting until the middle of the decade.

Talks with U.S. suppliers began early this year but speeded up in recent months amid one of the biggest power-generating, heating fuel crunch in decades. Natural gas prices in Asia have jumped more than fivefold this year, sparking fears of power shortages in the winter.

"Companies faced a supply gap (for winter) and surging prices. Talks really picked up since August when spot prices touched $15/mmbtu", said a Beijing-based senior industry source briefed on the talks.

Another Beijing-based source said: "After experiencing the recent massive market volatility, some buyers were regretting that they didn't sign enough long-term supplies."

Imports for winter of 2021 are capped as soaring global prices hurt demand

Sources expected fresh deals to be announced over the coming few months, after privately controlled ENN Natural Gas Co, (600803.SS), headed by the ex-LNG chief of China's largest buyer, CNOOC, announced a 13-year deal with Cheniere on Monday. read more

It was the first major U.S.-China LNG deal since 2018.

The new purchases will also cement China's position as the world's top LNG buyer, taking over from Japan this year.

"As state-owned enterprises, companies are all under pressure to keep security of supply and the recent price trend has deeply changed the image of long-term supplies in the mind of leadership," said the first Beijing-based trader.

"People may have taken the spot (market) as the key in the past, but are now realizing that long-term cargoes are the backbone."

CHEAPER U.S. GAS

The sources declined to be identified as the negotiations are private.

Sinopec declined comment. CNOOC and Zhejiang Energy did not immediately respond to requests for comment.

Venture Global and Cheniere both declined comment.

"We expect more deals to be signed before year-end. It's primarily driven by the global energy crunch and prices we're seeing now... U.S. supplies now stand out as attractive," said a third Beijing source briefed on the talks.

U.S. cargoes used to be expensive versus oil-linked supplies from Qatar and Australia for example, but are cheaper now.

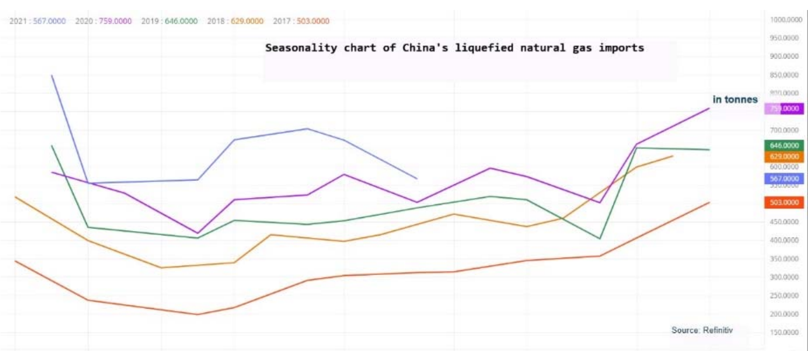
A deal at $2.50 + 115% of Henry Hub futures , similar to ENN's deal according to traders, would be roughly about $9-$10 per million British thermal units (mmBtu) on a delivered basis into Northeast Asia. This includes an average shipping cost of $2 per mmBtu for the U.S.-China route.

Jason Feer, global head of business intelligence with consultancy Poten & Partners said Chinese companies are heavily exposed to Brent-related pricing for LNG and the U.S. purchases give some diversity to the pricing.

Asian spot gas prices are currently trading at above $37 per mmBtu after reaching a record high of over $56 earlier this month. read more

Traders expect prices to go higher in winter when demand typically surges.

Chinese buyers are scouting for both near-term shipments to cover demand this winter and long-term imports as demand for gas, seen by Beijing as a key bridge fuel before reaching its 2060 carbon-neutral goal, is set for steady growth through 2035.



China's H1 2021 imports surged 28% on yr in counter-seasonal spike, but H2 imports seen capped by high prices

It's hard to estimate a total volume of the deals being discussed, sources said, but Sinopec alone could be eyeing 4 million tonnes annually as the company is most exposed to the spot market versus domestic rivals PetroChina and CNOOC, said a third source.

Traders said Sinopec is in final talks with 3 to 4 companies to buy 1 million tonnes a year for 10 years, starting from 2023, and is looking for U.S. volumes as part of the requirement.

Delays in LNG export projects in Canada, in which PetroChina owns a stake, and Mozambique, where both PetroChina and CNOOC have invested, also made U.S. supplies attractive, sources added.

North American LNG exporters have been adding to capacity because of demand in major Asian economies.

Cheniere, the largest exporter out of the United States, said in late September it expects to announce "a number of other transactions" that will support their going forward with the Corpus Stage 3 expansion next year.

Venture Global is building or developing over 50 million tonnes per annum (MTPA) of LNG production capacity in Louisiana, including the 10-MTPA Calcasieu, which is expected to cost around $4.5 billion and start producing LNG in test mode in late 2021. read more

However, some buyers remained cautious.

"There is a lot of hype in the market and nobody knows for sure how long this supply crunch would last. For companies that do not have fresh demand in the next year or two, it's better to wait," said a separate Chinese importer.

Reporting by Chen Aizhu, Jessica Jaganathan in Singapore and Scott Disavino in New York; additional reporting by Gary McWilliams in Houston; editing by Raju Gopalakrishnan, Jason Neely, Peter Graff

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RUSSIAN ENERGY WEEK - 2021
OCT 14, 02:19Updated Oct 14, 03:33

Novak said Nord Stream 2 will be ready to launch in the coming days

The Deputy Prime Minister noted that the pipe is being filled with gas

MOSCOW, October 14. / TASS /. The Nord Stream 2 gas pipeline will be ready for launch in the coming days, the pipeline is already being filled with gas. This was announced by Deputy Prime Minister of the Russian Federation Alexander Novak during a session at the Russian Energy Week.

Nord Stream 2 has been completed. Commissioning and filling of the pipe with the required technological amount of gas are underway. And I believe that it will be ready for operation in the coming days, in order to launch it, "Novak said.

At the same time, he noted that the further situation with the operation of the pipeline depends on the European regulator. Commercial gas supplies via Nord Stream 2 may begin immediately after obtaining permission from the regulator, the Deputy Prime Minister stressed, adding that supplies also depend on applications from European consumers.

On October 4, the Danish Energy Agency announced that Nord Stream 2 AG had fulfilled all the conditions for putting Nord Stream 2 into operation. The company announced the start of filling the first string of the gas pipeline with gas. Commissioning work on the second line continues.

About Forum

The International Forum "Russian Energy Week" is a discussion platform in Russia aimed at discussing the challenges and prospects for the development of the world fuel and energy complex. This year the conference is being held in the Moscow Manege on October 13-15. In total, the forum will include more than 30 business events, in which the heads of more than 200 companies from various sectors of the fuel and energy complex will take part. The Global Energy Prize laureates were also awarded within the framework of the forum. By tradition, the program of the forum will end on October 15, the youth day.

Shell: “Every LNG Cargo That Could Technically Be Produced In This World Has Been Produced And Has Found A Well Paying Customer”

Posted: September 20, 2017

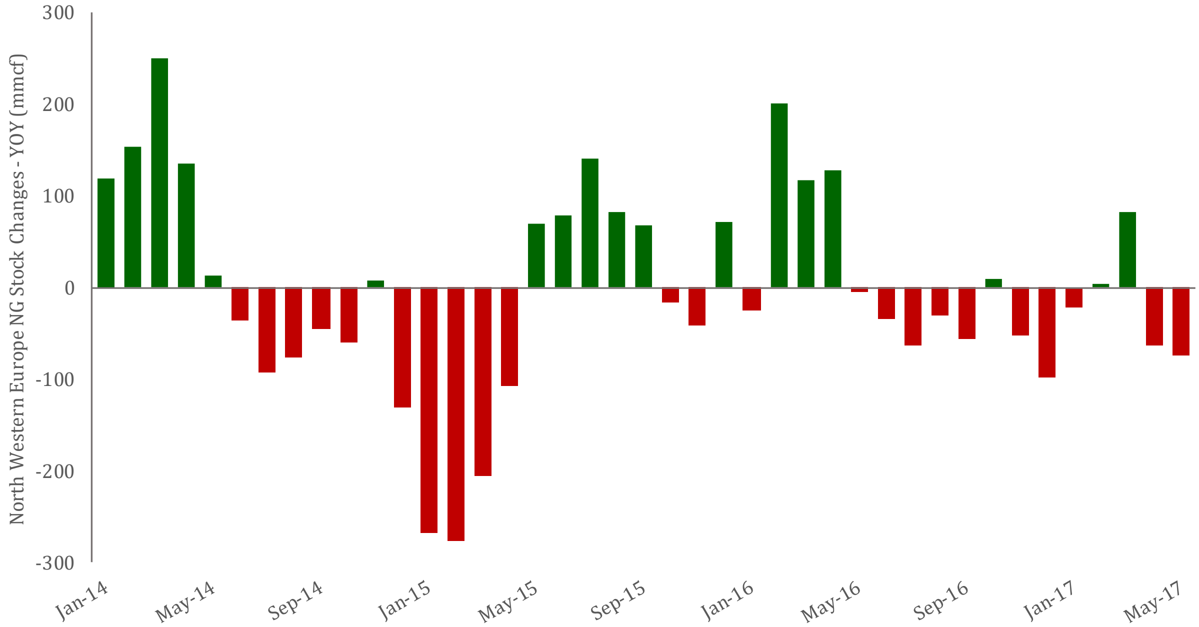
We will be presenting a very bullish outlook for natural gas later today in our webcast for Stream’s 2018 Energy Outlook. The key to our call is that a massive natural gas demand surge has started and will lead to world LNG markets being corrected closer to 2020 than the current conventional wisdom of closer to 2025. One of the reasons we see this happening quickly is we share Shell’s view that global LNG markets, as of mid 2017, are not in an oversupply situation and there is data support (Japan LNG spot prices, NW Europe storage) for this view. Two weeks ago, Shell said “*Actually, over the last 18 months, every LNG cargo that could technically be produced in this world has been produced and has found a well-paying customer”.* Therefore, we have a different starting point than conventional wisdom that says LNG markets are oversupplied in 2017. And if you combine a different starting point with a different view on a massive surge in natural gas demand, then you end up with a much different view of when LNG markets will move to undersupply. We will be posting a blog post today’s webcast on why we see a massive surge in natural gas demand.

A massive surge in natural gas demand has started. Long term readers of Energy Tidbits will likely be surprised by the very bullish natural gas call in this afternoon’s webcast. I was very negative for years, but move to a positive stance a year ago driven by the themes of Floating Storage Gas Regasification Units (FSRUs) and increasing US exports of LNG and to Mexico via pipeline. Those themes are continuing and FSRUs are expanding in their scope. Natural gas has already been on a path of strong demand growth. That path is continuing. But later today, we will be highlighting other major new demand factors that will drive the massive surge in global natural gas demand. This isn’t just an item for investors outside of Canada. Nor is it an item for a couple years down the road. We see these themes impacting Cdn natural gas in 2018. The 2018 Energy Outlook is at 2pm mountain today and can be accessed via[LINK].

Shell’s LNG head Maarten Wetselaar says the LNG market is in balance and all LNG cargos have found well paying customers. Two weeks ago, Shell’s LNG head, Maarten Wetselaar (Integrated Gas & New Energies Director) presented to the Australian financial community at Bloomberg’s Sydney Australia office. The presentation and Q&A in particular was excellent, but the presentation was overlooked because it was only available over the Bloomberg terminal and Shell did not post Wetselaar’s presentation. Bloomberg only posted a small portion of their interview with Wetselaar [LINK]. We prepared a transcript of Wetselaar’s comment on the balanced LNG market. He said “*We have been very pleased to see very strong demand for LNG in the last two years from Asia, particularly from China, but also from new countries that demand LNG in order to make their energy mix go around. There is Pakistan, there is Egypt, and even this year, we see the demand response to the supply increase being very robust so this year we have not seen an oversupply in this product. Actually, over the last 18 months, every LNG cargo that could technically be produced in this world has been produced and has found a well-paying customer. So, this market is in more balance than people perhaps perceive*”.

The key data support to Wetselaar is that NW Europe storage is not seeing surplus LNG cargos looking for a home. In the Q&A, Wetselaar said the data support for his comment that the market is absorbing all of the new LNG supply is to look at NW Europe storage. Wetselaar did not use the description dumping ground, but it is the right term. Webster’s defines “dumping ground” as “*a place to which unwanted people or things are sent*”. He noted that if LNG was in oversupply, there would be surplus LNG cargos looking for a home and these surplus LNG cargos would find their way to NW Europe storage. Shell is not seeing any YoY increase in NW Europe storage. Hence, he is firm in his view that demand was absorbing all the new LNG supply in 2017. We pasted the NW Europe storage data into the below graph and it shows exactly what Wetselaar said – the monthly YoY changes in storage do not show increases in the net storage withdraw/injections, which implies that there isn’t any dumping of surplus LNG cargos in NW Europe storage. We have not been following NW Europe natural gas storage, but now have it on our regular data check list because of Wetselaar’s comments.

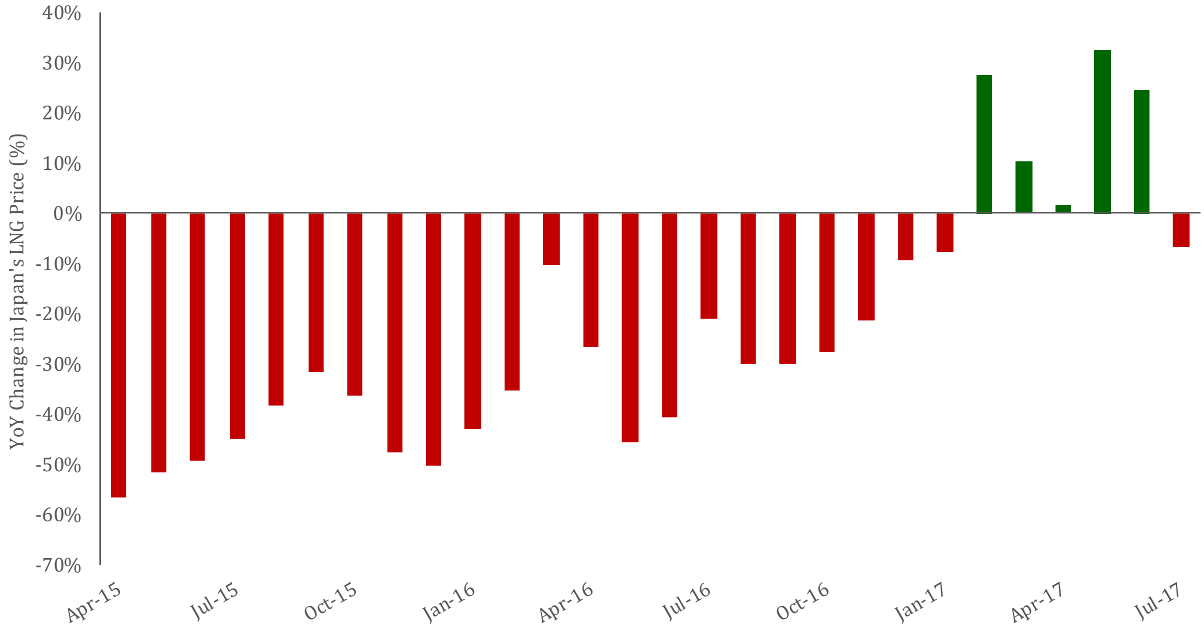
NW Europe YoY Changes In Monthly Storage Net Injections/Withdraw



Source: Bloomberg, Stream Asset Financial

We also believe Japan LNG spot price indicates that the market is absorbing all new LNG supply. We don't disagree that LNG was oversupplied in 2015 and 2016, but, in addition to the NW Europe storage data, we see other data suggesting that all of this new LNG supply is being absorbed by the market. We regularly track Japan LNG spot monthly prices as published by Japan's Ministry of Economy, Trade and Industry and include our graph below showing the YoY change in Japan monthly LNG spot prices. Japan LNG spot prices went down YoY in 2015 and 2016, which was a clear sign there that LNG supply was exceeding demand. But in H1/2017, the Japan LNG spot prices are higher YoY by about 20%. We look at this data and say it is reflective of a LNG market that is balance or at least where the market is absorbing LNG cargos. If LNG markets were still oversupplied like they were in 2015 and 2016, we wouldn't see Japan spot LNG prices up 20% this year?

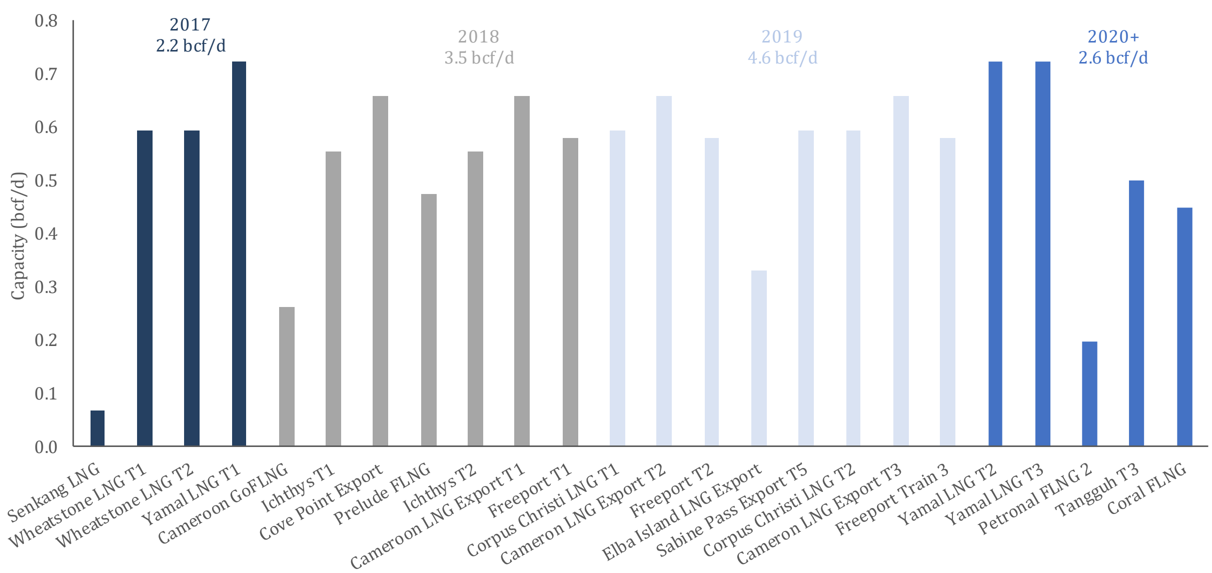
Japan Spot LNG Prices – YoY Monthly Change



Source: Japan Ministry of Economy, Trade and Industry, Stream Asset Financial

<u>The big test is coming in 2018/2019 with 8.1 bcf/d of new LNG supply to come on stream.</u> In our webcast, we will be reviewing factors that should lead to additional LNG demand of 3.5 to 4.5 bcf/d per year more than expected. This additional LNG demand may not all kick in right away but certainly in 2019 and 2020. Please note this is additional demand every year, not just a one-shot boost. Even still, this massive test of increasing demand will be tested in 2018 and 2019 with under construction LNG supply projects expected to add 3.5 bcf/d in 2018 and 4.6 bcf/d in 2019. Then new LNG supply goes down to 2.6 bcf/d in 2020. Inevitably there will be delays to the startup for some of these projects. But if not, it will be a big test. It may well be that the timing for the increased surge in natural gas demand may not line up exactly with the timing of the new LNG supply but it means that any oversupply should be temporary and quickly fixed. Below is our running table of the LNG liquefaction projects that are under construction.

Under Construction LNG Liquefaction Projects



Source: Company Reports, Stream Asset Financial

<u>A better starting point moves LNG to undersupply quicker, especially if combined with a massive surge in natural gas demand.</u> We are highlighting the starting point for LNG markets as it makes a big difference to looking ahead to when LNG moves to undersupply. Conventional wisdom is that LNG is oversupplied in 2017, but we are in the Shell camp that LNG is not oversupplied today because the market is absorbing the increasing LNG supply. We don't see the Japan LNG spot prices and NW Europe storage data suggesting a robust market, but supportive of Shell's view. If you combine a different starting point (LNG is not in oversupply right now) with a different view on a massive surge in natural gas demand, then you end up with a much different view of when LNG markets will move to undersupply. Later today, we will be presenting the reasons for why we see a massive surge in natural gas demand that should lead to increased LNG demand of 3.5 to 4.5 bcf/d per year. US HH gas prices continue to be increasingly linked to global gas prices and this will increase with the under construction 4.6 bcf/d of US LNG capacity to be added thru 2020. We see this as a game changer to natural gas prices in the mid term (2019 to 2024), and why HH gas prices could be ~40% above the post 2019 long dated strips. Cdn gas prices should be dragged up with HH but the tone and valuations to Cdn natural gas should reflect this massive global natural gas demand surge in 2018 and 2019.

China's Plan To Increase Natural Gas To 10% Of Its Energy Mix Is A Global Game Changer Including For BC LNG

Posted: Sept 20, 2017

The news flow from China this summer on its increasing fight and urgency to fight pollution supports China's plan to increase natural gas to 10% of its energy mix in 2020 and 15% of its energy mix in 2030. This is a game changer to global natural gas markets and, by itself, can bring LNG to undersupply 2 to 3 years earlier than expected. China's natural gas consumption increased by ~15% per year from 2005 thru 2016 and ~1.5 bcf/d per year vs China's 8.5% growth rate in energy in total. Yet natural gas only got to 5.9% of China's energy mix. If China is to hit 10% by 2020, it will need to increase natural gas consumption by 4 to 5 bcf/d per year. Assuming China continues to grow its domestic natural gas production by 0.6 bcf/d per year (its growth rate for last five years), China will need to import an additional ~3.5 to ~4.5 bcf/d per year. This is "per year"! And if so, we believe BC LNG will be back and there is a higher probability than ever before for a Shell FID on its BC LNG project in 2018.

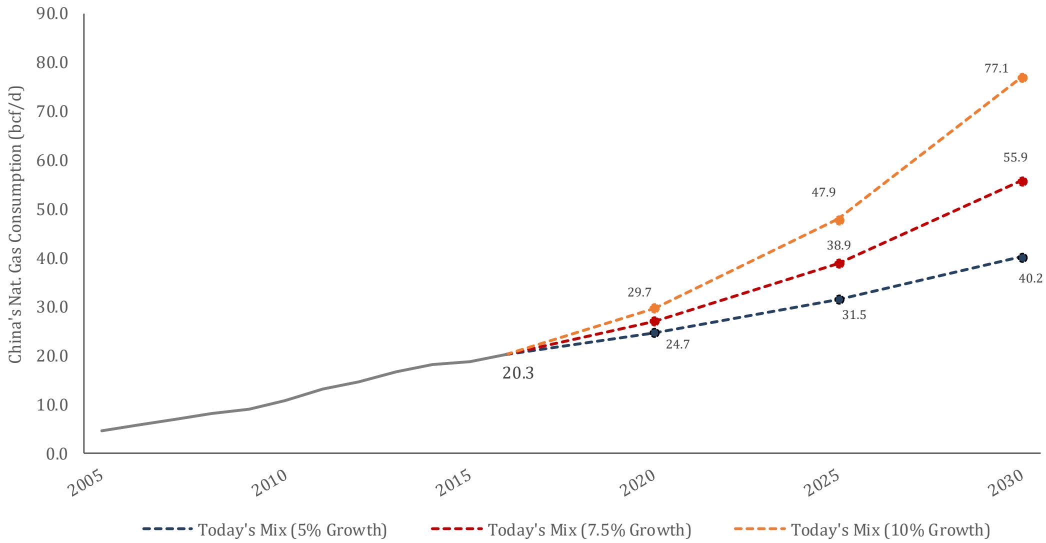
<u>China has had strong growth in natural gas demand to date.</u> China's natural gas consumption has increased by 15% per year from 2005 thru 2016. This was from a small base as China's natural gas consumption was only 4.7 bcf/d in 2005. But it reached 20.3 bcf/d in 2016, or approx. 1.5 bcf/d increase per year. To put in perspective, US natural gas consumption was ~75 bcf/d in 2016 and Canada was ~11 bcf/d in 2016. Natural gas consumption increase of ~15% was almost twice China's growth rate in energy consumption of ~8.5%. But even still, at 20.3 bcf/d in 2016, natural gas was still only 5.9% of China's total energy mix.

<u>There seems to be a greater urgency to switch from coal to natural gas before the winter to fight pollution.</u> This is what got our attention over the summer and caused us to focus on China's plan to increase natural gas in its energy mix. There has been an increasing flow of news this summer on actions to fight pollution. Anyone who has been to Beijing can tell you that the pollution issue is only getting worse. But what caught our attention was the Sat Sept 16 news reports in the South China Morning Post [LINK] and Xinhua news [LINK] on new actions to immediately switch from coal to natural gas for this winter. Hebei province is switching 1.8 million households to natural gas by Oct 31! SCMP reported that the Hebei province "*announced on its website on Friday that 1.8 million households would switch to natural gas from coal for fuel and heating in order to improve air quality*" and "*Meanwhile, the Hebei authorities said 1.8 million households in the province would make the switch to natural gas by the end of October so that it can meet air quality targets*". Xinhua reported that "*China has regulated use of cleaner fuel for heating in north China, where coal burning in winter is a major source of pollution. In the Beijing-Tianjin-Hebei region and nearby areas, 28 cities will now use only natural gas, electricity and renewable energy for heating".*

<u>China's domestic natural gas production has grown by 0.6 bcf/d per year for last 5 years.</u> BP Amoco estimates for China's domestic natural gas production was 5.9 bcf/d in 2006, reached 10.5 bcf/d in 2011 and finally 13.4 bcf/d in 2016. This is annual growth rate of 0.6 bcf/d for the last five years and 0.75 bcf/d for the last 10 years. The largest annual increases were 1.1 bcf/d in each of 2008 and again in 2010, whereas the smallest annual increase was 0.2 bcf/d in 2016.

<u>China's natural gas imports should increase by ~1.9 bcf/d per year assuming no change to a 5.9% share of the energy mix,</u> As a reminder, China's natural gas consumption has grown by ~15% per year and its total energy consumption by ~8.5% per year. We projected China's natural gas consumption starting from the current 20.3 bcf/d and 5.9% share of energy mix, and grew it by 5%, 7.5% or 10%. The mid case being generally in line with China's historical energy growth. In other words, we aren't assuming any major increase in the 5.9% share of total energy. Under the 7.5% growth case, China's natural gas consumption would increase by ~2.5 bcf/d per year, and natural gas imports by ~1.9 bcf/d per year assuming China's production growth is 0.6 bcf/d per year. It's a strong growth case for China and slightly higher than its historical 1.5 bcf/d per year growth in natural gas consumption. But remember, it doesn't increase natural gas from its current 5.9% share of the energy mix. .

China's Natural Gas Consumption Based On Current 5.9% Share Of Energy Mix

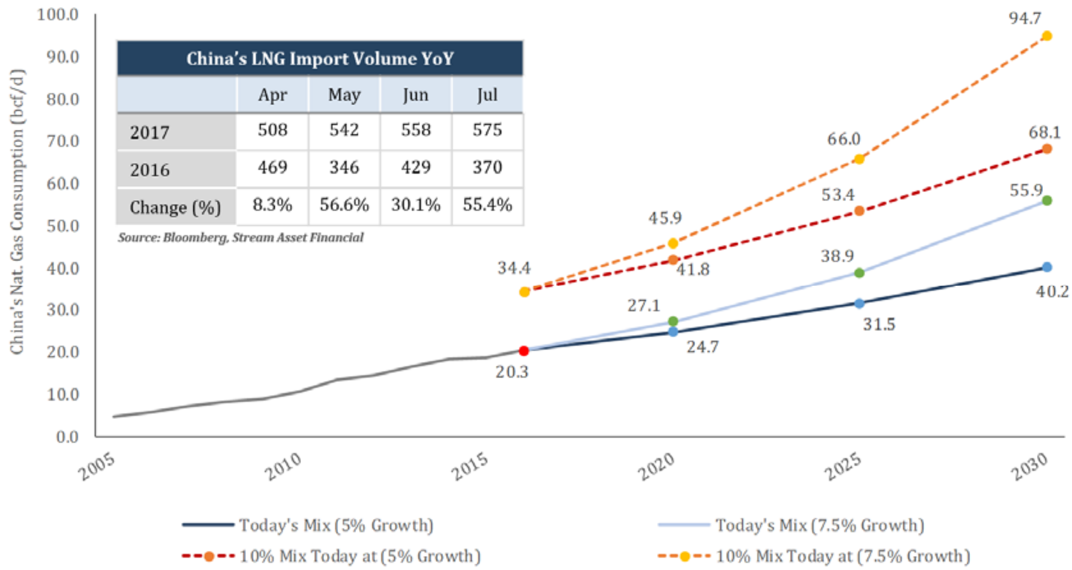


Source: BP Amoco, Stream Asset Financial

<u>However, a shift to a 10% share of energy would increase China's natural gas imports by ~3.5 bcf/d to ~4.5 bcf/d per year.</u> As good as China's natural gas demand growth has been, Its only going to get bigger as China moves to its target that natural gas would be 10% of its energy share in 2020 and 15% in 2030. This may not seem like much, but the math says to hit a 10% target, let alone a 15% share target, China will need to increase natural gas demand by 4 to 5 bcf/d per year and its imports by ~3.5 to ~4.5 bcf/d per year.

We took the above graph and added a line to show where China's natural gas consumption wouild be if it was already at 10% of the energy mix. If so, it would be at 34.4 bcf/d instead of its current 20.3 bcf/d. We used that point to project where natural gas consumption will be at a 10% share of energy mix and assuming energy growth is increased by 5% or 7.5% per year. Remember that energy use has increased by 8.5% per year, and that we did not put in a 15% of total energy case which is China's target for 2030. It means that to get to 10% of the energy mix in 2020 and a 7.5% total energy growth, natural demand would need to go from 20.3 bcf/d to 45.9 bcf/d in 2020 (+6.4 bcf/d per year) and 66.0 bcf/d in 2025 (+5.1 bcf/d per year). Under a 5% energy growth rate case, natural gas demand would need to go from 20.3 bcf/d to 41.8 bcf/d in 2020 (+5.4 bcf/d per year) and to 53.4 bcf/d in 2025 (+3.7 bcf/d per year). If we are conservative and use 4 to 5 bcf/d per year increase in natural gas consumption, this would mean an increase in natural gas imports of ~3.5 to ~4.5 bcf/d per year. This is a WOW! and even before we even think about natural gas moving to 15% of the energy mix in 2030.

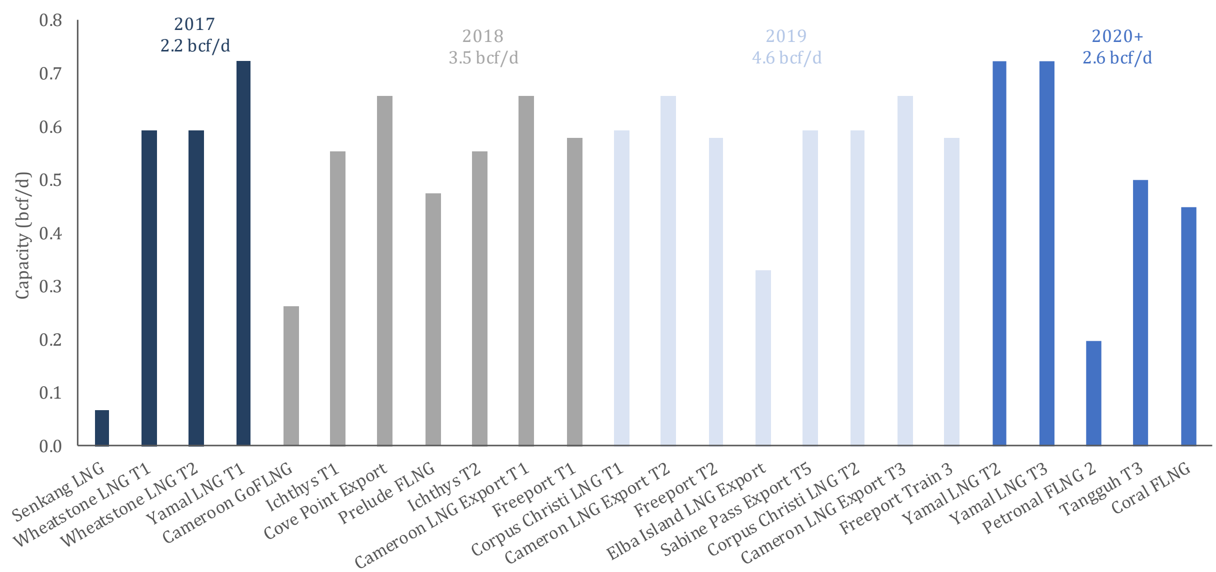
China's Natural Gas Consumption Based On Moving To 10% Share Of Energy Mix



Source: BP Amoco, Stream Asset Financial

<u>This is why we see the market being able to absorb quickly the 8.1 bcf/d of new LNG supply in 2018/2019.</u> As noted in our earlier blog today, the big test is coming up with under construction LNG supply projects expected to add 3.5 bcf/d in 2018 and 4.6 bcf/d in 2019. Then new LNG supply goes down to 2.6 bcf/d in 2020. If China is to get natural gas consumption to 10% of its energy mix by 2020, it is going to have to increase natural gas imports by ~3.5 bcf/d to ~4.5 bcf/d. It is why we see any oversupply caused by timing of supply additions vs demand growth should be temporary and be fixed quickly.

Under Construction LNG Liquefaction Projects



Source: Company Reports, Stream Asset Financial

<u>If China can move to natural gas to 10% of its energy mix, it can move LNG markets to undersupply closer to 2020 than the conventional wisdom of closer to 2025.</u> We recognize this is a major difference in the conventional wisdom views. Its not that we are trying to be bold, but the urgency we are seeing in China this summer to fight pollution

makes us think that their plan to increase natural gas to 10% of its energy mix is a logical plan that they are working to attain. The math suggests that the conventional wisdom of LNG being oversupplied until close to 2025 is off by a few years and it will be fixed closer to 2020. Under construction US LNG projects are expected to add 4.6 bcf/d of new capacity thru 2020 and this provides increasing linkage of HH prices to global markets.   It also is why we see HH gas prices potentially being ~40% above long dated strips post 2019. Cdn gas prices will be dragged up with HH prices, but we expect the 2018 and 2019 valuations and tone to Cdn natural gas to reflect this natural gas demand surge.

And it means that BC LNG will be back. We recognize that CNOOC just stopped pursing its BC LNG Aurora project and that the new BC NDP government isn't viewed as being LNG friendly. And it will surprise long term readers of Energy Tidbits who know we have never believed BC LNG would happen.   We always believed it had no hope, or at least we did up until the last two months. But that was before we saw the urgency and seriousness of China's move to increase natural gas at the cost of coal and that China's LNG imports were up 38% YoY in H1/17.   The math that shows China will need to increase its natural gas imports by ~3.5 bcf/d to ~4.5 bcf/d per year means that BC LNG has to be back on the map. Shell has always been the higher probability of being the first BC LNG player. BC LNG will have to be cost competitive, but it also gives Shell more diversity to its LNG supply - a good thing for a global supplier of LNG. Especially with the increasing risk of North Korea and separately China's increasing territorial claim to the South China Sea shipping lanes from its island building. So, it may be a wildcard, but why we said earlier Cdn investors need to pay attention to what China is doing to increase natural gas share of its energy mix. For Canada, this should impact natural gas valuations in 2018 and 2091. And perhaps most of all for Canada, its why we see a better chance than ever to see a Shell FID on its BC LNG in 2018.

Director's Cut
August 2021 Production

Oil Production

July	33,374,420 barrels = 1,076,594 barrels/day (final)
August	34,323,696 barrels = 1,107,216 barrels/day +2.8% RF+1% NM 1.220.000
	1,066,115 barrels/day or 96% from Bakken and Three Forks
	41,101 barrels/day or 4% from legacy pools
	(all-time high 1,519,037 BOPD Nov 2019)

Revised Revenue Forecast **= 1,200,000→<u>1,100,000</u>→1,000,000 barrels/day**

Crude Price[1] ($/barrel)

	North Dakota Light Sweet	WTI	ND Market estimate	
July	64.80	72.43	66.93	
August	60.94	67.71	62.50	
Today	73.75	80.52	77.14	RF+54%
All-time high (6/2008)	$125.62	$134.02	$126.75	

Revised Revenue Forecast **= $50.00**

Gas Production & Capture

July Production	89,261,659 MCF = 2,879,408 MCF/day
Gas Captured: 90%	79,965,641 MCF = 2,579,537 MCF/day
August Production	91,774,175 MCF = 2,960,457 MCF/day (all-time high 3,145,172 MCFD Nov 2019) +2.8%
Gas Captured: 92%	84,173,466 MCF = 2,715,273 MCF/day (all-time high 2,899,998 MCFD Mar 2020)

Rig Count

July	23
August	28
September	27
Today	*30 NM86*
Federal Surface	0
All-time high	*218 (5/29/2012)*

[1] Pricing References: WTI: EIA and CME Group; ND Light Sweet: Flint Hills Resources

Wells

	July	August	September	Revised Revenue Forecast
Permitted	40 drilling 0 seismic	79 drilling 0 seismic	69 drilling 2 seismic (All-time high was 370 – Oct. 2012)	-
Completed	53 (Final)	47 (Revised)	34 (Preliminary)	**30→<u>40</u>→50→60**
Inactive[2]	2,082	1,672	-	-
Waiting on Completion[3]	521	521	-	-
Producing	16,890	16,953 (Preliminary) (All-time high 16,844 in June 2021) *14,713 (87%) from unconventional Bakken – Three Forks* *2,240 (13%) from legacy conventional pools*	-	-

Fort Berthold Reservation Activity

	Total	Fee Land	Trust Land
Oil Production (barrels/day)	253,291	99,695	153,596
Drilling Rigs	3	1	2
Active Wells	2,598	646	1,952
Waiting on completion	TBD		
Approved Drilling Permits	TBD	TBD	TBD
Potential Future Wells	3,954	1,118	2,836

Drilling and Completions Activity & Crude Oil Markets

The drilling rig count was stable in the mid 50's second half of 2019 through May 2020. Drilling rig count fell 51% from January 2020 to August 2021 and is slowly increasing.

The number of well completions has been low and volatile since April 2020 as the number of active completion crews dropped from 25 to 1 then increased to 6 in July 2021 and to 10 this week.

OPEC+ reached a deal Sunday to phase out 5.8 million barrels per day of oil production cuts by September 2022 as prices of the commodity hit their highest levels in more than two years. Coordinated increases in oil supply from the group known as OPEC+ began in August. At their October 4, 2021 meeting OPEC+ decided to stick with their plan to increase production 400,000 barrels per day on a monthly basis going forward.

The International Energy Agency estimates a 1.5 million barrel per day shortfall for the second half of this year, indicating a tight market despite the gradual OPEC supply boost. EIA now estimates that supply and demand are balanced with demand returning to 2019 levels in the second quarter 2022.

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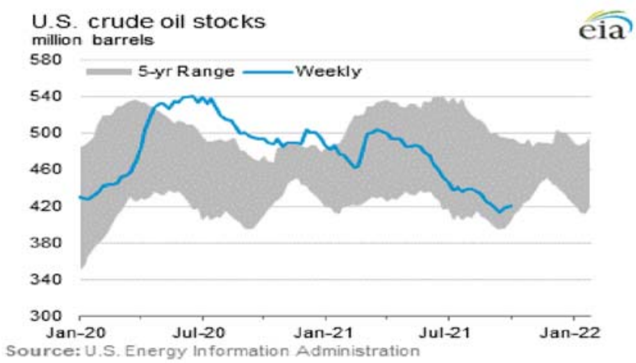
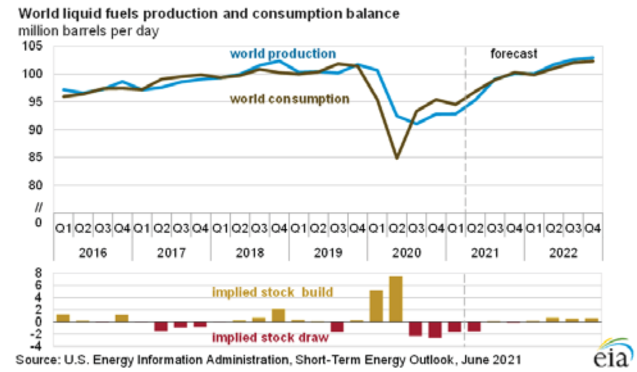
[2] Includes all well types on IA and AB statuses: **IA** = Inactive shut in >3 months and <12 months;
AB = Abandoned (Shut in >12 months)

[3] The number of wells waiting on completions is an estimate on the part of the director based on idle well count and a typical five-year average. Neither the State of North Dakota, nor any agency officer, or employee of the State of North Dakota warrants the accuracy or reliability of this product and shall not be held responsible for any losses caused by this product. Portions of the information may be incorrect or out of date. Any person or entity that relies on any information obtained from this product does so at his or her own risk.





Crude oil transportation capacity including rail deliveries to coastal refineries is adequate, but could be disrupted due to:
US Appeals Court for the ninth circuit upholding of a lower court ruling protecting the Swinomish Indian Tribal Community's right to sue to enforce an agreement that restricts the number of trains that can cross its reservation in northwest Washington state.
DAPL Civil Action No. 16-1534 continues, but the courts have now ruled that DAPL can continue normal operations through March 2022.

Drilling activity is slowly increasing and operators continue to maintain a permit inventory of approximately 12 months.

Gas Capture

US natural gas storage is now 5% below the five-year average. Crude oil inventories are below normal in the US, but world storage is above the five-year average.

The price of natural gas delivered to Northern Border at Watford City increased to $23.42/MCF February 17, 2021 but has returned to a significantly higher than normal level of $5.36/MCF today. This results in a current oil to gas price ratio of 14 to 1. The state wide gas flared volume from July to August decreased 54,686 MCFD to 245,185 MCF per day, and the percent flared decreased to 8.3% while Bakken capture percentage increased to 92%.

The historical high flared percent was 36% in 09/2011.

Gas capture details are as follows:

Statewide	92%
Statewide Bakken	92%
Non-FBIR Bakken	92%
FBIR Bakken	92%
Trust FBIR Bakken	93%
Fee FBIR	79%

The Commission established the following gas capture goals:

74%	October 1, 2014 - December 31, 2014
77%	January 1, 2015 - March 31, 2016
80%	April 1, 2016 - October 31, 2016
85%	November 1, 2016 - October 31, 2018
88%	November 1, 2018 - October 31, 2020
91%	November 1, 2020

Seismic

Seismic activity for oil and gas has stopped.

Active Surveys	Recording	NDIC Reclamation Projects	Remediating	Suspended	Permitted (Oil and Gas)	Permitted (CCS)
0	0	0	0	4	0	2

Agency Updates

BIA has published a new final rule to update the process for obtaining rights of way on Indian land. The rule was published 11/19/15 and became effective 12/21/15. The final rule can be found at https://www.federalregister.gov/articles/2015/11/19/2015-28548/rights-of-way-on-indian-land. On 3/11/16, the Western Energy Alliance filed a complaint and motion for a temporary restraining order and/or a preliminary injunction. On 04/19/16, the US District court for the District of North Dakota issued an order denying the motion for a preliminary injunction. The new valuation requirements were resulting in increased delays so BIA provided a waiver that expires 04/05/2020. On 03/09/2020 the NDIC submitted comments supporting an extension of that waiver through 04/05/2021 to allow infrastructure development to continue while BIA develops and implements the new process. NDIC comments can be found at http://www.nd.gov/ndic/ic-press/Sweeney%20letter%20200309.pdf

BLM on 1/20/21 DOI issued order 3395 implementing a 60 day suspension of Federal Register publications; issuing, revising, or amending Resource Management Plans; granting rights of way and easements; approving or amending plans of operation; appointing, hiring or promoting personnel; leasing; and permits to drill. On 1/27/21 President Biden issued an executive order that mandates a “pause” on new oil and gas leasing on federal lands, onshore and offshore, “to the extent consistent with applicable law,” while a comprehensive review of oil and gas permitting and leasing is conducted by the Interior Department. There is no time limit on the review, which means the president’s moratorium on new leasing is indefinite. The order does not restrict energy activities on lands the government holds in trust for Native American tribes.
What is the percentage of federal lands in ND?
Mineral ownership in ND is 85% private, 9% federal (4% Indian lands and 5% federal public lands), and 6% state. 66% of ND spacing units contain no federal public or Indian minerals, 24% contain federal public minerals, 9% contain Indian minerals,1% contain both.
How many potential wells could be delayed or not drilled by a Biden administration ban on drilling permits and hydraulic fracturing on federal lands?
A spatial query found 3,443 undrilled wells in spacing units that would penetrate federal minerals, 2,902 undrilled wells in spacing units would penetrate BIA Trust minerals (700 tribal minerals and 2,202 allotted minerals), and the total number of wells potentially impacted is 6,345. The minimum number of future Bakken wells is 24,000 so the 3,443 wells on federal public lands = 14%, and the 2,902 wells on trust lands = 12%.
What is the potential federal royalty loss from a Biden administration ban on drilling permits and hydraulic fracturing on federal lands?
A recent study from University of Wyoming estimated the ND loss as follows: 2021-2025 $76 million, 2026-2030 $113 million, 2031-2035 $160 million, and 2036-2040 $221 million for a total of $570 million over 15 years. Please note that 50% of the royalties on federal public lands go to the state and 50% of the state share goes to the county where the oil was produced.

The U.S. Interior Department launched its review of the federal oil and gas leasing program on 3/25/21, a key step that will determine whether the Biden administration will permanently halt new leases on federal land and water. The review kicked off with a public forum on oil and gas leasing on federal land and water, with participants representing industry, environmental conservation and justice groups, labor and others, and commence an online comment period. This input will inform an interim report to be released in early summer outlining next steps and recommendations on the future of the program and what can be done to reform how leases are managed and how much revenue should go to taxpayers and other issues.

On 7/7/21 North Dakota sued the Department of Interior (DOI), Secretary of Interior Debra Haaland, Bureau of Land Management (BLM), Director of the BLM Nada Culver, and Director of the Montana-Dakotas BLM John Mehlhoff in US District Court for the District of North Dakota. The lawsuit requests the court:
Compel the Federal Defendants to hold quarterly lease sales.

MONTHLY UPDATE

AUGUST 2021 PRODUCTION & TRANSPORTATION

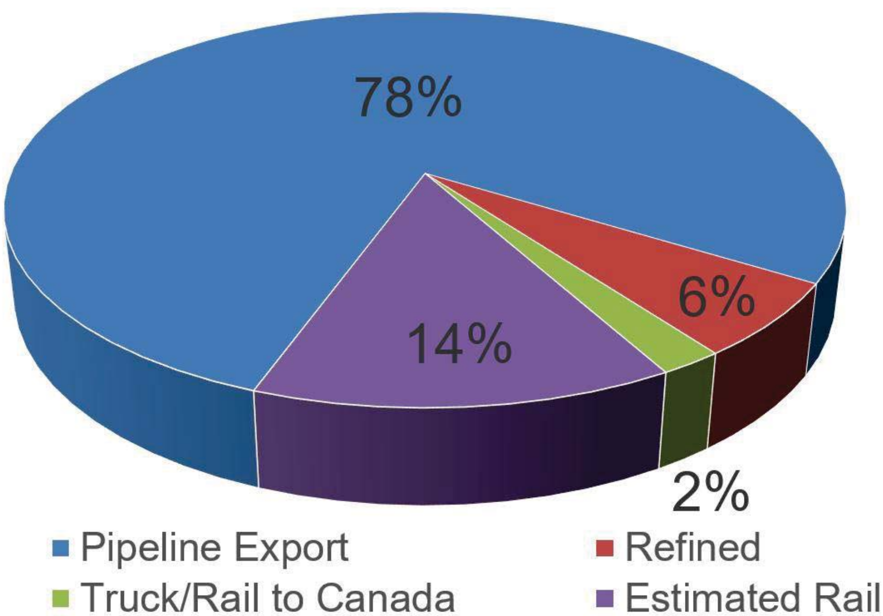
North Dakota Oil Production

Month	Monthly Total, BBL	Average, BOPD
July 2021 - Final	33,374,420	1,076,594
Aug. 2021 - Prelim.	34,323,696	1,107,216

North Dakota Natural Gas Production

Month	Monthly Total, MCF	Average, MCFD
July 2021 - Final	89,261,659	2,879,408
Aug. 2021 - Prelim.	91,774,175	2,960,457

Estimated Williston Basin Oil Transportation, Aug. 2021



CURRENT DRILLING ACTIVITY:

NORTH DAKOTA[1]

30 Rigs

EASTERN MONTANA[2]

1 Rigs

SOUTH DAKOTA[2]

0 Rigs

SOURCE (OCT. 12, 2021):

1. ND Oil & Gas Division
2. Baker Hughes

PRICES:

Crude (WTI): $80.58

Crude (Brent): $83.36

NYMEX Gas: $5.42

SOURCE: BLOOMBERG (OCT 12, 2021)

GAS STATS*

92% CAPTURED & SOLD

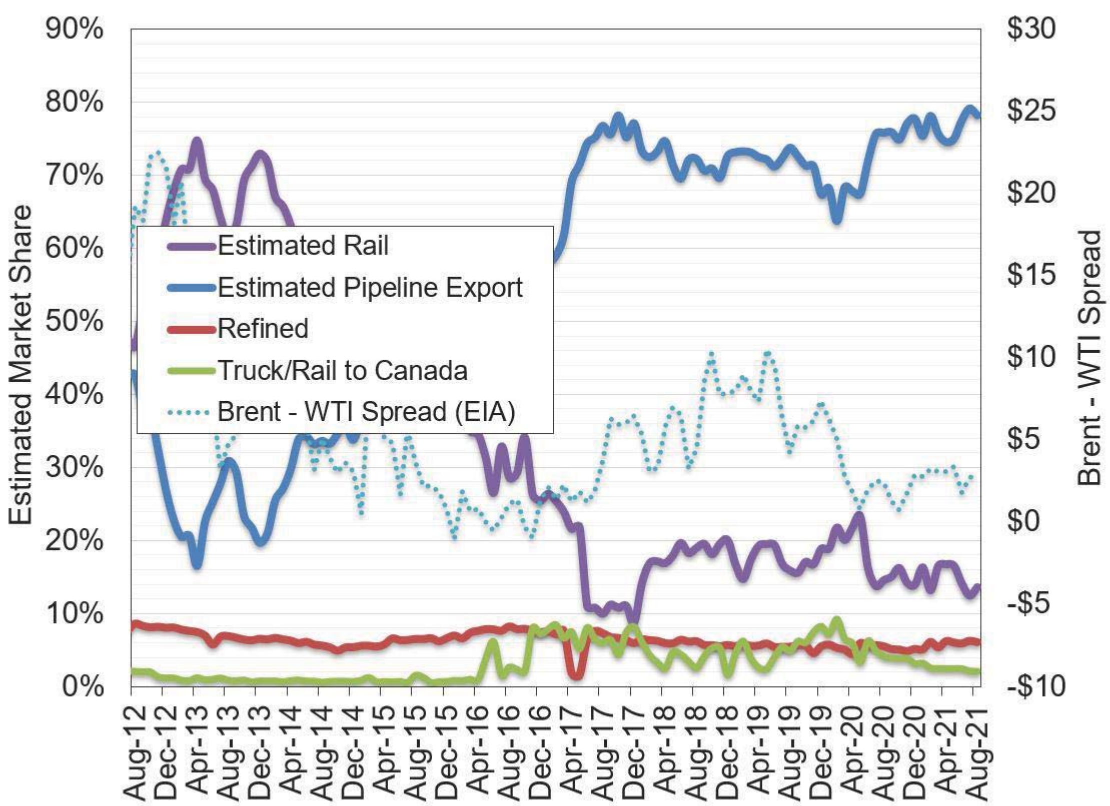
6% FLARED DUE TO CHALLENGES OR CONSTRAINTS ON EXISTING GATHERING SYSTEMS

2% FLARED FROM WELL WITH ZERO SALES

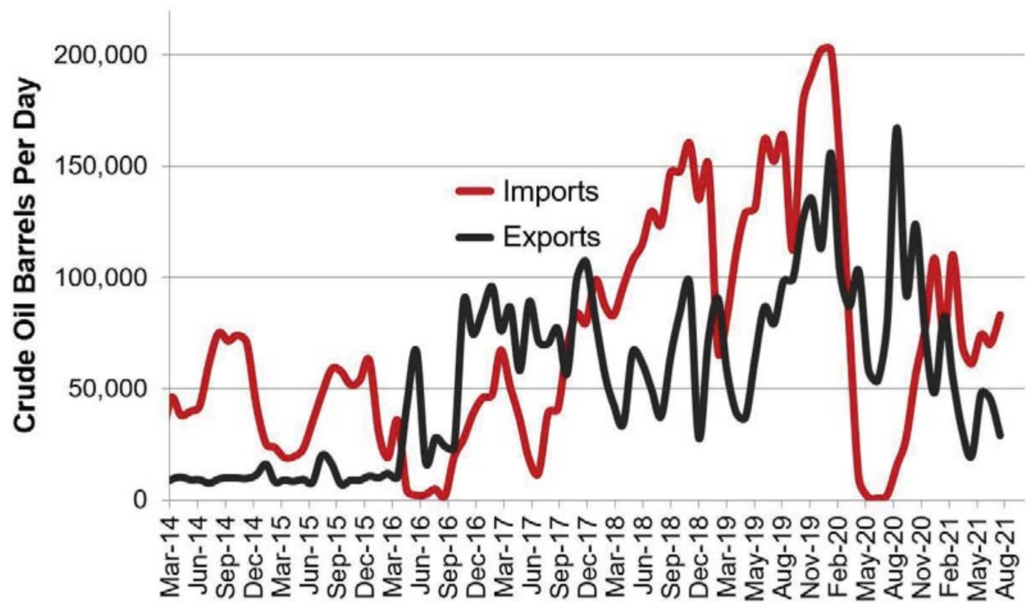
***AUG. 2021 NON-CONF DATA**

Estimated North Dakota Rail Export Volumes

Estimated Williston Basin Oil Transportation

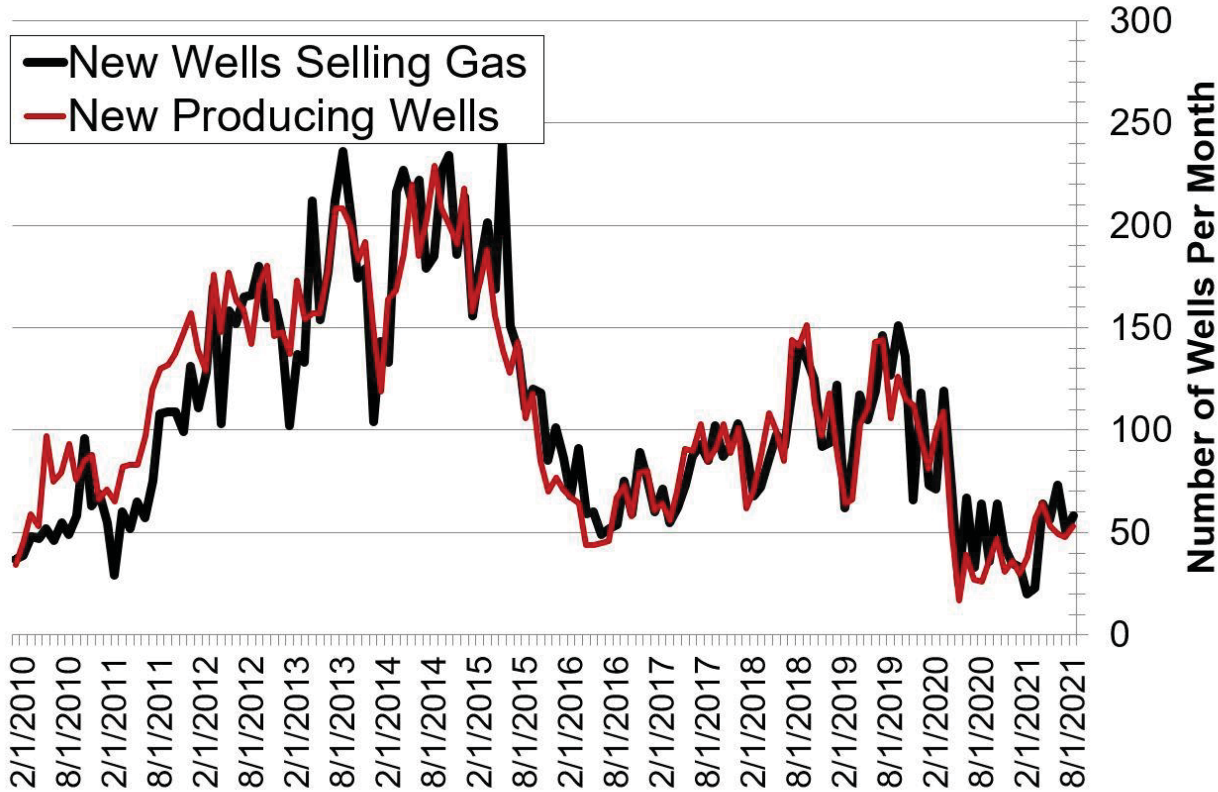


Williston Basin Truck/Rail Imports and Exports with Canada



Data for imports/exports chart is provided by the US International Trade Commission and represents traffic across US/Canada border in the Williston Basin area.

New Gas Sales Wells per Month



US Williston Basin Oil Production, BOPD

2020

MONTH	ND	EASTERN MT*	SD	TOTAL
January	1,431,679	57,460	3,091	1,492,230
February	1,507,069	55,425	3,070	1,565,563
March	1,435,200	57,718	2,946	1,495,864
April	1,225,476	49,054	2,610	1,277,140
May	862,254	37,066	2,466	901,786
June	895,208	42,853	2,680	940,742
July	1,043,089	48,415	3,435	1,094,939
August	1,166,242	46,925	2,807	1,215,973
September	1,224,008	47,128	2,837	1,273,973
October	1,244,056	46,505	2,749	1,293,310
November	1,226,409	45,121	2,798	1,274,327
December	1,191,429	44,500	2,827	1,238,756

2021

MONTH	ND	EASTERN MT*	SD	TOTAL
January	1,147,464	50,140	2,874	1,200,477
February	1,083,716	47,971	2,828	1,134,516
March	1,108,918	49,279	2,744	1,160,941
April	1,123,166	48,203	2,644	1,174,013
May	1,128,042	46,620	2,640	1,177,302
June	1,133,498	43,429	3,103	1,180,030
July	1,076,594	40,631	2,884	1,120,109
August	1,107,216			
September				
October				
November				
December				

* Eastern Montana production composed of the following Counties: Carter, Daniels, Dawson, Fallon, McCone, Powder River, Prairie, Richland, Roosevelt, Sheridan, Valley, Wibaux

Excerpt White House Press Secretary Jen Psaki holds a press briefing, sked FINAL
2021-10-14 21:25:15.78 GMT

QUESITON: Jen, the president has been trying to go back to increase supply in the past. Oil prices have been north of $80 a barrel. Are there any steps that he's looking at, new steps to try to deal with some of these energy issues?

PSAKI: Well, first, the president is very focused on this. He has asked his team about it. There are a number of people, senior members of the White House team from the NSC, from the NEC working on this issue every single day. I would say that part is a supply issue, which is why you asked me about OPEC. That's something we continue to press them on.

But part is also a logistics issue of being able to move supply around the country and that's something that we're also looking into options on. I know you didn't ask me about this but I'm just going to also convey because sometimes they're combined of the gas issue as well as the natural gas issue, which is something that we've seen.

You know people in the Northeast have understandable concerns about what that may look like for them. And I would just note and we haven't talked about this a lot so I wanted to raise it that LIHEAP funding -- coverage o LIHEAP funding is in the American Rescue Plan and that is something that we have been communicating with a number of states and leaders about and their ability to access that funding, which is the low income heating program, I think many of you are familiar with, to help prepare for any increasing costs.

But we're working on both the supply issue and the logistics issue and looking at a range of options. Go ahead.

NATIONAL TANK TRUCK CARRIERS

PETROLEUM DRIVER SHORTAGE AT A GLANCE

The driver shortage has hit the specialized segment of petroleum drivers especially hard. And the COVID-19 pandemic has only exacerbated the issue. The numbers directly below are the results of an NTTC questionnaire of the major players in the country's petroleum-hauling sector, representing roughly 25% of the petroleum hauled in the U.S. Changes are from May 2019 to May 2021.

41.6%
Reduction in qualified driver applicants

23.3%
Reduction in drivers

11%
Reduction in loads hauled (productivity)

HIRES PER JOB POSTINGS

A PROBLEM UNIQUE TO TRUCKING

From September 2016 to January 2021, petroleum carriers and other heavy tractor trailer drivers have seen an average of 1 hire for every 9 job postings. During the same period, the blue collar workforce - a broad pool that covers workers with a high school diploma or less - has seen 1 hire for every 1 job posting. This further highlights the difficulty petroleum carriers have finding qualified professional drivers to fill increasing demand.

2:1 WAREHOUSE WORKERS

1:9 HEAVY TRACTOR TRAILER DRIVERS

1:1 BLUE COLLAR WORKERS

1:2 LIGHT TRUCK DRIVERS

AN AGING WORKFORCE

80% over 45

Truck drivers are much older than the workforce at large. Without an influx of young drivers, the shortage will only grow more rapidly.

23% over 55

These petroleum drivers are 10 years or fewer from retirement age. 8% of these over-55 truck drivers are already past retirement age but still working.

CONTACT
National Tank Truck Carriers, Inc. | 950 North Glebe Rd. Suite 520 | Arlington, VA 22203 | 703.838.1960 | nttcstaff@tanktruck.org | www.tanktruck.org

SOURCES
Drivers Wanted - Using data to understand the commercial truck driver shortage, Emsi/Coyote Logistics 2021 I NTTC Questionnaire of leading U.S. petroleum haulers, 2021

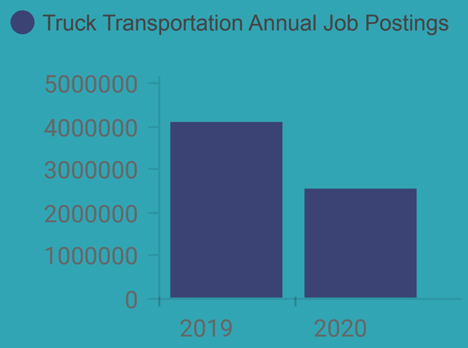
NATIONAL TANK TRUCK CARRIERS

PETROLEUM DRIVER SHORTAGE

PANDEMIC EFFECT

The effects of the pandemic and accompanying response have been massive. For petroleum carriers, and the trucking industry at large, it has only served to escalate an already growing driver shortage. DMV and driving school closures as part of the pandemic response created a void of new drivers entering the workforce.

Trucking overall saw a 38% decrease in job postings in 2020. Because of lockdowns and travel restrictions, the petroleum hauling sector was uniquely hard hit. The subsequent decrease in fuel consumption led many drivers close to retirement age to retire early, while others were furloughed due to a lack of work. This has dramatically exacerbated the driver shortage issue as economic conditions have quickly recovered in 2021.



BARRIERS TO ENTRY

UNIQUE TO PETROLEUM, HAZMAT TRUCKING

IMAGE ISSUE
Lifestyle of truck drivers still marred in the eyes of the general public

CERTIFICATIONS
Hazmat, TWIC (same info to 2 agencies), training required at each loading facility

EB-3 VISAS
Needs fast-tracking for hiring experienced immigrant drivers

AGE REQUIREMENTS
Must be 21 for Interstate CDL, 23 to deliver hazmat

D&A CLEARINGHOUSE
As of April 1, more than 50K drivers in prohibited status with at least 1 violation

COLONIAL PIPELINE SHUTDOWN

The Colonial Pipeline shut down for 5 days (May 7-12, 2021) due to a ransomware attack. This caused fuel shortages, panic buying and price spikes that highlighted weaknesses in our petroleum supply chain. The U.S. is one natural or manmade disaster away from collapse. A lack of petroleum drivers plays a significant role in these weaknesses.

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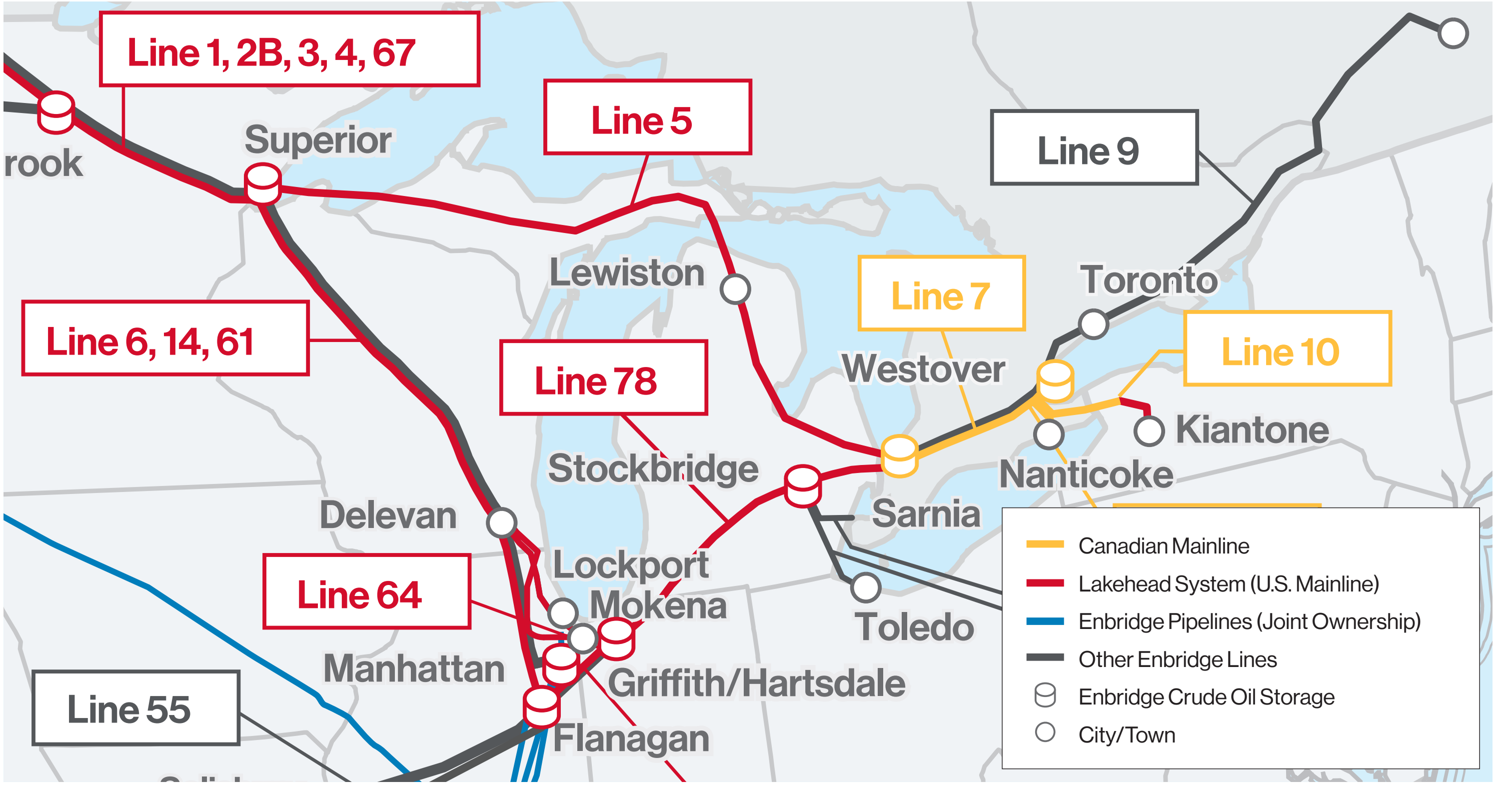


The impact of a Line 5 shutdown

Enbridge's Line 5 has been a vital piece of energy infrastructure since 1953—not just for Michigan, but for the entire U.S. Midwest and points beyond.

For more than 65 years, Line 5 has delivered the light oil and natural gas liquids (NGL) that heat homes and businesses, fuel vehicles and power industry.

Shutting down Line 5, even temporarily, would have immediate and severe consequences on the economies of Michigan, Ohio, Ontario, and elsewhere.

Enbridge's Line 5 is a 645-mile, 30-inch-diameter pipeline that travels through Michigan's Upper and Lower Peninsulas—originating in Superior, Wisconsin, and terminating in Sarnia, Ontario, Canada.

Line 5 transports up to 540,000 barrels per day (bpd), or 22.68 million US gallons per day, of light crude oil, light synthetic crude and natural gas liquids (NGLs), which are refined into propane.

Line 5 supplies 65% of propane demand in Michigan's Upper Peninsula, and 55% of Michigan's statewide propane needs. The light crude transported by Line 5 feeds refineries in the Upper Midwest and Eastern Canada.

If Line 5 were shut down*:

- Refineries served by Enbridge in Michigan, Ohio, Pennsylvania, Ontario and Quebec **would receive approximately 45% less crude from Enbridge** than their current demand.
- Michigan would face a **756,000-US-gallons-a-day propane supply shortage**, since there are no short-term alternatives for transporting NGL to market.
- The region (Michigan, Ohio, Pennsylvania, Ontario and Quebec) would see a **14.7-million-US-gallons-a-day supply shortage of gas, diesel and jet fuel** (about 45% of current supply).
- Michigan would need to f**ind an alternative supply for anywhere from 4.2 million to 7.77 million US gallons of refined products** (gas, diesel, jet fuel and propane).

Alternatives for the above shortages are limited—and that would mean massive investment in pipeline infrastructure, or significantly increasing rail or trucking capacity, to make up for the shortfall caused by a Line 5 shutdown.

*Estimates are based on current market conditions, and contingent on similar energy demands in the future (crude oil demand is not expected to see an appreciable change)

ENBRIDGE
Life Takes Energy

Toll-free: **1-855-869-8209**
E-mail: **line5info@enbridge.com**

The effects of a Line 5 shutdown

Shutting down Line 5, even temporarily, would have a major and immediate impact on crude oil supply for refineries—and, as a result, refined product supply for consumers, motorists and industry.

Crude oil impacts

Regional **crude oil and NGL demand** on Enbridge's Line 5 and Line 78 totals about **40.74 million US gallons a day.**

Demand for crude is not expected to change any time soon—and with Enbridge's pipeline system already essentially full, a Line 5 shutdown would cause federally regulated apportionment, or reduction in deliveries, on our Line 78 by approximately 45%.

In other words, refineries in Michigan, Ohio, Pennsylvania, Ontario and Quebec **will receive approximately 45% less crude from Enbridge** than their current demand.

Refined products impacts

Michigan uses about **15.75 million US gallons of transportation fuel (gas, diesel and jet fuel) every day**—and with Detroit's refining capacity meeting only about 25% of that demand, Michigan relies heavily on surrounding states like Ohio, Illinois and Indiana for its refined products.

A Line 5 shutdown would cause a **shortfall of 14.7 million US gallons of transportation fuel a day** (that's 45% of the current Enbridge supply in Michigan, Ohio, Pennsylvania, Ontario and Quebec) and a **Michigan propane shortage of 756,000 US gallons a day** (or 55% of the current supply).

That means Michigan would **need to find more than 4.2 million US gallons a day of gas, diesel, jet fuel and propane** to make up for the shortfall—assuming Ohio and other regional refineries are receiving crude oil from Line 78 at an apportioned rate of approximately 55%. If those refineries are unable to meet local needs, and stop supplying Michigan, then **that number would rise to 7.77 million US gallons a day.**

The effect on regional refineries

According to PBF Energy, which operates one of two refineries in Toledo:

- A Line 5 shutdown would put Ohio refineries at risk. The closure of one of those refineries could result in the loss **of $5.4 billion in annual economic output** to Ohio and southeast Michigan, and the **loss of thousands of direct and contracted skilled trades jobs.**
- A Line 5 shutdown would compromise crude supply to 10 refineries in the region to varying degrees, **directly affecting fuel prices.**
- Closing Line 5 would **hurt Ohio and Michigan economies**, and **threaten union jobs.**
- There are **no viable options for replacing** the volume of light crude delivered by Line 5, with **rail able to provide less than 10%** of that volume.
- A Line 5 shutdown puts **at least 15% of northwest Ohio's fuel supply at risk**, as well as more than **half of the jet fuel supplies** for the Detroit Metro Airport.

Demand on Enbridge pipelines (approximate)

Line	Kbpd	US gallons per day
Line 5 (including NGL)	500	21,000,000
Line 78	470	19,740,000
Total	**970**	**40,740,000**

Capacity of Enbridge pipelines

Line	Kbpd	US gallons per day
Line 5	540	22,680,000
Line 78	570	23,940,000
Line 78 (ex-Stockbridge)	502	21,084,000

ENBRIDGE
Life Takes Energy®

Toll-free: **1-855-869-8209**
E-mail: **line5info@enbridge.com**

Oil Market Highlights

Crude Oil Price Movements

Crude oil prices rebounded m-o-m in September, gaining about 5%, supported by robust oil market fundamentals amid a slow restart of US oil production, further recovery of oil demand and a drop in inventories, along with easing COVID-19-related mobility restrictions in several Asian countries. Moreover, worries about natural gas and coal shortages in Europe and Asia boosted sentiment for higher oil demand. The OPEC Reference Basket (ORB) value rose by $3.55 or 5.0% m-o-m in September to settle at $73.88/b. Year-to-date (y-t-d), the ORB was up by $26.21, or 64.5%, to average $66.83/b compared with the same period last year. The ICE Brent front-month rose $4.37, or 6.2%, m-o-m in September to average $74.88/b, while NYMEX WTI increased by $3.83, or 5.7%, m-o-m to average $71.54/b. Consequently, the Brent/WTI spread widened further in September to $3.34/b, its highest point since last April. The market structure of all three major oil benchmarks – Brent, WTI and Dubai – remained in backwardation. However, the Brent forward curve strengthened, while WTI and Dubai backwardation flattened slightly. Hedge funds and other money managers boosted bullish wagers in September as oil prices rose to multi-year highs, as the risk of a natural gas and coal shortage urged speculators to bet on higher oil prices.

World Economy

Global economic growth forecasts for both 2021 and 2022 remain unchanged from the last month's assessment at 5.6% and 4.2%, respectively. Given somewhat slowing 3Q21 momentum, the US economy forecast for 2021 is revised down slightly to 5.8% from 6.1%, while the forecast for 2022 remains unchanged at 4.1%. Euro-zone economic growth is revised up to 5% from 4.7% for 2021 and to 3.9% from 3.8% for 2022, after a strong rebound in 2Q21. The forecast for Japan is revised down to 2.6% from 2.8% for 2021, due to ongoing COVID-19-related social-distancing measures in 3Q21, while the forecast for 2022 remains at 2%. After a strong recovery in the first half of the year, China's economy is seen to slow somewhat, leaving the growth forecast at 8.3% in 2021 and 5.8% in 2022, representing a 0.2 percentage point downward revision for both years. Meanwhile, India's 2021 growth forecast is unchanged at 9% for 2021 and 6.8% for 2022, although downside risks prevail. Russia's forecasts are revised up from 3.5% to 4% for 2021 and from 2.5% to 2.7% for 2022, benefitting from the more stable oil market. Brazil's growth forecast remains unchanged for both 2021 and 2022 at 4.7% and 2.5%, respectively. The ongoing robust growth in the world economy continues to be challenged by uncertainties, such as the spread of COVID-19 variants and the pace of vaccine rollouts worldwide, as well as ongoing global supply-chain disruptions. Additionally, sovereign debt levels in many regions, together with rising inflationary pressures and potential central bank responses, remain key factors requiring close monitoring.

World Oil Demand

World oil demand is estimated to increase by 5.8 mb/d in 2021, revised down from 5.96 mb/d in the previous month's assessment. The downward revision is mainly driven by lower-than-expected actual data for the first three quarters of this year, despite healthy oil demand assumptions going into the final quarter of the year, which will be supported by seasonal uptick in petrochemical and heating fuel demand and the potential switch from natural gas to petroleum products due to high gas prices. Both OECD and non-OECD figures are adjusted lower, with the downward revision in OECD regions focused in 1H21, while the non-OECD revision is concentrated in 3Q21.The world is expected to consume 96.6 mb/d of petroleum products this year. For 2022, world oil demand growth is unchanged at 4.2 mb/d. As a result, global demand next year is seen averaging 100.8 mb/d. Demand is anticipated to be supported by healthy economic momentum in the main consuming countries and better management of the COVID-19 pandemic.

World Oil Supply

Non-OPEC liquids supply growth in 2021 is revised down by 0.3 mb/d from the previous month's assessment to now stand at 0.7 mb/d. The revisions were driven mainly by a downward adjustment in 3Q21 due to factors such as production outages in the US Gulf of Mexico caused by Hurricane Ida; maintenance in the Tengiz field in Kazakhstan; and a force majeure in Canada at the Suncor oil sands site. The impact of the Hurricane led to a downward revision in US liquids supply in 2021 from growth of 0.1 mb/d to a contraction of 0.1 mb/d. The main growth drivers for 2021 supply growth continue to be Canada, Russia, China, Norway and Brazil. Similarly, the non-OPEC supply growth forecast for 2022 is revised up by 0.1 mb/d due to the base change to now stand at 3.0 mb/d. Russia and the US are expected to be the main drivers, followed by Brazil, Norway, Canada, Kazakhstan, Guyana, and other countries in the DoC. OPEC NGLs are forecast to grow by 0.1 mb/d in both 2021 and 2022 to average 5.2 mb/d and 5.3 mb/d, respectively. OPEC crude oil production in September increased by 0.49 mb/d m-o-m, to average 27.33 mb/d, according to available secondary sources.

Product Markets and Refining Operations

Refinery margins further extended their upward trend in September globally, with solid support coming from the middle of the barrel. The tightness in product balance caused by supply side constraints in previous months was exacerbated by the start of peak refinery maintenance season amid lower product exports from China. Middle distillates were the main margin driver in all regions, while in Asia this upside was outpaced by robust fuel oil performance. Meanwhile, gasoline markets weakened as their crack spreads stepped down from post-pandemic highs registered the previous month, due to a less optimistic demand outlook as peak driving season approached its end.

Tanker Market

Dirty tanker rates remained soft in September amid a continued imbalance between tonnage supply and demand, keeping rates at low or even loss-making levels. Meanwhile, some positive signs are emerging for the final quarter of the year, as loading schedules should see a 20% increase in waterborne Russian exports and 10% increase in North Sea flows, amid ongoing planned upward adjustments in OPEC production. However, a sustained recovery in the tanker market could take as long as 12 months to materialize to allow for a return in demand from emerging and developing markets and sufficient scrapping to reduce the overhang in tonnage availability.

Crude and Refined Products Trade

Preliminary data shows US crude imports in September recovering from a slight dip the month before to average a healthy 6.4 mb/d, while US crude exports averaged 2.6 mb/d in September, continuing an alternating pattern of rises and dips, this time on the lower side. After four months of relatively muted levels, China’s crude imports jumped to 10.5 mb/d in August, pushed higher by the arrival of storm-delayed cargoes, although policy-led uncertainties continued to impact China’s trade flows. India’s crude imports finally saw a recovery, after following a general downward trend since December 2020, to average 4.1 mb/d in August. Tanker tracking data show India’s crude imports remaining steady in September. Japan’s crude imports continued to recover from low levels, reaching their highest point since April 2020 at 2.7 mb/d in August. The country’s crude and product imports are expected to see a boost from demand in the power sector for fuel oil as well as crude for direct burning, amid reports of a restart of oil-fired power units.

Commercial Stock Movements

Preliminary August 2021 data showed that total OECD commercial oil stocks fell by 19.5 mb m-o-m to stand at 2,855 mb. This was 363 mb lower than the same time one year ago, 183 less than the latest five-year average and 131 mb below the 2015-2019 average. Within components, OECD commercial crude stocks fell by 23.0 mb m-o-m in August, ending the month at 1,362 mb. This was down by 102 mb compared with the latest five-year average, and 87 mb below the 2015-2019 average. By contrast, OECD total product inventories rose by 3.2 mb m-o-m in August to stand at 1,493 mb. This was 81 mb lower than the latest five-year average and 43 mb below the 2015-2019 average. In terms of days of forward cover, OECD commercial stocks fell by 0.1 days m-o-m in August to stand at 62.5 days. This was 12.3 days lower than the same period in 2020, 2.5 days below the latest five-year average and 0.3 days below the 2015-2019 average.

Balance of Supply and Demand

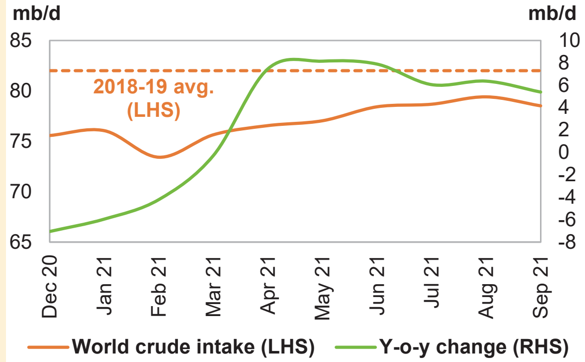
Demand for OPEC crude in 2021 is revised up by 0.1 mb/d from the previous month’s assessment to stand at 27.8 mb/d, around 5.0 mb/d higher than in 2020. Demand for OPEC crude in 2022 was also revised up by 0.1 mb/d from the previous month’s assessment to stand at 28.8 mb/d, around 1.0 mb/d higher than in 2021.

Feature Article

Winter oil market outlook

Following the outbreak of COVID-19 and resulted lockdown measures in 2020, refined oil product consumption, along with refinery intakes, recovered considerably in 2021. As road transportation fuel demand picked up during the summer season this year, and petrochemical feedstock requirements increased, refinery intakes in August rose by 6.4 mb/d, compared with the same month a year earlier. This marks a significant measure ahead of the usual refinery maintenance season beginning in September, and corresponds to a hefty 10.5 mb/d increase relative to levels seen in May 2020. Despite this considerable recovery, intakes in August still remain nearly 2.5 mb/d below the pre-pandemic 2018-2019 average of 82 mb/d (***Graph 1***).

Graph 1: Refinery intake by region



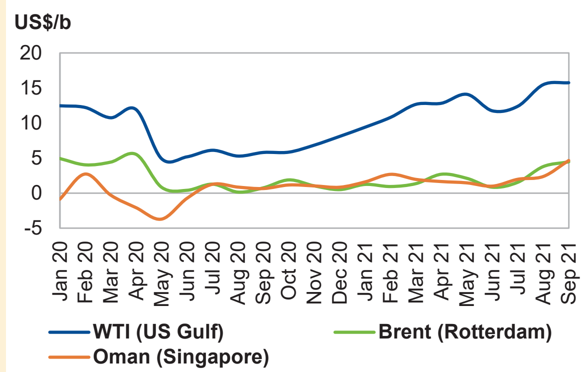
Source: OPEC.

Refinery utilization rates in 2021 have been firmly supported by stronger product fundamentals with robust gasoline performance, mainly in the US and Europe, leading to strong conversion margins in recent months and, ultimately, solid improvement in refining economics (***Graph 2***).

The recovery in transportation fuels, as well as in the naphtha segment, was mostly driven by stronger consumption levels and robust economic activity amid improved mobility indicators. At the same time, cautious management of refinery intakes in an attempt to prevent product oversupply, amid a rise in unplanned outages during the hurricane season in the US, contributed to an increasingly stronger product balance and further supported product markets and refining economics in recent months.

These supply-side constraints ultimately drove product prices to soar to post-pandemic record highs, with gasoline prices in the US in reaching a multi-year record high of $99.50/b in July, compared with $52.51/b a year earlier and $88.55/b in July 2019.

Graph 2: Refinery margins



Sources: Argus and OPEC.

Refinery offline capacity began its seasonal rise in September, up by 891 tb/d m-o-m, according to preliminary estimates. Based on historical data and announced maintenance plans, the rise in offline capacity is projected to peak at around 9.3 mb/d in October, compared with 6.1 mb/d seen in August, before the onset of maintenance.

At the same time, the renewed spread of COVID variants continues to pose a downside risk to product markets, despite the positive vaccination rollout progress, particularly with regard to air travel and jet fuel markets, the hardest pandemic-hit product segment, which has yet to fully recover.

Recently, soaring natural gas prices, which have reached record-high levels, particularly in Europe during September, have triggered a growing interest in switching from natural gas to liquid fuels at the industrial level, as energy companies attempt to drive down cost. Should this trend continue, fuels such as fuel oil, diesel, and naphtha could see support, driven by higher demand from power generation, refining and petrochemical use. On the other hand, record high natural gas prices have pushed electricity costs and, consequently, refining operational costs higher. This could weigh on refinery intakes and industrial production and partially offset the upside potential. Forecasts for a colder-than-average winter in 4Q21 could set the stage for positive support for heating oil markets, particularly in December, but this could be offset by seasonal weakness from other key products across the barrel, particularly gasoline.

Looking ahead, despite expectations of a seasonal pick-up in heating oil demand, as well as a potential switch from natural gas to liquid fuels, product markets are expected to see some weakness during the coming winter due to higher refinery throughput leading to ample supply. Although refineries are expected to increase run rates in line with seasonal trends to replenish stocks, any considerable growth in global intake levels could pose a challenge to product markets. Meanwhile, concerns of potential renewed COVID-19-related mobility restrictions during the winter could weigh on product markets and, consequently, refinery intakes. Thus, as oil markets continue to emerge from the COVID-19 pandemic, countries participating in the Declaration of Cooperation continue to maintain a vigilant watch over market fundamentals in an ongoing effort to support balance in oil market.

World Oil Demand

In 2021, world oil demand is estimated to increase by 5.8 mb/d y-o-y compared with 6.0 mb/d last month. Despite positive assumptions on oil demand going into the final quarter of the year, supported by seasonal petrochemical and heating fuel demand as well as the potential of switching from natural gas to oil in the power generation sector, the downward revision mainly takes into account actual data. Both OECD and non-OECD figures were adjusted lower; while the downward revision in OECD regions focused on 1H21, non-OECD revisions were concentrated in 3Q21.The world is anticipated to consume 96.6 mb/d of petroleum products during the current year.

In the OECD, demand was revised lower by more than 0.11 mb/d in 2021, mainly to account for actual data. Lower-than-expected demand data for 1Q21 and 2Q21 in OECD Americas and OECD Europe was seen due to lower-than-anticipated transportation and industrial fuel demand.

In the non-OECD, 2021 oil demand outlook was revised lower by around 0.03 mb/d compared with the previous MOMR, amid lower-than-expected data from China and India in 3Q21. The resurgence of COVID-19 cases reduced mobility in China during August, while the demand recovery in India was slower than initially anticipated.

In 2022, world oil demand growth was kept unchanged compared with last month’s estimates at 4.2 mb/d. Total global demand is foreseen reaching 100.8 mb/d for the year. The main oil demand assumption remains as highlighted last month, with healthy economic momentum in the main consuming countries and better COVID-19 management. For 2022, the oil demand outlook takes into consideration an increase of 4.2% in economic activity with COVID-19 pandemic-related risks well managed due to higher vaccination rates and better treatment. In terms of products, gasoline and diesel are estimated to increase the most, supported by an ongoing recovery in mobility and improving industrial activity.

Table 4 - 1: World oil demand in 2021*, mb/d

							Change 2021/20	
World oil demand	**2020**	**1Q21**	**2Q21**	**3Q21**	**4Q21**	**2021**	**Growth**	**%**
Americas	22.60	22.77	24.56	25.15	24.73	24.31	1.71	7.55
of which US	*18.51*	*18.69*	*20.21*	*20.53*	*20.46*	*19.98*	*1.47*	*7.96*
Europe	12.44	11.90	12.60	13.71	13.69	12.99	0.55	4.42
Asia Pacific	7.14	7.67	7.04	7.17	7.57	7.36	0.22	3.10
Total OECD	**42.18**	**42.34**	**44.19**	**46.03**	**45.99**	**44.66**	**2.48**	**5.87**
China	13.20	13.15	14.32	14.63	15.02	14.28	1.08	8.17
India	4.51	4.94	4.50	4.77	5.57	4.95	0.44	9.70
Other Asia	8.13	8.36	8.98	8.49	8.62	8.61	0.48	5.93
Latin America	6.01	6.15	6.16	6.54	6.40	6.31	0.30	5.02
Middle East	7.55	7.95	7.77	8.24	7.97	7.99	0.44	5.84
Africa	4.06	4.35	4.06	4.16	4.44	4.25	0.19	4.66
Russia	3.37	3.57	3.42	3.61	3.74	3.58	0.22	6.44
Other Eurasia	1.07	1.18	1.24	1.14	1.28	1.21	0.14	12.70
Other Europe	0.70	0.78	0.72	0.73	0.79	0.75	0.06	8.29
Total Non-OECD	**48.60**	**50.44**	**51.17**	**52.30**	**53.83**	**51.94**	**3.34**	**6.87**
Total World	**90.79**	**92.77**	**95.36**	**98.33**	**99.82**	**96.60**	**5.82**	**6.41**
Previous Estimate	90.73	92.82	95.62	98.46	99.70	96.68	5.96	6.56
Revision	0.06	-0.04	-0.26	-0.13	0.12	-0.08	-0.14	-0.15

*Note: * 2021 = Forecast. Totals may not add up due to independent rounding. Source: OPEC.*

Table 4 - 2: World oil demand in 2022*, mb/d

World oil demand	2021	1Q22	2Q22	3Q22	4Q22	2022	Change 2022/21 Growth	%
Americas	24.31	24.10	25.66	26.17	25.53	25.38	1.07	4.39
of which US	*19.98*	*19.75*	*21.09*	*21.50*	*21.18*	*20.89*	*0.91*	*4.54*
Europe	12.99	12.55	13.27	14.32	14.17	13.59	0.60	4.61
Asia Pacific	7.36	7.91	7.22	7.30	7.68	7.53	0.17	2.27
Total OECD	**44.66**	**44.56**	**46.15**	**47.79**	**47.39**	**46.49**	**1.83**	**4.10**
China	14.28	14.00	15.20	15.12	15.46	14.95	0.66	4.65
India	4.95	5.40	4.90	5.15	5.89	5.34	0.39	7.90
Other Asia	8.61	9.05	9.59	9.07	8.95	9.16	0.55	6.39
Latin America	6.31	6.39	6.34	6.69	6.56	6.50	0.18	2.89
Middle East	7.99	8.29	8.01	8.49	8.20	8.25	0.26	3.31
Africa	4.25	4.53	4.19	4.28	4.57	4.39	0.14	3.29
Russia	3.58	3.67	3.47	3.66	3.79	3.65	0.07	1.82
Other Eurasia	1.21	1.25	1.29	1.17	1.32	1.26	0.05	3.72
Other Europe	0.75	0.80	0.73	0.74	0.81	0.77	0.02	2.18
Total Non-OECD	**51.94**	**53.39**	**53.73**	**54.38**	**55.54**	**54.26**	**2.32**	**4.46**
Total World	**96.60**	**97.95**	**99.88**	**102.16**	**102.93**	**100.76**	**4.15**	**4.30**
Previous Estimate	96.68	97.99	100.15	102.29	102.81	100.83	4.15	4.29
Revision	-0.08	-0.04	-0.26	-0.13	0.12	-0.08	0.00	0.00

*Note: * 2021-2022 = Forecast. Totals may not add up due to independent rounding. Source: OPEC.*

OECD

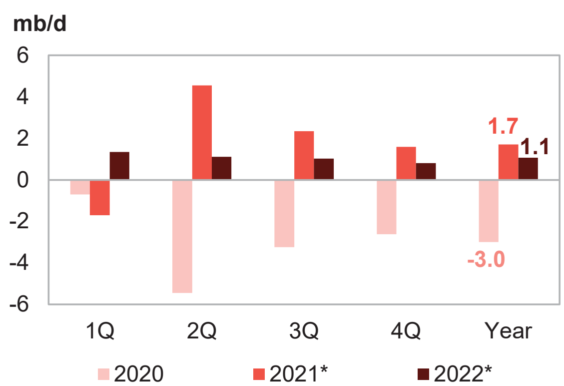
OECD Americas

Update on the latest developments

The latest available oil demand data in **OECD Americas** implies a y-o-y increase of 2.0 mb/d y-o-y in **July**, following an increase of 3.1 mb/d y-o-y in June. Gasoline demand remained robust during the traditional travelling period in the region and accounted for around 42% of the overall increase, while jet/kerosene demand accounted for 30%. These developments make up approximately 77% of the losses during the same month in 2020, while during the first seven months of 2021 the recovery stood at only 45%. In July 2021, gasoline demand continued to grow for the fifth month in a row, posting gains of around 0.9 mb/d y-o-y. Oil demand continued to remain below July 2019 levels, with a differential of 1.3 mb/d. All countries in the region posted solid demand gains.

The latest available US monthly demand data for July imply increasing oil demand by approximately 1.5 mb/d y-o-y, making up 64% of losses incurred during July 2020, though remaining lower than July 2019 by 0.8 mb/d. Gasoline, jet/kerosene and diesel requirements contributed the most to this increase, with y-o-y gains by gasoline of 0.9 mb/d, jet kerosene of 0.5 mb/d and on-road diesel of 0.3 mb/d (total diesel demand increased by 0.04 mb/d). Demand for these three transportation-related fuels fell sharply during July 2020, by 1.3 mb/d, 0.8 mb/d and 0.4 mb/d y-o-y, respectively. According to the Federal Highway Administration, vehicle miles of travel in the US increased by 13.1% y-o-y in July 2021 after rising by 14.9% y-o-y in June. In July 2020, the indicator fell by 12.6% y-o-y.

Graph 4 - 1: OECD Americas oil demand, y-o-y change



*Note: * 2021-2022 = Forecast. Source: OPEC.*

Light vehicle retail sales, as reported by Autodata and Haver Analytics, were at 14.7 million units according to seasonally adjusted annual rates (SAAR), compared with 15.4 million units in June. In July of last year, total sales were at 14.7 million units and 17.1 million units were sold in July 2019. Industrial production was also higher by 6.6% y-o-y in July after increasing by 10.0% y-o-y in June. Preliminary data for August, based on weekly data, indicate the continuation of a recovery in transportation fuel performance, with both gasoline and jet kerosene demand increasing by more than 1.4 mb/d y-o-y in total.

Table 4 - 3: US oil demand, mb/d

			Change	*Jul 21/Jul 20*
By product	**Jul 20**	**Jul 21**	**Growth**	**%**
LPG	2.79	2.86	0.06	2.2
Naphtha	0.20	0.22	0.02	7.5
Gasoline	8.46	9.31	0.85	10.1
Jet/kerosene	0.97	1.49	0.52	54.0
Diesel	3.62	3.66	0.04	1.2
Fuel oil	0.35	0.33	-0.02	-5.5
Other products	2.29	2.32	0.04	1.6
Total	**18.67**	**20.18**	**1.51**	**8.1**

Note: Totals may not add up due to independent rounding. Sources: EIA and OPEC.

OECD Americas recovered swiftly in 1H21 from the historical decline in 2020. Oil demand showed a strong rebound by around 1.4 y-o-y, with data from **January to July** compared with the same period last year. However, this increase was around 1.7 mb/d lower than the demand recorded during the same period in 2019. The recovery is led by strongly rebounding demand in the US, despite a weak start to the year, with rising infection figures limiting mobility and consumption for transportation fuels. Demand has improved, posting strong gains supported by an acceleration in vaccination programmes in the US, which led to improved miles travelled in addition to progressing industrial production activities, supporting demand for industrial fuels. Elsewhere in the region, demand in Canada continued to decline as heavy distillates weighed negatively on overall fuel performance, while Mexican demand was marginally higher, supported by additional demand for fuel oil. Despite a distorted baseline of comparison, demand for gasoline led gains in OECD America, as mobility indicators continued to trend higher during the first part of the year, with a respectable uptick in aviation activity towards the end of 2Q21. Both fuels increased by around 0.9 mb/d y-o-y from January to July. It’s worth highlighting that both fuels declined sharply during the same period compared with 2019 amid the onset of COVID-19 and subsequent prevalence of government measures reducing movement and limiting mobility, resulting a massive drop in transportation fuel demand of around 2.4 mb/d y-o-y. Additionally, healthy petrochemical margins were supported by steady end-user demand, particularly from the health sector, as well as the ramping up of new ethane cracker capacity, which supported demand for light distillates. LPG and naphtha demand increased by around 0.2 mb/d y-o-y compared with the same period last year. This is compared with a decline of around 0.1 mb/d y-o-y in 1H20 over the same period in 2019. Diesel was up by more than 0.1 mb/d compared with 2020, supported by steady industrial demand. Most gains appeared in the US, supported by stimulus programmes and improving industrial momentum compared with the same period in 2020. Diesel demand in Canada showed a marginal increase, while posting a decline in Mexico.

Near-term expectations

Going forward, overall COVID-19 pandemic developments support optimism for short term oil demand prospects in the region. The economy is expected to remain strong, supported by various stimulus programmes. Some downside risks are linked to COVID-19 developments during the emergence of colder weather in 4Q21 and possible localized government countermeasures. Meanwhile, 3Q21 remains robust in terms of travelling activities and limited downside risks only arise from the impact of COVID-19 on consumer behavior, as well as the effectiveness of vaccination programmes.

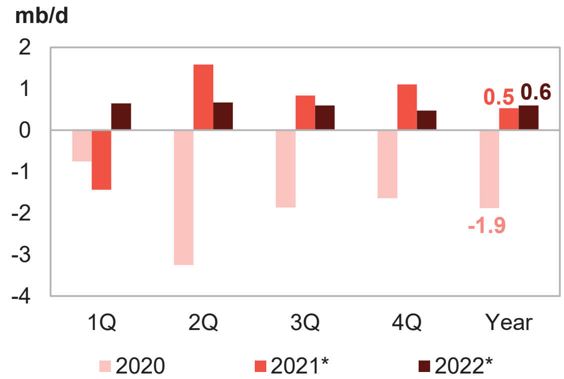
In **2022**, OECD Americas oil demand is expected to receive strong support from an encouraging short-term economic outlook, boosting oil demand by around 1.1 mb/d y-o-y, with US oil demand accounting for 0.9 mb/d y-o-y. Petrochemicals and transportation will remain the sectors requiring more oil in 2022. Gasoline demand will be backed by an increase in vehicle sales, while expansion in the petrochemical industry will provide support to light distillates in 2022. On the other hand, some challenges remain, such as COVID-19 pandemic developments, a continuation of fuel substitution programmes and fuel efficiency gains.

OECD Europe

Update on the latest developments

OECD Europe's oil demand increased by 0.7 mb/d, y-o-y, in **July**, following an increase of 1.6 mb/d, y-o-y, in June, implying a recovery rate of 34.1%. Demand for all petroleum product categories showed y-o-y gains, as a result of the low historical baseline and increasing regional travelling activities in line with the removal of restrictions and amid warmer weather. The strongest gains were for jet kerosene, light distillates, gasoline and diesel. On top of a low historical baseline, demand for jet kerosene marked the strongest monthly recorded growth in history, y-o-y, and remained on a growing trajectory since April 2021, in line with rising travelling activities. Demand for transportation fuels shows gains since April 2021.

Graph 4 - 2: OECD Europe's oil demand, y-o-y change



*Note: * 2021-2022 = Forecast. Source: OPEC.*

In July, demand in the UK grew by 0.2 mb/d, while requirements in Italy and France increased by 0.1 mb/d, though in Germany they fell by 0.1 mb/d y-o-y. Oil demand gains were eminent in all other countries of the region, coupled with travel across and within country borders. The industrial production index, which excludes construction, rose by 8.0% compared with the same month in 2020, as reported by Eurostat and Haver Analytics. New passenger car registrations fell by 23.9% y-o-y, following a 11.3% y-o-y increase in June.

From January to July, European oil demand showed a modest increase of around 0.1 mb/d y-o-y compared with the same period in 2020, mainly because the recovery from 2020's oil demand slump was affected by a slow start to the year due to a resurgence of COVID-19 cases in 1Q21, forcing the reintroduction of lockdown measures across many economies in the region. Within the big four consuming countries, demand performance was mixed. Demand in Italy and France showed decent gains of around 0.2 mb/d and 0.1 mb/d y-o-y, respectively. UK demand increased marginally, while in Germany demand declined by a hefty 0.2 mb/d. In the OECD region as a whole, increases in oil demand were attributed to gasoline, on road diesel and light distillates. An easing of measures to control the spread of COVID-19 resulted in improving oil demand across the region, with significant variation between countries. This can be illustrated in the mobility index, which reported increases of 66% from pre-pandemic levels in January to 128% in July and August. Preliminary data suggests further increases. Within countries, Italy and France showed the highest gains during the month of July, supported by an easing of restriction measures, as well as summer seasonal driving. The index was at 127% in Italy and 116% in France. Gasoline increased by more than 0.1 mb/d y-o-y in 1H21 compared with a massive y-o-y drop during the same period of 2020 of 0.3 mb/d. Industrial production, an indicator for industrial fuel demand, also showed gains during 1H21. As reported by the Statistical Office of the European Communities and Haver Analytics, the indicator increased by around 104.9 during 1H21 compared with 93.5 during the same period in 2020. The index uses 2015 as a reference. It's worth knowing that diesel (including on-road diesel) and fuel oil dropped by around 0.7 mb/d y-o-y during the peak days of the pandemic in 2020 (January-July), while data from January-July 2021 show both fuels recovered only 0.1 mb/d of last year losses.

Table 4 - 4: Europe's Big 4* oil demand, mb/d

			Change Jul 21/Jul 20	
By product	**Jul 20**	**Jul 21**	**Growth**	**%**
LPG	0.42	0.41	-0.01	-2.6
Naphtha	0.57	0.55	-0.01	-2.1
Gasoline	1.16	1.22	0.06	4.8
Jet/kerosene	0.32	0.47	0.15	47.8
Diesel	3.13	3.18	0.05	1.5
Fuel oil	0.18	0.18	0.00	-0.5
Other products	0.50	0.51	0.01	1.2
Total	**6.28**	**6.51**	**0.24**	**3.8**

*Note: * Germany, France, Italy and the UK. Totals may not add up due to independent rounding.*

Sources: JODI, UK Department for Business, Energy & Industrial Strategy, Unione Petrolifera and OPEC.

Near-term expectations

Going forward, the outlook for the region's oil demand for the rest of the year 2021 has improved since last month, amid COVID-19 containment efforts, increasing vaccination rates and falling cases; 3Q21 has proven to be robust and warmer weather favoured oil demand developments. The current outlook assumes that the pandemic will largely remain controlled in the coming months, supporting transportation fuel demand. The petrochemical sector will also be supported by seasonality factors, with naphtha being favoured due to its price advantage. A further upside could stem from high gas prices incentivising a switch to oil-based fuels largely in the power-generation sector. However, this upside is anticipated be limited and dependant on the severity of the winter season.

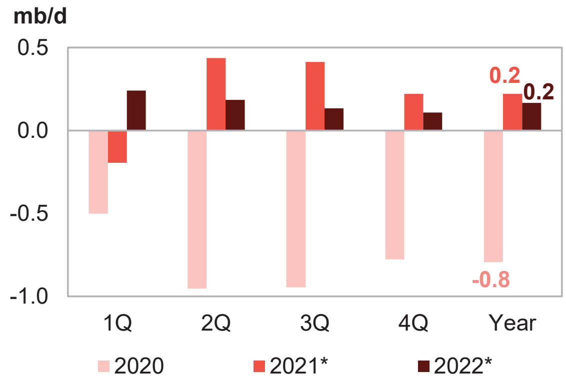
In **2022**, OECD Europe's oil demand is expected to rise by around 0.6 mb/d. Positive projections for the economy, along with the containment of COVID-19, are the main factors supporting OECD Europe oil demand growth in 2022. Improvements in mobility, along with positive developments in the industrial and construction sectors, are expected to raise oil demand in the transportation and industrial sectors. Downside risks are related to COVID-19, as well as high debt levels and budgetary constraints in almost every country in the region.

OECD Asia Pacific

Update on the latest developments

OECD Asia Pacific oil demand increased by 0.3 mb/d, y-o-y in **July**, less than the corresponding increases recorded in June of 0.4 mb/d. Gains were largely attributed to rising light distillate requirements in South Korea as well as gasoline and diesel demand in all countries of the region. Oil demand gained additional strength from the Summer Olympics in Japan. Demand for light distillates in Asia Pacific during July grew by 0.1 mb/d y-o-y after increasing by 0.2 mb/d in June. Transportation fuel demand was flat y-o-y in July, following gains of 0.2 mb/d in June y-o-y. Oil demand in Japan and South Korea grew by 0.2 mb/d y-o-y. Preliminary data from by Japan's Ministry of Economy, Trade and Industry (METI), indicate flat oil demand in August y-o-y.

Graph 4 - 3: OECD Asia Pacific oil demand, y-o-y change



*Note: * 2021-2022 = Forecast. Source: OPEC.*

Between **January and July**, oil demand increased by about 0.1 mb/d y-o-y in the whole **OECD Asia Pacific** region compared with a decline of around 0.8 mb/d during the same period in 2020. Demand also declined compared with the same period of 2019 by around 0.7 mb/d. The recovery from the 2020 slump in oil demand was affected by an increase in infection cases in Japan and South Korea and most recently Australia and New Zealand, as regional restrictions remained in place for most of 2021, despite marginal support from the summer Olympic Games in Japan. The recovery process was rather slow, with jet fuel declining further from 2020 levels. OECD Asia Pacific light distillate demand increased by around 0.1 mb/d y-o-y during 1H21, supported by a low baseline, healthy end-user consumption for plastics and the return of naphtha crackers from maintenance, particularly in South Korea. Demand for light distillates was at par with 2019 levels. Regarding transportation fuels, both gasoline and jet fuel were lower than 2019 levels, however gasoline increased y-o-y by around 0.05 mb/d as road mobility improved in Japan to slightly above pre-pandemic levels, though remaining below 2019 levels in South Korea. According to google maps and Apple apps, the index increased from 86% of pre-pandemic levels in Japan in January to 112% in July. Meanwhile, in South Korea the index was at 71% of pre-pandemic levels in January and 89% in July.

Table 4 - 5: Japan's oil demand, mb/d

By product	Aug 20	Aug 21	Change Aug 21/Aug 20 Growth	%
LPG	0.33	0.31	-0.03	-8.1
Naphtha	0.69	0.69	0.00	0.4
Gasoline	0.85	0.79	-0.06	-6.6
Jet/kerosene	0.19	0.18	-0.01	-4.7
Diesel	0.64	0.63	-0.01	-1.7
Fuel oil	0.17	0.23	0.06	37.3
Other products	0.20	0.22	0.02	12.1
Total	**3.08**	**3.06**	**-0.01**	**-0.4**

Note: Totals may not add up due to independent rounding. Sources: JODI, METI and OPEC.

Near-term expectations

Going forward, Japan and South Korea have largely controlled the COVID-19 pandemic, with immediate impacts on their economies and oil demand. Australia and New Zealand's zero COVID-19 policies are expected to negatively impact oil demand, at least for 4Q21. Overall demand in 2021 in the region is projected to increase y-o-y, with petrochemical feedstock being one of the main contributors to oil demand growth.

In **2022**, OECD Asia Pacific oil demand is expected to increase by 0.2 mb/d, under the assumption of an expanding GDP and COVID-19 containment. Gasoline will be the petroleum product category to increase the most, followed by industrial diesel, jet kerosene and light distillate petrochemical feedstock.

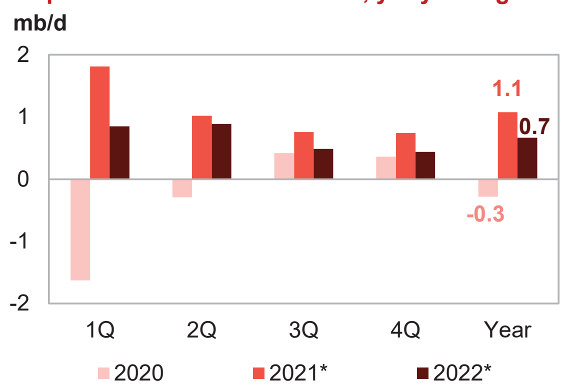
Non-OECD

China

Update on the latest developments

Chinese oil demand data for the month of **August** continued to grow, despite a localized resurgence in COIVD-19 cases and government reactions to contain the spread. August oil demand data show growth of around 0.3 mb/d following a growth of 0.2 mb/d y-o-y in July. August's total demand is also higher than pre-pandemic levels by around 0.7 mb/d compared with August 2019, amid strong petrochemical feedstock demand. Demand for LPG and naphtha was also supportive on a y-o-y basis in August, increasing by more than 0.3 mb/d y-o-y, collectively.

Graph 4 - 4: China's oil demand, y-o-y change



*Note: * 2021-2022 = Forecast. Source: OPEC.*

Naphtha demand was robust as it was the favoured petrochemical feedstock for steam crackers. LPG demand also grew y-o-y, despite increased maintenance activities for PDH plants due to weaker margins amid high propane feedstock prices and increasing maintenance plans. Fuel oil grew by around 0.3 mb/d y-o-y in August, mainly supported by an increase in bunkering activities. Gasoline was higher by 0.1 mb/d y-o-y in August compared with a 0.1 mb/d y-o-y increase in July, mainly due to restrictions related to an increase in Delta infection cases. On the other hand, jet fuel demand decreased further in August by 0.3 mb/d y-o-y in contrast to a drop of around 0.1 mb/d y-o-y in July. Daily domestic flights fell by around 40% compared with July amid an increase in the Delta variant.

Table 4 - 6: China's oil demand*, mb/d

By product	Aug 20	Aug 21	Change Aug 21/Aug 20 Growth	%
LPG	1.93	2.16	0.23	12.1
Naphtha	1.85	1.95	0.11	5.9
Gasoline	2.90	2.99	0.10	3.3
Jet/kerosene	0.82	0.50	-0.32	-38.8
Diesel	3.21	3.06	-0.15	-4.8
Fuel oil	0.47	0.75	0.28	60.5
Other products	1.66	1.68	0.02	1.2
Total	**12.83**	**13.10**	**0.27**	**2.1**

*Note: * Apparent oil demand. Totals may not add up due to independent rounding.*
Sources: Argus Global Markets, China OGP (Xnhua News Agency), Facts Global Energy, JODI, National Bureau of Statistics China and OPEC.

Near-term expectations

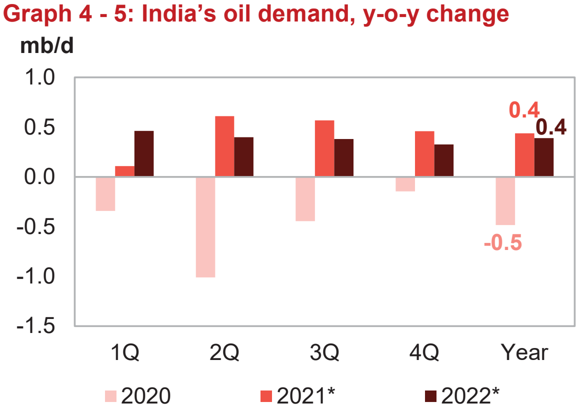
Going forward, the outbreak of COIVD-19 in some Chinese provinces might lead to localized lockdowns. However, the low tolerance policy of the government is assumed to quickly control potential spreads. On the other hand, festivities during autumn will help boost driving activity, in addition to Golden Week holidays, which will also bolster gasoline consumption. The end-of-summer fishing ban, together with the autumn harvest season, will support industrial fuel demand in the coming months. LPG and naphtha will continue to back demand growth going into the final quarter of the year, supported by seasonal demand, with naphtha gaining advantage over LPG due to price differentials. Generally, improved economic activity, together with the rigorous control of COVID-19 infection cases, leads to the assumption that oil demand will increase solidly, led by transportation and industrial fuels.

In **2022**, China's oil demand is estimated to rise y-o-y, supported by firm economic growth forecasts. The transportation and industrial sectors are anticipated to increase the most, with support coming from growth in vehicle miles driven, an increase in passenger vehicle sales and a firm industrial sector. Gasoline is likely to rise, followed by diesel. A strong petrochemical sector is anticipated to provide robust support to light distillate consumption in 2022.

India

Update on the latest developments

Graph 4 - 5: India's oil demand, y-o-y change



*Note: * 2021-2022 = Forecast. Source: OPEC.*

Indian oil demand increased by 0.4 mb/d y-o-y in **August**, rising for the third consecutive month since the resurgence of the Delta variant in May this year. Demand remained below pre-pandemic levels in India, showing a drop of around 0.3 mb/d compared with August 2019. The containment of COVID-19 infection cases led to the easing of government restriction measures across the country and improved mobility, both in road and aviation. Diesel increased the most by 0.2 mb/d y-o-y, compared with a similar rise in July. However, diesel demand was still lower than in August 2019 by 0.1 mb/d, despite the y-o-y increase. Diesel demand remained under pressure from a slower recovery in industrial activities, as well as the monsoon season. Gasoline and jet/kerosene demand increased y-o-y, affected by improving mobility and an increase in flight operations. Gasoline demand rose by around 0.1 mb/d y-o-y, while jet/kerosene added 0.03 mb/d. Gasoline requirements were trending marginally above August 2019 levels, while jet/kerosene was still 0.1 mb/d below. The mobility index, as reported by Google maps and Apple, continued to improve from 106% of pre-pandemic levels during the month of July to 116% in August. Early September indications show a further gain in mobility data in September with the easing of COVID-19 measures. Demand for the heavy end of the barrel rose by 35 tb/d versus August 2019. The heavy part of the barrel, which includes fuel oil and the other products category, was up by nearly 0.1 mb/d y-o-y in August and on par with August 2019.

Table 4 - 7: India's oil demand, mb/d

By product	Aug 20	Aug 21	Change Aug 21/Aug 20 Growth	%
LPG	0.82	0.84	0.02	2.5
Naphtha	0.21	0.20	-0.01	-7.0
Gasoline	0.65	0.74	0.09	13.1
Jet/kerosene	0.16	0.19	0.03	19.2
Diesel	1.31	1.51	0.20	14.9
Fuel oil	0.24	0.24	0.01	3.7
Other products	0.52	0.59	0.07	13.5
Total	**3.91**	**4.30**	**0.40**	**10.1**

Note: Totals may not add up due to independent rounding.

Sources: JODI, Petroleum Planning and Analysis Cell of India and OPEC.

Near-term expectations

Going forward, India's oil demand should continue to pick up pace after the monsoon season with the festive season, as well as improving industrial activity providing consumption support for the reminder of the year. However, uncertainty will remain high, largely associated with new COVID-19 variants, in addition to the pace of vaccination rollout programmes. Similarly, high retail prices and government reaction to those prices are to be closely monitored in the coming months. That said, oil demand is anticipated to pick up pace over the short term, encouraged by a low baseline and a rise in transportation and industrial fuel demand. The transportation fuel recovery is estimated to continue going forward, supported by better management of the COVID-19 pandemic. As a result, transportation fuel demand is projected to lead product demand, followed by middle distillates.

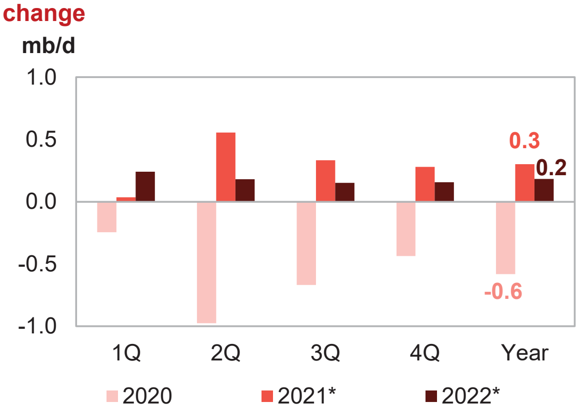
In **2022**, oil demand is anticipated to increase by around 0.4 mb/d, with total volumes expected to exceed pre-pandemic levels on an annualized basis. COVID-19 containment measures are anticipated be sustained by an increase in vaccination, natural immunization and improved management of the virus. Regarding products, gasoline is anticipated to be the strongest product in 2022, supported by an acceleration in mobility, uptick in vehicle sales and overall steady economic development. Diesel is assumed to be supported by healthy industrial, construction and agriculture activities in 2022.

Latin America

Update on the latest developments

Latin American oil demand posted steady gains for the fifth consecutive month, increasing by 0.4 mb/d y-o-y in **July**, after seeing a similar y-o-y rise in June. However, demand remained lower than in June 2019 by around 0.1 mb/d. Brazil and Argentina led those increases, rising by around 0.3 mb/d y-o-y and 0.1 mb/d y-o-y, respectively. In terms of fuel, rebounding gasoline led gains, adding nearly 0.2 mb/d y-o-y after posting 0.1 mb/d y-o-y in June. A recovery in mobility indices in the region, in addition to low consumption in July due to COVID-19, were the main supportive factors for increasing gasoline demand. Mobility in Latin America was at 102% from pre-pandemic levels, compared with 95% in June as reported by google maps and the Apple mobility index. In Brazil, mobility was at 108% in July, spurring the higher consumption of gasoline, which posted growth of more than 0.1 mb/d y-o-y.

Graph 4 - 6: Latin America's oil demand, y-o-y change



*Note: * 2021-2022 = Forecast. Source: OPEC.*

Latin American's diesel requirements also increased by more than 0.1 mb/d y-o-y in July, slightly higher than the June growth. Support stemmed from the steady development of industrial activities and stable trucking consumption, particularly in Brazil.

Table 4 - 8: Brazil's oil demand*, mb/d

By product	Aug 20	Aug 21	*Change Aug 21/Aug 20* Growth	%
LPG	0.24	0.24	0.00	-0.8
Naphtha	0.14	0.14	0.00	2.9
Gasoline	0.60	0.70	0.10	16.8
Jet/kerosene	0.04	0.08	0.04	93.2
Diesel	1.05	1.16	0.11	10.9
Fuel oil	0.07	0.12	0.05	68.5
Other products	0.44	0.39	-0.05	-12.0
Total	**2.58**	**2.83**	**0.25**	**9.7**

*Note: * = Inland deliveries. Totals may not add up due to independent rounding.*

Sources: JODI, Agencia Nacional do Petroleo, Gas Natural e Biocombustiveis and OPEC.

In **August**, oil demand increased by around 0.3 mb/d y-o-y in Brazil, after rising by similar levels in July. In contrast to August 2019, demand was slightly higher, mainly due to a steady recovery in industrial fuel demand, led by diesel. In August, transportation fuels showed strong performance as restrictive policies to control the spread of COVID-19 eased. Gasoline and jet fuel increased by more than 0.1 mb/d y-o-y collectively, after rising by similar levels in July. On-road mobility was at 112% from pre-pandemic levels in August after posting 108% in July. Diesel increased on a y-o-y basis since September 2020. Demand for diesel in August increased by more than 0.1 mb/d, after rising by similar levels in July. Industrial activity increased at the beginning of 3Q21, up by around 1.4% y-o-y, though August levels are not yet published. However, they are anticipated to show an ongoing positive trend.

Near-term expectations

Going forward, Latin American COVID-19 cases should continue to ease as vaccination accelerates. However, variants will remain to be a downside risk if lockdown measures are reinstituted. Additionally, mobility is continuing to improve, which in turn will promote transportation fuel consumption. On the other hand, recent trucker blockades in Brazil were short-lived and did not materially impact industrial fuel demand. However, government policies in response to fuel prices will have to be closely monitored. Brazil is expected to provide support to oil demand recovery for the remainder of 2021, as transportation fuel demand is projected to pick up pace. From a product point of view, diesel and transportation fuels are projected to lead oil demand growth in 4Q21.

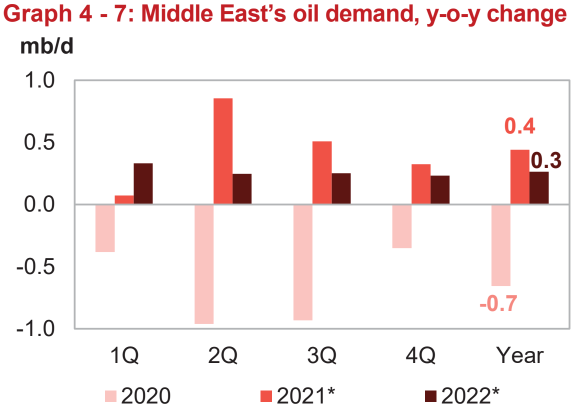
In **2022**, Latin America's oil demand is expected to remain below 2019 levels but rise y-o-y. A steady economic outlook is anticipated to support demand in the region, mostly in the region's largest-consuming counties Brazil and Argentina. Transportation fuels are anticipated to account for most of the gains in 2022, supported by COVID-19 containment measures and overall gains in economic momentum.

Middle East

Update on the latest developments

Middle Eastern oil demand increased by more than 0.5 mb/d y-o-y in **July**, after rising by 0.7 mb/d y-o-y in June. However, demand for petroleum products remained below July 2019 levels by more than 0.1 mb/d, despite higher petrochemical feedstock requirements, compared with pre-pandemic levels. A steady rise in oil requirements in Kuwait, Iraq and the UAE supported the region's demand in spite of slightly declining y-o-y demand in Saudi Arabia, the largest consuming country in the region. Looking at the product mix, gasoline and diesel demand grew the most by around 0.1 mb/d y-o-y each. Most of the gains were recorded in Kuwait and Iraq, encouraged by an uptick in mobility and low baseline in 2020.

Graph 4 - 7: Middle East's oil demand, y-o-y change



*Note: * 2021-2022 = Forecast. Source: OPEC.*

Improving economic momentum, including construction and infrastructure projects, supported industrial fuel demand. Demand for petrochemical feedstock LPG and naphtha remained ample, particularly in Kuwait due to the recent addition of naphtha cracking units. Demand for naphtha was higher in the country by around 0.1 mb/d y-o-y, showing gains compared with July 2019 of 0.1 mb/d.

Table 4 - 9: Saudi Arabia's oil demand, mb/d

			Change Aug 21/Aug 20	
By product	**Aug 20**	**Aug 21**	**Growth**	**%**
LPG	0.05	0.04	0.00	-5.1
Gasoline	0.48	0.47	-0.01	-1.8
Jet/kerosene	0.03	0.04	0.01	40.2
Diesel	0.52	0.53	0.01	2.1
Fuel oil	0.69	0.65	-0.03	-4.9
Other products	0.78	0.72	-0.06	-7.5
Total	**2.55**	**2.47**	**-0.08**	**-3.1**

Note: Totals may not add up due to independent rounding.

Sources: JODI and OPEC.

Near-term expectations

Going forward, as daily COVID-19 cases continue to decline, a return to normality is projected to continue in the coming months. Effective COVID-19 management and an acceleration in vaccination has led countries such as Saudi Arabia, the UAE, Kuwait and Qatar to gradually lift movement restrictions, supporting mobility in the coming months. Generally, oil demand is anticipated to continue its recovery process to show respectable growth. COVID-19-related risks will remain, though at a lower magnitude than previously seen. Gasoline demand is anticipated to continue to improve, while gasoil will also rise on improved industrial activity.

In **2022**, Middle East oil demand growth is anticipated increase by around 0.3 mb/d amid sustained economic growth. Regarding countries, Saudi Arabia is projected to provide the largest contribution to oil demand growth in the region, driven by steady economic expectations, controlled COVID-19 cases and a healthy petrochemical sector. Transportation fuels and light distillates are the products expected to lead oil demand in 2022.

World Oil Supply

Non-OPEC liquids supply growth in 2021 (including processing gains) was revised down by 0.3 mb/d from the previous month's assessment to 0.7 mb/d y-o-y. This is mainly due to the drop in liquids supply in August by 0.6 mb/d m-o-m, mainly in OECD Americas, due to oil production outages in the US Gulf of Mexico (GoM), a force majeure at Canada's Suncor oil sands site, and at the offshore platform in Mexico. Output disruptions also took place in other regions, including field maintenance in the Caspian. The US liquids supply forecast was once again revised down by 132 tb/d following the aftermath of Hurricane Ida and is now forecast to decline by 0.1 mb/d y-o-y. The 2021 oil supply forecast primarily sees growth in Canada, Russia, China, Brazil and Norway, while output is projected to decline in the UK, Colombia, Indonesia and Egypt.

The non-OPEC supply growth forecast for 2022 has been revised up by 0.1 mb/d, mainly in Kazakhstan, to now stand at 3.0 mb/d y-o-y. The main drivers of liquids supply growth are expected to be Russia (1.0 mb/d) and the US (0.8 mb/d), followed by Brazil, Norway, Canada, Kazakhstan, Guyana and other non-OPEC countries in the DoC. Nevertheless, uncertainty regarding the financial and operational aspects of US production remains high.

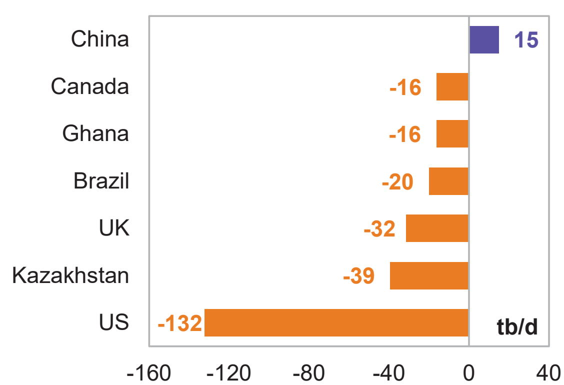
OPEC NGLs and non-conventional liquids production in 2021 are estimated to grow by 0.1 mb/d y-o-y to average 5.2 mb/d and to grow by 0.1 mb/d y-o-y in 2022, to average 5.3 mb/d. OPEC-13 crude oil production in September increased by 0.49 mb/d m-o-m to average 27.33 mb/d, according to secondary sources.

Preliminary non-OPEC liquids production in September, including OPEC NGLs, is estimated to have grown by 0.1 mb/d m-o-m to average 68.6 mb/d, up by 2.1 mb/d y-o-y. As a result, preliminary data indicates that global oil supply in September has grown by 0.61 mb/d m-o-m to average 95.93 mb/d, up by 5.39 mb/d y-o-y.

Non-OPEC liquids production growth in 2021 was revised down by 256 tb/d from the previous assessment, including 172 tb/d in the OECD and 85 tb/d in the non-OECD regions, mainly due to a total downward revision of 604 tb/d in 3Q21, as well as 317 tb/d in 4Q21. With this revision, liquids supply is now forecast to grow by 0.66 mb/d in 2021 to average 63.64 mb/d.

The main downward revision took place in OECD Americas' supply forecast by 148 tb/d (266 tb/d in 3Q21 and 303 tb/d in 4Q21), due to oil production outages in the US GoM following Hurricane Ida, and a force majeure in Canada at the Suncor oil sands site. Supply growth in the US and Canada in 2021 was revised down by 0.13 mb/d, and 0.02 mb/d, respectively. UK supply growth was also revised lower by 0.03 mb/d, due to lower-than-expected output in 3Q21 and revisions to the 4Q21 outlook.

Graph 5 - 1: Revisions to annual supply change forecast in 2021*, October MOMR/September MOMR



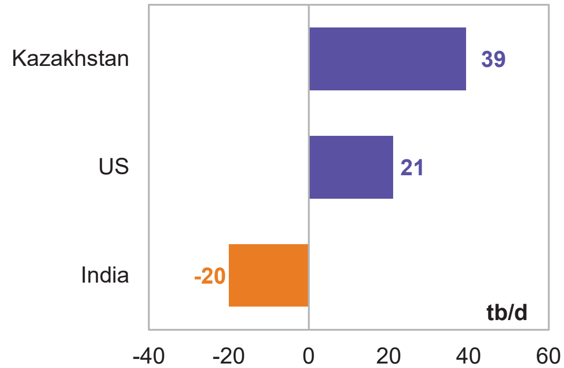
*Note: * 2021 = Forecast. Source: OPEC.*

The supply forecast of Brazil was also revised down by 0.02 mb/d due to lower-than-forecast output in 3Q21. The supply forecast of Kazakhstan, a member of the DoC, was also revised down by 0.04 mb/d. In Africa, Ghana's supply forecast was revised down by 0.02 mb/d due to downward revisions in all quarters.

The **non-OPEC supply growth forecast for 2022** has been revised up by a minor 0.07 mb/d to now stand at 3.0 mb/d. Revisions are limited to the US and Kazakhstan, as well as several minor upward revisions in other countries, due to a base change.

US supply growth was revised up by 0.02 mb/d to average 0.83 mb/d. In Kazakhstan, the supply forecast was also revised up by 0.04 mb/d, because of a base change. The oil supply forecast of India was revised down by 0.02 mb/d, and is now forecast to grow by 0.03 mb/d in 2022.

Graph 5 - 2: Revisions to annual supply change forecast in 2022*, October MOMR/September MOMR

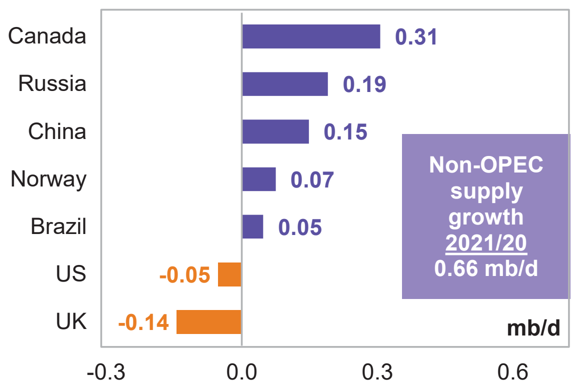


*Note: * 2022 = Forecast. Source: OPEC.*

Key drivers of growth and decline

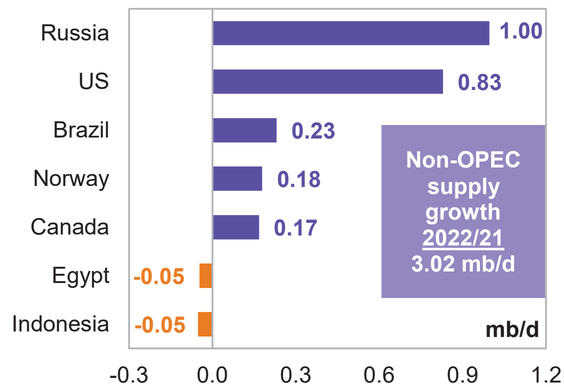
The **key drivers of non-OPEC liquids supply growth in 2021** are projected to be Canada, Russia, China, Norway, Brazil and Guyana. Oil production is expected to decline mainly in the UK, the US, Indonesia, Colombia and Egypt.

Graph 5 - 3: Annual liquids production changes for selected countries in 2021*



*Note: * 2021 = Forecast. Source: OPEC.*

Graph 5 - 4: Annual liquids production changes for selected countries in 2022*



*Note: * 2022 = Forecast. Source: OPEC.*

For **2022**, the key drivers of non-OPEC supply growth are forecast to be Russia, the US, Brazil, Norway, Canada, Kazakhstan and Guyana, while oil production is projected to decline mainly in Indonesia, Egypt and Thailand.

Non-OPEC liquids production in 2021 and 2022

Table 5 - 1: Non-OPEC liquids production in 2021*, mb/d

Non-OPEC liquids production	2020	1Q21	2Q21	3Q21	4Q21	2021	Change 2021/20 Growth	%
Americas	24.70	24.10	25.17	24.98	25.58	24.96	0.26	1.07
of which US	*17.61*	*16.63*	*17.93*	*17.63*	*18.01*	*17.55*	*-0.05*	*-0.30*
Europe	3.90	3.95	3.51	3.86	4.02	3.83	-0.07	-1.72
Asia Pacific	0.52	0.50	0.45	0.53	0.54	0.51	-0.01	-2.84
Total OECD	**29.12**	**28.55**	**29.13**	**29.36**	**30.14**	**29.30**	**0.18**	**0.62**
China	4.16	4.30	4.34	4.32	4.28	4.31	0.15	3.56
India	0.77	0.76	0.75	0.75	0.74	0.75	-0.01	-1.78
Other Asia	2.51	2.52	2.45	2.40	2.48	2.46	-0.04	-1.75
Latin America	6.04	5.97	6.00	6.12	6.47	6.14	0.10	1.60
Middle East	3.19	3.22	3.23	3.25	3.30	3.25	0.06	1.77
Africa	1.41	1.36	1.35	1.34	1.31	1.34	-0.08	-5.31
Russia	10.59	10.47	10.74	10.80	11.11	10.78	0.19	1.80
Other Eurasia	2.91	2.96	2.89	2.79	3.01	2.91	0.00	-0.05
Other Europe	0.12	0.12	0.11	0.11	0.10	0.11	-0.01	-6.16
Total Non-OECD	**31.71**	**31.66**	**31.85**	**31.89**	**32.83**	**32.06**	**0.35**	**1.10**
Total Non-OPEC production	60.83	60.21	60.99	61.25	62.96	61.36	0.53	0.87
Processing gains	2.15	2.28	2.28	2.28	2.28	2.28	0.13	6.03
Total Non-OPEC liquids production	**62.98**	**62.49**	**63.27**	**63.53**	**65.24**	**63.64**	**0.66**	**1.05**
Previous estimate	62.93	62.43	63.22	64.13	65.56	63.85	0.92	1.46
Revision	0.05	0.06	0.04	-0.60	-0.32	-0.21	-0.26	-0.41

*Note: * 2021 = Forecast. Totals may not add up due to independent rounding. Source: OPEC.*

Table 5 - 2: Non-OPEC liquids production in 2022*, mb/d

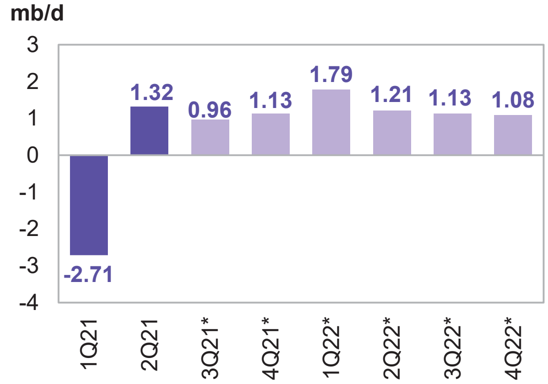
Non-OPEC liquids production	2021	1Q22	2Q22	3Q22	4Q22	2022	Change 2022/21 Growth	%
Americas	24.96	25.76	25.88	25.96	26.38	25.99	1.03	4.14
of which US	*17.55*	*18.12*	*18.45*	*18.31*	*18.65*	*18.38*	*0.83*	*4.73*
Europe	3.83	4.03	3.93	3.98	4.31	4.06	0.23	6.02
Asia Pacific	0.51	0.55	0.54	0.54	0.54	0.54	0.04	6.97
Total OECD	**29.30**	**30.33**	**30.35**	**30.49**	**31.22**	**30.60**	**1.30**	**4.44**
China	4.31	4.31	4.31	4.35	4.43	4.35	0.04	1.01
India	0.75	0.75	0.77	0.80	0.82	0.79	0.03	4.25
Other Asia	2.46	2.47	2.44	2.42	2.40	2.43	-0.03	-1.28
Latin America	6.14	6.50	6.44	6.38	6.59	6.48	0.34	5.52
Middle East	3.25	3.34	3.34	3.36	3.36	3.35	0.10	3.09
Africa	1.34	1.29	1.26	1.23	1.20	1.25	-0.09	-7.03
Russia	10.78	11.51	11.83	11.88	11.88	11.78	1.00	9.24
Other Eurasia	2.91	3.09	3.11	3.15	3.22	3.14	0.23	7.86
Other Europe	0.11	0.11	0.10	0.10	0.10	0.10	-0.01	-7.22
Total Non-OECD	**32.06**	**33.36**	**33.61**	**33.68**	**34.01**	**33.67**	**1.61**	**5.01**
Total Non-OPEC production	61.36	63.70	63.95	64.16	65.23	64.27	2.91	4.74
Processing gains	2.28	2.39	2.39	2.39	2.39	2.39	0.11	4.91
Total Non-OPEC liquids production	**63.64**	**66.09**	**66.34**	**66.56**	**67.63**	**66.66**	**3.02**	**4.74**
Previous estimate	63.85	66.22	66.48	66.69	67.76	66.79	2.95	4.61
Revision	-0.21	-0.13	-0.13	-0.13	-0.13	-0.13	0.07	0.13

*Note: * 2021-2022 = Forecast. Totals may not add up due to independent rounding. Source: OPEC.*

OECD

OECD liquids production in 2021 is forecast to increase by 0.18 mb/d y-o-y to average 29.30 mb/d, revised down by 0.17 mb/d m-o-m owing to a downward revision of 0.15 tb/d in the production forecast for OECD Americas, which is now projected to grow by 0.26 mb/d to average 24.96 mb/d. OECD Europe was revised down by 0.03 m-o-m and is now forecast to decline by 0.07 mb/d, with an average supply of 3.83 mb/d. However, oil production in OECD Asia Pacific was revised up by a minor 3 tb/d m-o-m and is now forecast to decline by 0.01 mb/d y-o-y to average 0.51 mb/d.

Graph 5 - 5: OECD quarterly liquids supply, y-o-y changes



Note: * 3Q21-4Q22 = Forecast. Source: OPEC.

For **2022**, oil production in the OECD is forecast to increase by 1.30 mb/d y-o-y to average 30.60 mb/d, revised up by 13 tb/d m-o-m, with growth in OECD Americas of 1.03 mb/d to average 25.99 mb/d. Oil production in OECD Europe and OECD Asia Pacific is anticipated to grow respectively by 0.23 mb/d and 0.04 mb/d y-o-y to average 4.06 mb/d and 0.54 mb/d.

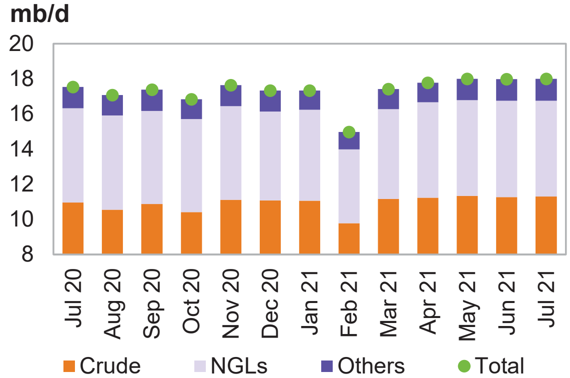
OECD Americas

US

US liquids production in July 2021 was up by 0.03 mb/d m-o-m to average 18.01 mb/d, higher by 0.46 mb/d compared with July 2020.

Crude oil production increased in July 2021 by 31 tb/d m-o-m to average 11.31 mb/d, up by 0.35 mb/d y-o-y. Meanwhile, production of non-conventional liquids (mainly ethanol) in June increased by 14 tb/d m-o-m to average 1.23 mb/d, according to the Department of Energy (DOE). It is estimated that output reached 1.25 mb/d in July. NGLs production was down by 19 tb/d to average 5.46 mb/d in July. Regarding crude and condensate production breakdown by region (PADDs), production increased on the US Gulf Coast (USGC) by 113 tb/d to average 8.11 mb/d, and a minor 3 tb/d in the Rocky Mountains to average 0.77 mb/d, while declining in the other three PADDs in July.

Graph 5 - 6: US monthly liquids output by key component



Source: OPEC.

Looking at states, production increased m-o-m in Texas, New Mexico, and the GoM (before Hurricane Ida) on the US Gulf Coast, adding 28 tb/d, 28 tb/d and 56 tb/d, to average 4.8 mb/d, 1.3 mb/d and 1.85 mb/d, respectively. Part of this monthly growth was offset by lower output in Alaska, Oklahoma and North Dakota.

In the US Midwest, production in North Dakota decreased by 9 tb/d to average 1.1 mb/d after four consecutive months of increase, while output in Oklahoma declined for the second consecutive month by 12 tb/d to average 380 tb/d in July. For the week ending 1 October, 39 oil rigs were active in Oklahoma.

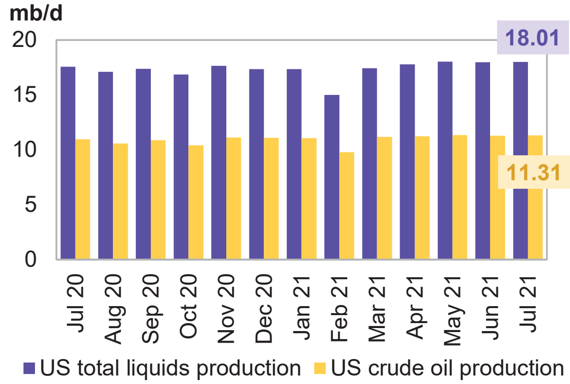
Table 5 - 3: US crude oil production by selected state and region, tb/d

State	Jun 21	Jul 21	*Change Jul 21/Jun 21*
Oklahoma	392	380	*-12*
Colorado	390	390	*0*
Alaska	440	380	*-60*
North Dakota	1,064	1,055	*-9*
New Mexico	1,267	1,295	*28*
Gulf of Mexico (GoM)	1,789	1,845	*56*
Texas	4,782	4,810	*28*
Total	**11,276**	**11,307**	***31***

Sources: EIA and OPEC.

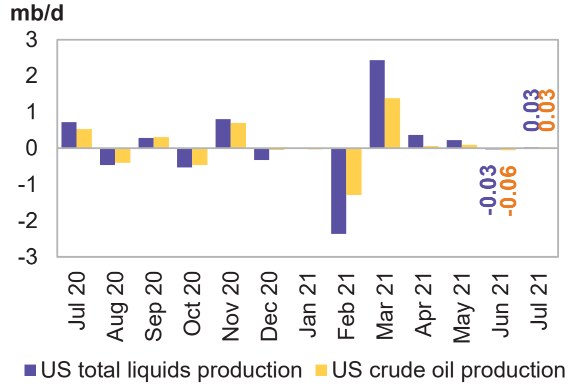
In June and July, the oil rig count increased from 28 to 30, however this increase did not offset the decline rate. Output in Colorado, the host of Niobrara shale, was flat at 0.39 mb/d. On the West Coast, production in Alaska declined for the eighth consecutive month, falling by 60 tb/d m-o-m to average 0.38 mb/d due to maintenance. Production is expected to recover in August, following the return of the 50 tb/d Alpine field. For the next year, production in Alaska will be boosted by two new projects, the Fiord West and GMT-2, with total peak capacity of 55 tb/d.

Graph 5 - 7: US monthly crude oil and total liquids supply



Sources: EIA and OPEC.

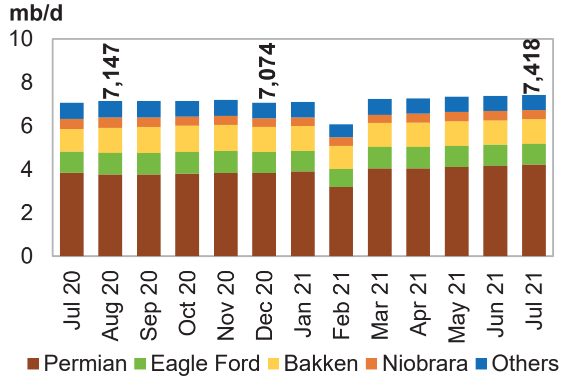
Graph 5 - 8: US monthly crude oil and total liquids supply, m-o-m changes



Sources: EIA and OPEC.

US tight crude output in July increased by 36 tb/d m-o-m to average 7.42 mb/d, 342 tb/d higher than the same month a year earlier, according to Energy Information Administration (EIA) estimates. The m-o-m increase from shale and tight formations through horizontal wells came from the Permian, rising by 57 tb/d, to average 4.22 mb/d. In the Williston Basin, production in the Bakken shale was broadly steady at an average of 1.12 mb/d, up by 85 tb/d y-o-y. Tight crude output at Eagle Ford in Texas and Niobrara-Codell in Colorado and Wyoming declined by 8 tb/d and 9 tb/d, respectively, to average 0.96 mb/d and 0.41 mb/d. In the onshore lower 48, July production increased by 35 tb/d to 9.08 mb/d. Average tight crude output in the first seven months of the year was estimated at 7.12 mb/d, 426 tb/d lower than during the same period in 2020.

Graph 5 - 9: US tight crude output breakdown

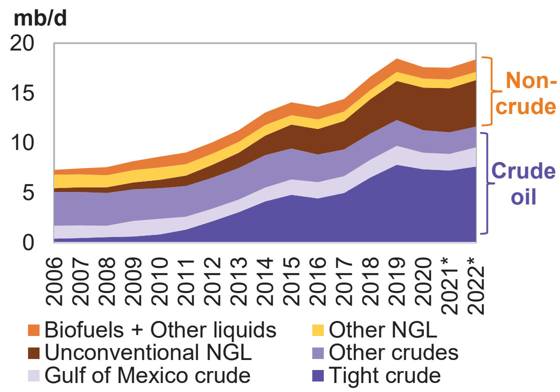


Sources: EIA, Rystad Energy and OPEC.

The **US liquids production growth forecast for 2021** was revised down by 132 tb/d and now stands to decline by 0.05 mb/d y-o-y to average 17.55 mb/d. This was due to downward revisions by 208 tb/d in 3Q21, following an oil production shut-in in the GoM due to Hurricane Ida, as well as downward revisions in the 4Q21 supply forecast by 303 tb/d.

Regarding the liquids breakdown, the **US crude production forecast for 2021** was revised down by 0.12 mb/d and is now expected to decline by 0.22 mb/d to average 11.06 mb/d. The growth forecast for NGLs and non-conventional liquids remained unchanged at 0.13 mb/d and 0.04 mb/d to average 5.31 mb/d and 1.19 mb/d, respectively.

Graph 5 - 10: US liquids supply developments by component, including forecast for 2021 and 2022



*Note: * 2021-2022 = Forecast. Source: OPEC.*

Assuming 1.57 mb/d of production in August and around 1.0 mb/d in September following Hurricane Ida-related output disruptions, average oil production from the GoM in 2021 is now forecast to stand at 1.67 mb/d with growth of only 0.02 mb/d y-o-y. US crude oil production is expected to exit December 2021 at 11.31 mb/d (as of October 2021), although production might again be affected negatively in October, as was seen in 2020. US tight and conventional crude oil are forecast to see contractions of 0.03 mb/d and 0.22 mb/d in 2021, to average 7.25 mb/d and 2.14 mb/d, respectively.

US liquids production in 2022, excluding processing gains, is anticipated to grow by 0.83 mb/d y-o-y to average 18.38 mb/d, revised up by 0.02 mb/d. With the current pace of drilling and well completion in oil fields, production of crude oil is forecast to grow by 0.6 mb/d y-o-y in 2022, revised up by 0.01 mb/d. NGLs and non-conventional liquids will continue to grow by 0.15 mb/d and 0.08 mb/d, respectively.

Regarding the **US crude oil production** forecast breakdown, production from the GoM will grow by 0.23 mb/d to average 1.90 mb/d. At the same time, the US tight crude and conventional crude oil forecast was updated to account for the latest production and activity trends, with growth of 0.41 mb/d to average 7.66 mb/d, and a contraction of 0.04 mb/d to average 2.10 mb/d, respectively.

Table 5 - 4: US liquids production breakdown, mb/d

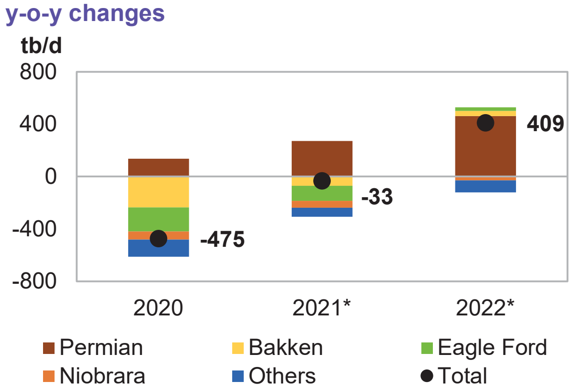
US liquids	2020	Change 2020/19	2021*	Change 2021/20	2022*	Change 2022/21
Tight crude	7.37	-0.45	7.25	-0.03	7.66	0.41
Gulf of Mexico crude	1.64	-0.25	1.67	0.02	1.90	0.23
Conventional crude oil	2.26	-0.30	2.14	-0.22	2.10	-0.04
Total crude	11.28	-1.01	11.06	-0.22	11.66	0.60
Unconventional NGLs	4.27	0.35	4.45	0.18	4.65	0.20
Conventional NGLs	0.91	0.00	0.86	-0.05	0.81	-0.05
Total NGLs	5.17	0.35	5.31	0.13	5.46	0.15
Biofuels + Other liquids	1.15	-0.20	1.19	0.04	1.27	0.08
US total supply	**17.61**	**-0.86**	**17.55**	**-0.05**	**18.38**	**0.83**

*Note: * 2021-2022 = Forecast. Sources: EIA, OPEC and Rystad Energy.*

US tight crude production in 2021 and 2022 is expected to show continuous y-o-y growth in the Permian Basin, though this has been revised down by 0.05 mb/d and 0.15 mb/d from last month's assessment to now stand at average growth of 0.2 mb/d and 0.46 mb/d, to reach 4.13 mb/d and 4.59 mb/d, respectively.

Bakken shale production fell by 0.23 mb/d in 2020 and is expected to contract by 0.07 mb/d in 2021 to average 1.11 mb/d, while for 2022, output is expected to grow by 0.04 mb/d to average 1.15 mb/d. Eagle Ford in Texas is expected to decline this year by 0.10 mb/d, but is forecast to grow next year by 0.03 mb/d to average 0.97 mb/d. Production in other shale plays is not expected to grow in 2021 or 2022, given current drilling and completion activities.

Graph 5 - 11: US tight crude output by shale play, y-o-y changes



*Note: * 2021-2022 = Forecast.*
Sources: EIA, Rystad Energy and OPEC.

US tight crude saw a contraction of 0.45 mb/d in 2020 and is expected to decline by 0.13 mb/d y-o-y this year, but is forecast to grow by 0.41 mb/d in 2022 to average 7.66 mb/d.

Table 5 - 5: US tight oil production growth, mb/d

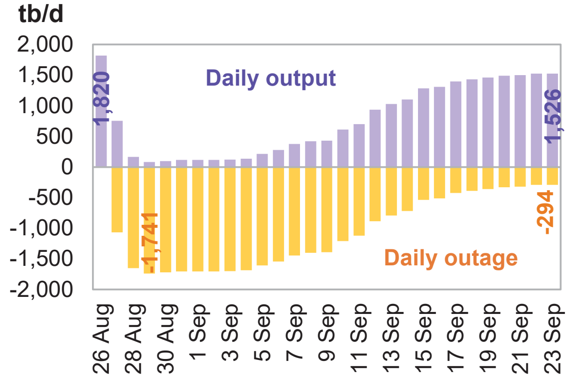
US tight oil	2020	Change 2020/19	2021*	Change 2021/20	2022*	Change 2022/21
Permian tight	3.92	0.16	4.13	0.21	4.59	0.46
Bakken shale	1.18	-0.23	1.11	-0.07	1.15	0.04
Eagle Ford shale	1.04	-0.18	0.94	-0.10	0.97	0.03
Niobrara shale	0.47	-0.06	0.40	-0.07	0.37	-0.03
Other tight plays	0.77	-0.14	0.67	-0.10	0.58	-0.09
Total	**7.37**	**-0.45**	**7.25**	**-0.13**	**7.66**	**0.41**

*Note: * 2021-2022 = Forecast. Source: OPEC.*

Hurricane Ida and its impact on US Gulf of Mexico production

According to data since 27 August on GoM oil production from the first day of evacuation and well shut-in until the final report given by the US Bureau of Safety and Environmental Enforcement (BSEE) on 23 September, more than 30 mb was cumulatively offline. From 24 September up to the end of the month, around 0.3 mb/d was still shut in. With this, it is estimated that average monthly production dropped from 1.85 mb/d in July to average 1.57 mb/d in August and around 1.0 mb/d in September. Hurricane Ida, which came ashore on 29 August, had the largest impact on US GoM supplies since Hurricane Katrina struck back in 2005.

Graph 5 - 12: Production shut in the Gulf of Mexico related to Hurricane Ida



Sources: BSEE and OPEC.

Offshore production has been gradually returning in October, including the re-starting of production at the Olympus TLP (Tension Leg Platform) following repairs to a portion of its West Delta 143 offshore facility in the aftermath of Hurricane Ida, Royal Dutch Shell announced on 4 October. However, about 175 tb/d is expected to remain offline until the end of the year from the connection side of the West Delta-143 to another two TLPs, Mars and Ursa, due to damage. Shell expects to bring these volumes back online in 1Q22. Shell's West Delta 143 offshore facility carries oil and gas from three major fields for processing at onshore terminals.

According to Shell, the largest GoM oil producer, and hardest-hit by Ida, operations at other GoM assets — Appomattox, Enchilada/Salsa, Auger, Perdido and Stones — are all producing, except for Mars and Ursa. Around 60% of Shell-operated production in the GoM is back online after the incident.

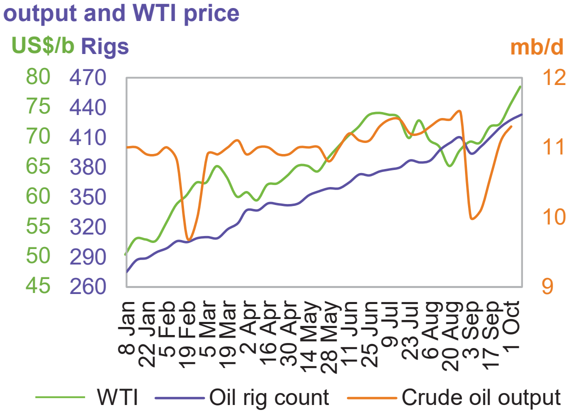
US rig count, spudded, completed, DUC wells and fracking activity

Total US **active drilling rigs** were up by 5 units w-o-w to 533 rigs in the week ended 8 October. During Hurricane Ida, the biggest weekly rig drop was seen since early June last year, according to Baker Hughes', which reported that the number of active offshore rigs had fallen to 2. US offshore rigs have currently recovered to 11 units. Moreover, 520 rigs (oil & gas) were active onshore and 2 in inland waters.

US rigs targeting crude oil rose by 5 units to 433 rigs, while gas rigs remained flat at 99 and one rig was classified as miscellaneous.

On a monthly basis, the US oil rig count increased by 16 units in September m-o-m to 415 rigs, higher by 232 rigs compared with September 2020.

Graph 5 - 13: US weekly rig count vs US crude oil output and WTI price



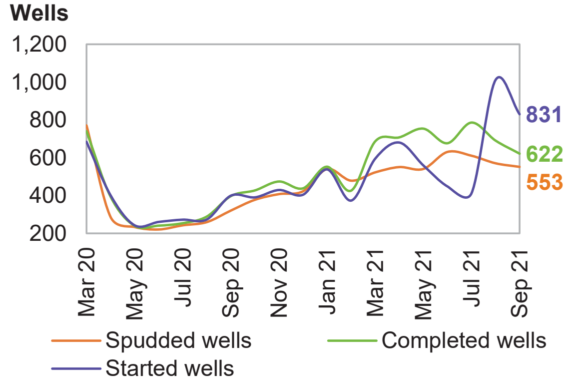
Sources: Baker Hughes, EIA and OPEC.

Rigs targeting oil in the Permian Basin almost doubled y-o-y to 266. The total rig count is 98% higher than the same time last year and up more than 118% since falling to a record low of 244 in August 2020.

Drilling and completion (D&C) activities for spudded, completed and started wells in all US shale plays saw 553 horizontal wells spudded in September (as per preliminary data), down from 572 in August, but 72% higher than in September 2020. It is worth noting that the average of spudded wells in the first eight months of year was 557, compared with September at 553 wells.

In September 2021, preliminary data indicates a lower number of completed wells at 622, as well as a lower number of started wells at 831. However, the number of completed and started wells increased respectively by 56% and 108% y-o-y.

Graph 5 - 14: Spudded, completed and started wells in US shale plays

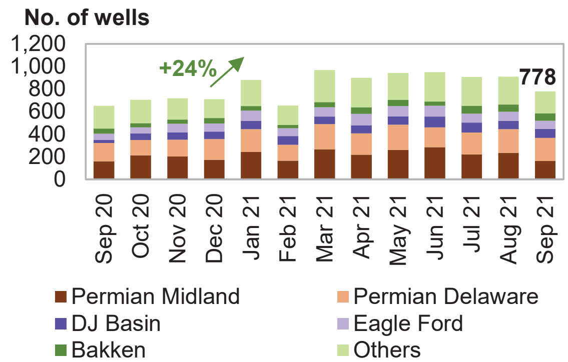


Sources: Rystad Energy and OPEC.

Regarding identified **US oil and gas fracking operations by region**, Rystad Energy reported that after 907 fracking wells were seen in July and 909 in August, 778 started fracking in September. This preliminary number is based almost exclusively on analysis of high-frequency satellite data.

Preliminary data on fracking in September shows that 163 and 203 wells were fracked in the Permian Midland Tight and Permian Delaware Tight, respectively. It also indicated that 81 wells were fracked in the DJ Basin compared with 71 in Eagle Ford and 67 in Bakken in North Dakota.

Graph 5 - 15: Fracked wells count per month



Note: September 2021 = Preliminary data.
Sources: Rystad Energy Shale Well Cube and OPEC.

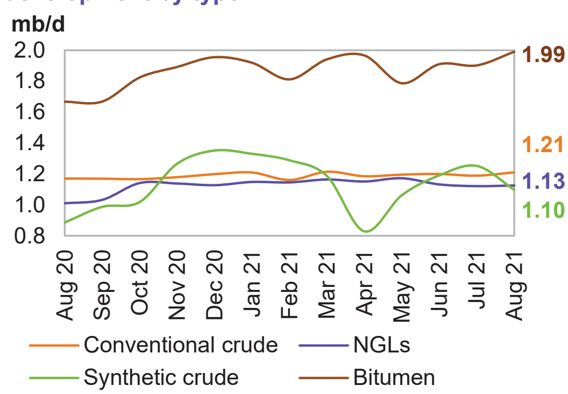
Canada

Canada's liquids production in August is estimated to have declined by 0.04 mb/d m-o-m to average 5.46 mb/d, mainly due to lower synthetic crude output.

While production of **crude bitumen** in August rose by 0.09 mb/d m-o-m to 1.99 mb/d, the highest on record and reaching October 2019 levels, **synthetic crude** declined by 154 tb/d m-o-m to average 1.1 mb/d.

Moreover, in a force majeure notice sent by one of Syncrude's four owners earlier this month, customers were informed of a supply cut by as much as 20% in September, Bloomberg reported. Regarding capacity, the Suncor synthetic upgrader in Northern Alberta produced about 275 tb/d between January and May, according to the Alberta Energy Regulator (AER).

Graph 5 - 16: Canada's monthly liquids production development by type



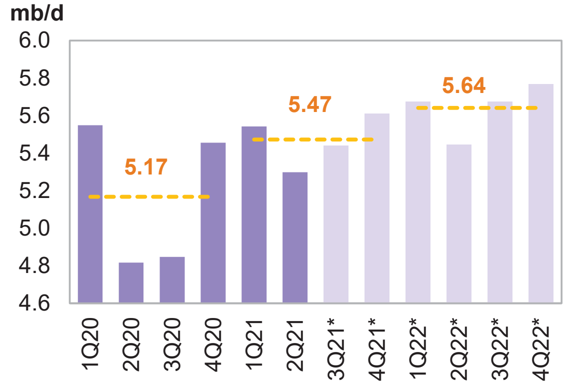
Sources: National Energy Board and OPEC.

NGLs production remained unchanged at 1.12 mb/d, but **conventional crude** output rose by 22 tb/d to average 1.21 mb/d.

With a minor downward revision of 6 tb/d in historical production data in 2Q21 and 58 tb/d in 3Q21 seen this month, the liquids supply growth forecast for the current year was revised down by 16 tb/d to stand at 0.31 mb/d, with average yearly supply at 5.47 mb/d.

For **2022**, Canada's production is forecast to increase at a slower pace compared with the current year, rising by 0.17 mb/d to average 5.64 mb/d. This is unchanged from the previous month's assessment in terms of y-o-y growth.

Graph 5 - 17: Canada's quarterly liquids production and forecast

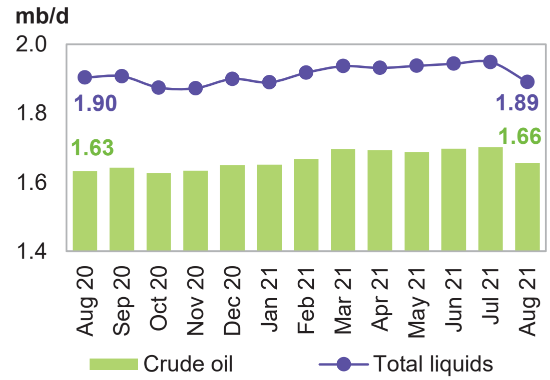


*Note: * 3Q21-4Q22 = Forecast. Source: OPEC.*

Mexico

Mexico's crude output declined **in August** by 45 tb/d to average 1.66 mb/d, following a fire on one of the Ku-Maloob-Zaap platforms located in the Mexican territories of the GoM. Mexico's Pemex exported 1.1 mb/d of crude in August, largely flat monthly and yearly, despite more than 420 tb/d of crude output being affected by the fire. The crude output breakdown indicates that the production of heavy crude oil declined from 1,031 tb/d in July to average 939 tb/d in August, partially compensated by higher extra-light crude output. According to PEMEX's updated production report, production from the KMZ had fully recovered on 30 August. Mexico's **total liquids production,** including 0.23 mb/d of NGLs, was down by 58 tb/d m-o-m in August to average 1.89 mb/d and also down by 0.01 mb/d y-o-y.

Graph 5 - 18: Mexico's monthly liquids and crude production development



Sources: PEMEX and OPEC.

For **2021**, liquids production in Mexico is forecast to grow by 0.01 mb/d to average 1.93 mb/d, unchanged from last month's assessment.

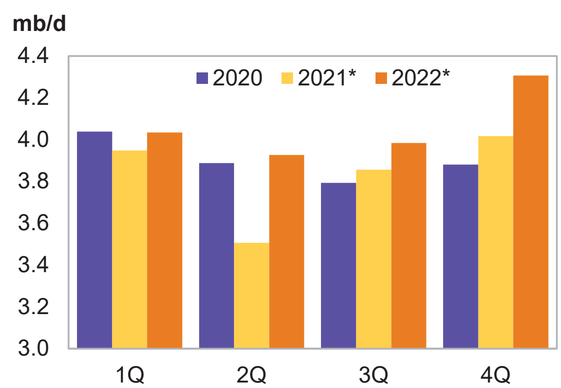
For **2022**, the supply forecast shows yearly growth of 0.04 mb/d to average 1.96 mb/d.

OECD Europe

OECD Europe's liquids production in 2021 was revised down by 0.03 mb/d from the previous assessment. The downward revision is due to lower-than-expected oil output in 3Q21 by 31 tb/d, mainly in the UK. Additionally, the 4Q21 forecast was revised down by 80 tb/d due to a re-assessment of the UK supply forecast.

OECD Europe's liquids supply is now projected to decline by 0.07 mb/d y-o-y in 2021 to average 3.83 mb/d, owing to a contraction in UK output of 0.14 mb/d and a slowdown in Norway's production growth estimated at 0.07 mb/d, compared with remarkable growth of 0.26 mb/d in 2020. Oil production in Denmark will decline by 0.01 mb/d, while oil output is expected to see minor growth of 0.01 mb/d in other OECD Europe.

Graph 5 - 19: OECD Europe quarterly liquids production and forecast



*Note: * 2021-2022 = Forecast. Source: OPEC.*

OECD Europe's oil production in 2Q21 was 3.51 mb/d, lower by 0.4 mb/d y-o-y, not only because of maintenance, natural declines and technical failure, but also due to COVID-related considerations and special controls on platforms.

For **2022**, production is expected to grow by 0.23 mb/d and surge to 4.06 mb/d through continued production ramp-ups in Norway, the UK and Other OECD Europe.

Norway

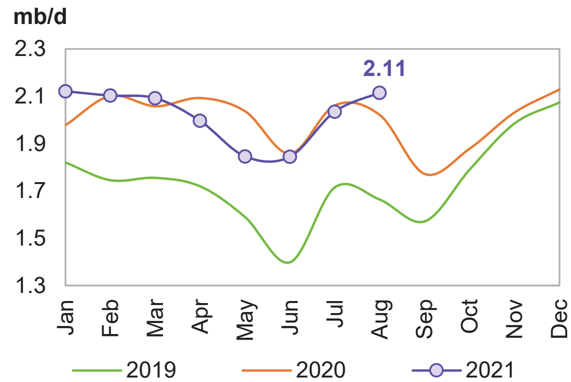
Norwegian crude production in August grew by 59 tb/d m-o-m to 1.81 mb/d, 3.0% higher than the Norwegian Petroleum Directorate's (NPD) forecast, and up by 81 tb/d y-o-y. Production of NGLs and condensates also rose by 20 tb/d m-o-m to average 0.30 mb/d.

As a result, t**otal liquids supply** increased by 0.08 mb/d m-o-m to average 2.11 mb/d, back to the same level as in 1Q21, prior to seasonal maintenance in 2Q21. However, average liquids production in the first seven months of the year stood at 2.01 mb/d, the same as in 4Q20, despite the start-up of Equinor's Martin Linge field in July, and the rebounding of production by around 0.2 mb/d over the low output seen in May and June due to seasonal maintenance, indicating no growth during this period. Nevertheless, with new projects such as Solveig, with peak capacity of 30 tboe/d, which came on stream by Lundin Energy on 30 September, and additional projects coming onstream by the end of the year, such as Duva, with a peak capacity of 30 tb/d, Yme, with 35 tb/d, and Martin Linge with 40 tb/d, Norwegian liquids output is projected to rise from 2.09 mb/d in 3Q21 to average 2.21 mb/d in 4Q21.

For **2021**, Norway's liquids supply growth forecast has been revised up by a minor 5 tb/d m-o-m due to higher-than-expected output in 3Q21 by 19 tb/d. Production is now expected to average 2.08 mb/d, with growth of 0.07 mb/d y-o-y.

For **2022**, Norway's tax incentives initiated last year in response to the pandemic have led to increased investment in oil and gas projects. Consequently, Norwegian liquids production is expected to grow by 0.18 mb/d to average 2.26 mb/d through the anticipated start-up of new offshore projects such as Nova, Hod (redevelopment), Njord Future, Bauge and Fenja-phase 1. Moreover, Johan Sverdrup phase-2 is expected to come on-stream in late 2022, and is projected to lift Norwegian crude oil production to more than 2 mb/d.

Graph 5 - 20: Norway's monthly liquids production development



Sources: NPD and OPEC.

UK

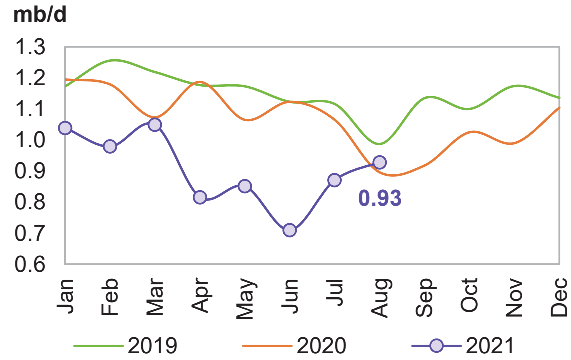
UK liquids production in August was up by 0.06 mb/d m-o-m to average 0.93 mb/d, higher by 0.14 mb/d than the average output in 2Q21, and up by 0.03 mb/d y-o-y. The lowest-ever production recorded this year in 2Q21 of 0.79 mb/d was due to extensive maintenance on the Forties Pipeline System (FPS), planned workovers, and full production shut-in at the UK's largest producing field, Buzzard. Crude oil output rose by 41 tb/d m-o-m to average 0.8 mb/d, according to official data, up by 0.02 mb/d y-o-y. NGLs output also increased by 16 tb/d m-o-m in August to average 84 tb/d, up by a minor 4 tb/d y-o-y.

Historical production data in 2Q21 has been revised up by a minor 5 tb/d, but the supply forecast for 3Q21, and 4Q21 has been revised down by 50 tb/d and 80 tb/d, respectively, leading to a downward revision of 32 tb/d for the 2021 UK supply forecast, compared to the previous assessment.

For **2021**, UK liquids production is forecast to contract by 0.14 mb/d to average 0.92 mb/d.

For **2022**, UK liquids production is forecast to grow by 0.03 mb/d to average 0.96 mb/d, following two consecutive years of heavy declines. Production ramp-ups will take place in some small fields. The Penguins oil field (Redevelop) and Buzzard Phase 2 (20/06-3), each with a peak capacity of 30 tb/d, are due to start up. However, several new UK projects that are in the pipeline could be delayed. Argus reported that "BP has delayed an FID on the third development phase of the Claire field, Claire South, until 2022 as it considers the impact of the pandemic and energy transition on its upstream portfolio".

Graph 5 - 21: UK monthly liquids production development



Sources: Department of Energy & Climate Change and OPEC.

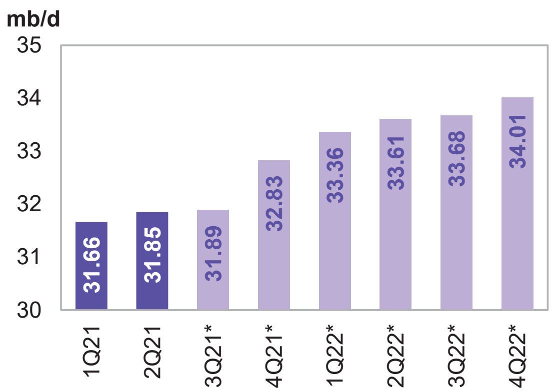
The UK's future oil and gas activities in the North Sea face serious challenges and uncertainty, which may force the government to change its decision to continue allowing E&P activities in the region.

Non-OECD

Non-OECD liquids production growth for 2021 was revised down by 85 tb/d this month on the back of downward adjustments for the Other Asia region (-15 tb/d), Latin America (-29 tb/d), Africa (-24 tb/d) and Other Eurasia, mainly Kazakhstan (-41 tb/d), and is now forecast to grow by 0.35 mb/d to average 32.06 mb/d.

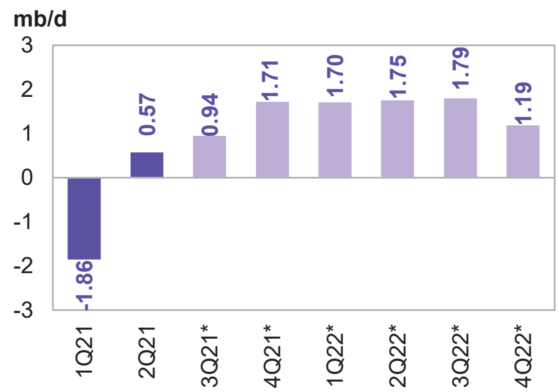
The liquids supply forecast of the 10 non-OPEC countries participating in the DoC was revised down by 0.04 mb/d to average 17.4 mb/d, now standing at growth of 0.2 mb/d y-o-y.

Graph 5 - 22: Non-OECD quarterly liquids production and forecast



*Note: * 3Q21-4Q22 = Forecast. Source: OPEC.*

Graph 5 - 23: Non-OECD quarterly liquids supply, y-o-y changes



*Note: * 3Q21-4Q22 = Forecast. Source: OPEC.*

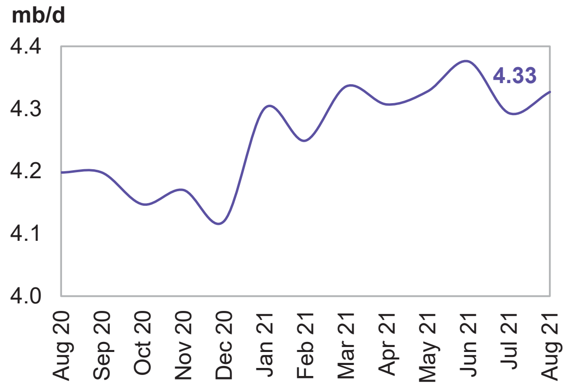
The key driver for growth in 2021 will be Russia, with y-o-y growth forecast at 0.19 mb/d, followed by China, which is expected to see growth of 0.15 mb/d, Latin America with 0.10 mb/d and the Middle East with 0.06 mb/d. Liquids supply in India, Other Asia, Africa, and Other Europe will decline by 0.01 mb/d, 0.04 mb/d, 0.08 mb/d and 0.01 mb/d, respectively, while supply in Other Eurasia is forecast to remain flat y-o-y.

For **2022**, liquids production in non-OECD countries is forecast to grow by 1.61 mb/d to average 33.67 mb/d, revised up by 59 tb/d, coming mainly from Kazakhstan's forecast, due to a low base. The key drivers will again be Russia, with growth of 1.0 mb/d, followed by Latin America with 0.34 mb/d, Other Eurasia at 0.23 mb/d and the Middle East at 0.10 mb/d. China and India are expected to grow by 0.04 mb/d and 0.03 mb/d, respectively. Liquids supply is forecast to decline in Other Asia, Africa, and Other Europe.

China

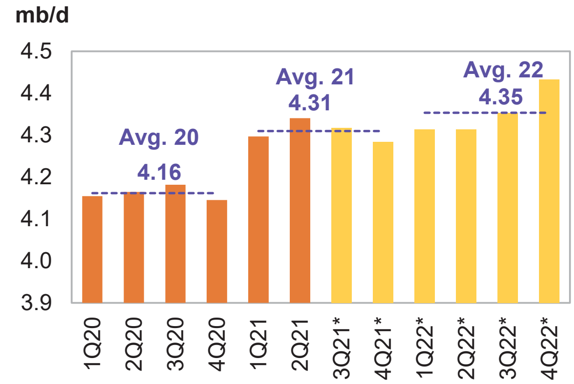
China's liquids production in August was up by 0.04 mb/d m-o-m to average 4.33 mb/d and higher by 0.13 mb/d y-o-y, according to official data. Crude oil output in August increased by 37 tb/d to average 4.01 mb/d and was higher by around 89 tb/d y-o-y. Production from the Bozhong 19-4 oilfield comprehensive adjustment project in the southern Bohai Sea offshore China was started under CNOOC on 24 September. It is anticipated that peak oil production will be around 11 tb/d in the next year.

Graph 5 - 24: China's monthly liquids production development



Sources: CNPC and OPEC.

Graph 5 - 25: China's quarterly liquids production and forecast



*Note: * 3Q21-4Q22 = Forecast. Sources: CNPC and OPEC.*

For **2021**, China's liquids supply is projected to see growth of 0.15 mb/d, revised up by 0.02 mb/d. It is worth noting that China's historical liquids production in 2020 was revised up by 0.04 mb/d to average 4.16 mb/d, with y-o-y growth of 0.11 mb/d. Moreover, supply for all quarters in 2021 was revised up, leading to an upward revision of 15 tb/d for the year. According to a list of new projects, three (namely Liuhua 16-2, Luda 21-2 and Caofeidian 6-4, all offshore) are expected to start production in 2021.

For **2022**, y-o-y growth of 0.04 mb/d is anticipated to average 4.35 m/d. For the next year, two other offshore CNNOC projects – Wushi 17-2, with peak capacity of 24 tb/d and Lufeng 14-4/14-8, with 23 tb/d at peak capacity – are planned to come onstream.

Latin America

Brazil

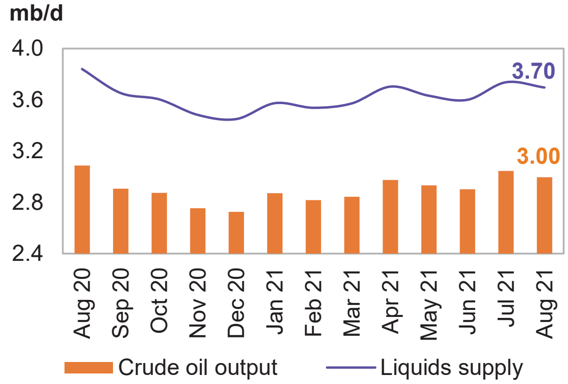
Brazil's crude output in August declined once again by 0.05 mb/d to average 3.0 mb/d, despite a production start-up at the Sepia field in the Santos Basin at the Carioca FPSO with a production capacity of 0.18 mb/d. Longer-than-expected unplanned maintenance, however, led to lower output from other fields in the Santos Basin, such as the Buzios, Lula, Tupi and Lara. Many of these disruptions were due to COVID-related mandates and health regulations observed on platforms. Production at Buzios via four FPSOs — P-74, P-75, P-76 and P-77 — is operated by Petrobras and production rates are among the highest in the pre-salt province. The tender for the P-80 FPSO — a unit which will have the capacity to produce 225 tb/d of oil and 12 mcm/d of natural gas — has been pushed back to 2022.

In **August**, **total liquids production** was pegged at 3.70 mb/d, including biofuels and NGLs, down by 0.04 mb/d m-o-m and lower by 0.14 mb/d y-o-y.

Brazilian **liquids supply in 2021**, including biofuels, is forecast to grow by 0.05 mb/d y-o-y to an average of 3.72 mb/d, revised down by 0.02 mb/d.

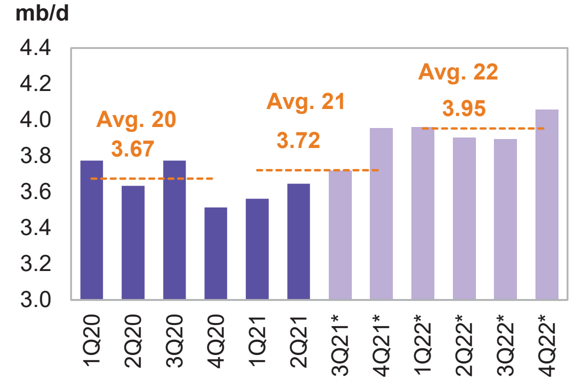
For **2022**, Brazil's liquids supply forecast, including biofuels, is set to increase by 0.23 mb/d y-o-y to average 3.95 mb/d. Crude oil production is expected to rise through two new project start-ups: Mero-1 (Guanabara), which was initially planned to start up in 2021 and Peregrino-Phase 2. Moreover, in Buzios, a fifth unit, the Almirante Barroso FPSO — to be supplied by Japan's Modec — is due to begin operation in 2022.

Graph 5 - 26: Brazil's monthly liquids production development by type



Sources: ANP, Petrobras and OPEC.

Graph 5 - 27: Brazil's quarterly liquids production and forecast



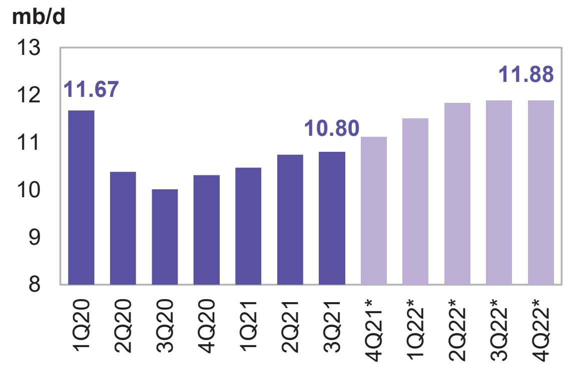
*Note: * 3Q21-4Q22 = Forecast. Sources: ANP and OPEC.*

Russia

Preliminary data for **Russia's liquids production in September** shows an increase of 0.29 mb/d m-o-m to average 10.98 mb/d, higher by 0.84 mb/d y-o-y. Regarding crude output in August, growth of 0.10 mb/d to average 9.72 mb/d was reported by Nefte Compass.

The production of **condensate and NGLs** from gas condensate fields was disrupted by 0.16 mb/d in August, due to fire. It is believed to have recovered to average 1.13 mb/d, the same as in July, according to a preliminary estimate.

Graph 5 - 28: Russia's quarterly liquids production and forecast



*Note: * 4Q21-4Q22 = Forecast.*
Sources: Nefte Compass and OPEC.

Annual liquids production in 2021 is forecast to increase by 0.19 mb/d y-o-y to average 10.78 mb/d, unchanged m-o-m. Gazprom is taking steps to increase the production capacity of its depleted Urengoi field in West Siberia, which should allow it to respond more swiftly to winter demand fluctuations, according to Argus.

For **2022**, Russian liquids output is expected to increase by 1.0 mb/d to average 11.78 mb/d, with 3Q22 and 4Q22 both expected to reach 11.88 mb/d, the same as in the last MOMR. However, insufficient drilling and brownfield declines may yet impact the forecast.

Caspian

Kazakhstan & Azerbaijan

In **Kazakhstan**, maintenance in the Tengiz field led to a cumulative production shut-in of 11.6 mb **in August and September**. Kazakh crude output declined by 0.22 mb/d m-o-m in August, as per preliminary data.

NGLs output in August is estimated to have declined by 31 tb/d to average 309 tb/d.

The Kazakhstan liquids supply forecast for **2021** is expected to decline by 0.01 mb/d and average 1.81 mb/d, revised down by 0.04 mb/d, due to production outages in August and September owing to maintenance in the Tengiz field.

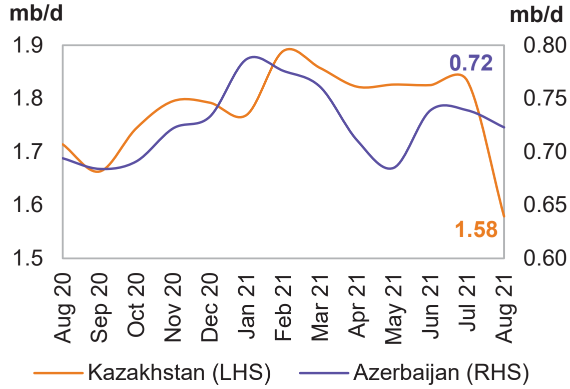
In **2022**, liquids supply is likely to grow by 0.17 mb/d to average 1.98 mb/d. CPC data shows lower export volumes in August than reported by other sources by 0.21 mb/d.

Azerbaijan's liquids production in August declined by 0.02 mb/d to average 0.72 mb/d m-o-m, up by 0.03 mb/d y-o-y. While crude production declined by 11 tb/d m-o-m to average 596 tb/d, NGLs production also declined by a minor 5 tb/d to average 127 tb/d. A 25-day maintenance programme at the Chirag platform began on 23 September. Chirag field production fell by 21% in the first half of the year to 30 tb/d compared with the previous year, with overall ACG output of Azeri Light crude 6% lower at 468 tb/d in January–June, according to BP.

In **2021**, Azerbaijan's liquids supply is expected to show growth of 0.02 mb/d y-o-y to average 0.75 mb/d.

In **2022,** the liquids supply is forecast to grow by 0.07 mb/d y-o-y to average 0.82 mb/d.

Graph 5 - 29: Caspian monthly liquids production development by selected country



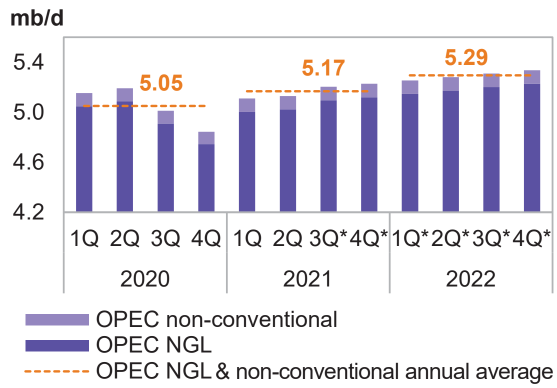
Sources: Nefte Compass and OPEC.

OPEC NGLs and non-conventional oils

OPEC NGLs and non-conventional liquids in 2021 are estimated to grow by 0.12 mb/d, following a decline of 0.17 mb/d in 2020, to average 5.17 mb/d, revised down from last month's assessment by 24 tb/d.

The preliminary **2022** forecast indicates growth of 0.13 mb/d to average 5.29 mb/d. NGLs production is expected to grow by 0.13 mb/d to average 5.19 mb/d, while non-conventional liquids is projected to remain unchanged at 0.11 mb/d.

Graph 5 - 30: OPEC NGLs and non-conventional liquids quarterly production and forecast



*Note: * 3Q21-4Q22 = Forecast. Source: OPEC.*

Table 5 - 6: OPEC NGL + non-conventional oils, mb/d

OPEC NGL and non-coventional oils	2020	Change 20/19	2021	Change 21/20	1Q22	2Q22	3Q22	4Q22	2022	Change 22/21
OPEC NGL	**4.94**	*-0.18*	**5.06**	*0.11*	5.15	5.17	5.20	5.23	**5.19**	*0.13*
OPEC non-conventional	**0.10**	*0.01*	**0.11**	*0.00*	0.11	0.11	0.11	0.11	**0.11**	*0.00*
Total	**5.05**	***-0.17***	**5.17**	***0.12***	**5.25**	**5.28**	**5.31**	**5.33**	**5.29**	***0.13***

Note: 2021-2022 = Forecast. Source: OPEC.

OPEC crude oil production

According to secondary sources, total **OPEC-13 crude oil production** averaged 27.33 mb/d in September 2021, higher by 0.49 mb/d m-o-m. Crude oil output increased mainly in Nigeria, Saudi Arabia and Iraq.

Table 5 - 7: OPEC crude oil production based on *secondary sources*, tb/d

Secondary sources	2019	2020	1Q21	2Q21	3Q21	Jul 21	Aug 21	Sep 21	*Change* Sep/Aug
Algeria	1,022	897	870	886	921	911	920	932	*12*
Angola	1,401	1,255	1,141	1,111	1,105	1,067	1,116	1,133	*17*
Congo	324	288	271	262	256	258	252	259	*6*
Equatorial Guinea	117	115	107	109	100	100	101	100	*-1*
Gabon	208	195	185	186	187	179	180	202	*22*
IR Iran	2,356	1,988	2,214	2,443	2,493	2,493	2,482	2,503	*22*
Iraq	4,678	4,049	3,881	3,940	4,052	3,965	4,056	4,139	*84*
Kuwait	2,687	2,432	2,328	2,356	2,445	2,424	2,442	2,468	*26*
Libya	1,097	367	1,175	1,151	1,153	1,158	1,153	1,148	*-5*
Nigeria	1,786	1,579	1,413	1,423	1,376	1,385	1,296	1,451	*156*
Saudi Arabia	9,794	9,182	8,445	8,503	9,544	9,420	9,539	9,678	*139*
UAE	3,094	2,802	2,610	2,644	2,761	2,722	2,774	2,789	*14*
Venezuela	796	500	517	511	528	526	533	527	*-6*
Total OPEC	**29,361**	**25,650**	**25,156**	**25,526**	**26,922**	**26,609**	**26,842**	**27,328**	***486***

Notes: Totals may not add up due to independent rounding, given available secondary sources to date. Source: OPEC.

Table 5 - 8: OPEC crude oil production based on *direct communication*, tb/d

Direct communication	2019	2020	1Q21	2Q21	3Q21	Jul 21	Aug 21	Sep 21	*Change* Sep/Aug
Algeria	1,023	899	874	886	924	915	921	937	*16*
Angola	1,373	1,271	1,136	1,125	1,114	1,103	1,129	1,110	*-19*
Congo	329	300	276	265	265	248	270	277	*8*
Equatorial Guinea	110	114	104	99	97	100	101	91	*-10*
Gabon	218	207	183	179	180	185	179	175	*-4*
IR Iran	..	..	..	..	..	..	..	..	..
Iraq	4,576	3,997	3,846	3,890	3,979	3,886	3,961	4,093	*132*
Kuwait	2,678	2,438	2,327	2,355	2,447	2,423	2,445	2,474	*29*
Libya	..	389	1,214	1,213	1,220	1,273	1,223	1,161	*-62*
Nigeria	1,737	1,493	1,404	1,343	1,270	1,323	1,239	1,247	*8*
Saudi Arabia	9,808	9,213	8,473	8,535	9,565	9,474	9,562	9,662	*100*
UAE	3,058	2,779	2,610	2,645	2,758	2,722	2,768	2,786	*18*
Venezuela	1,013	569	533	556	635	614	641	650	*9*
Total OPEC	**..**	**..**	**..**	**..**	**..**	**..**	**..**	**..**	**..**

Notes: .. Not available. Totals may not add up due to independent rounding. Source: OPEC.

Commercial Stock Movements

Preliminary August data sees total OECD commercial oil stocks down by 19.5 mb m-o-m. At 2,855 mb, they were 363 mb lower than the same time one year ago, 183 mb lower than the latest five-year average and 131 mb below the 2015-2019 average. Within the components, crude stocks fell m-o-m by 22.8 mb, while product stocks were up by 3.2 mb.

At 1,362 mb, crude stocks in the OECD were 102 mb less than the latest five-year average and 87 mb below the 2015-2019 average. OECD product stocks stood at 1,493 mb, representing a deficit of 81 mb compared with the latest five-year average and 43 mb below the 2015-2019 average.

In terms of days of forward cover, OECD commercial stocks fell m-o-m by 0.1 days in August to stand at 62.5 days. This is 12.3 days below August 2020 levels, 2.5 days less than the latest five-year average and 0.3 days lower than the 2015-2019 average.

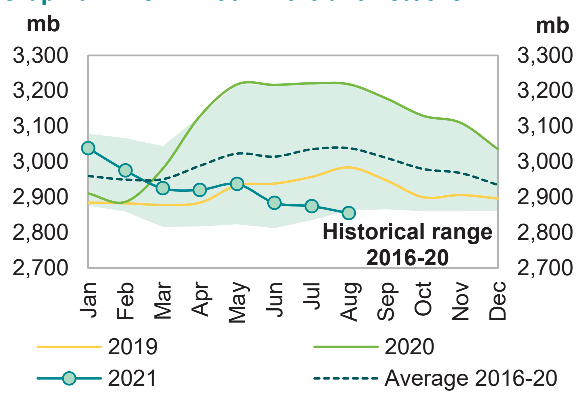
Preliminary data for September showed that total US commercial oil stocks fell m-o-m by 10.0 mb to stand at 1,234 mb. This is 189.4 mb, or 13.3%, lower than the same month a year ago and 95.6 mb, or 7.2%, below the latest five-year average. Crude and products stocks fell m-o-m by 4.5 mb and 5.5 mb, respectively.

OECD

Preliminary August data sees **total OECD commercial oil stocks** down by 19.5 mb m-o-m. At 2,855 mb, they were 363 mb lower than the same time one year ago and 183 mb lower than the latest five-year average.

Within the components, crude stocks fell m-o-m by 22.8 mb, while product stocks were up by 3.2 mb. Total commercial oil stocks in August fell in OECD America and OECD Europe, while they rose in OECD Asia Pacific.

Graph 9 - 1: OECD commercial oil stocks



Sources: Argus, EIA, Euroilstock, IEA, METI and OPEC.

OECD **commercial crude stocks** fell m-o-m in August by 22.8 mb to stand at 1,362 mb. This is 171.5 mb lower than the same time a year ago and 87.3 mb below the latest five-year average. Compared with the previous month, OECD Americas and OECD Europe registered stock draws of 13.5 mb and 10.8 mb, respectively, while OECD Asia Pacific saw a stock build of 1.5 mb.

In contrast, **total product inventories** rose m-o-m by 3.2 mb in August to stand at 1,493 mb. This is 191.7 mb less than the same time a year ago, and 80.9 mb lower than the latest five-year average. Within the OECD, product stocks in OECD Asia Pacific and OECD Europe rose m-o-m by 4.8 mb and 3.0 mb, respectively, while OECD America fell by 4.5 mb.

Table 9 - 1: OECD's commercial stocks, mb

OECD stocks	Aug 20	Jun 21	Jul 21	Aug 21	*Change* Aug 21/Jul 21
Crude oil	1,534	1,393	1,385	1,362	*-22.8*
Products	1,685	1,491	1,490	1,493	*3.2*
Total	**3,218**	**2,884**	**2,875**	**2,855**	***-19.5***
Days of forward cover	**74.8**	**62.7**	**62.6**	**62.5**	***-0.1***

Note: Totals may not add up due to independent rounding.

Sources: Argus, EIA, Euroilstock, IEA, METI and OPEC.

In terms of **days of forward cover**, OECD commercial stocks fell m-o-m by 0.1 days in August to stand at 62.5 days. This is 12.3 days below August 2020 levels, 2.5 days less than the latest five-year average and 0.3 days lower than the 2015-2019 average. OECD Americas and OECD Asia Pacific were below the latest five-year average: the Americas by 2.7 days at 61.5 days and Asia Pacific by 5.1 days at 49.9 days. OECD Europe also showed a deficit of 1.3 days with the latest five-year average, at 70.8 days.

OECD Americas

OECD Americas total commercial stocks fell m-o-m by 18.1 mb in August to settle at 1,528 mb. This is 174.6 mb less than the same month last year and 68.8 mb lower than the latest five-year average.

Commercial crude oil stocks in OECD Americas fell m-o-m by 13.5 mb in August to stand at 768 mb, which is 78.4 mb lower than in August 2020 and 22.5 mb less than the latest five-year average. The stock draw came on the back of higher crude runs in August.

Total product stocks in OECD Americas fell m-o-m by 4.5 mb in August to stand at 761 mb. This was 96.1 mb lower than the same month one year ago and 46.3 mb below the latest five-year average. Lower total consumption in the region was behind the stock build.

OECD Europe

OECD Europe total commercial stocks fell m-o-m by 7.8 mb in August to settle at 977 mb. This is 115.1 mb less than the same month last year and 38.6 mb below the latest five-year average.

OECD Europe's **commercial crude stocks** in August fell m-o-m by 10.8 mb to end the month at 417 mb, which is 37.8 mb lower than one year ago and 18.5 mb below the latest five-year average. The fall in crude oil inventories came on the back of higher m-o-m refinery throughputs in the EU-14 plus the UK and Norway, which increased by around 350 tb/d to 9.76 mb/d in August.

In contrast, OECD Europe's **commercial product stocks** rose m-o-m by 3.0 mb to end August at 560 mb. This is 77.3 mb lower than a year ago and 20.2 mb below the latest five-year average.

OECD Asia Pacific

OECD Asia Pacific's total commercial oil stocks rose m-o-m by 6.4 mb in August to stand at 349 mb. This is 73.6 mb lower than a year ago and 75.8 mb below the latest five-year average.

OECD Asia Pacific's **crude inventories** rose by 1.5 mb m-o-m to end August at 177 mb, which is 55.3 mb lower than one year ago and 61.4 mb below the latest five-year average.

OECD Asia Pacific's **total product inventories** increased by 4.8 mb m-o-m to end August at 172 mb. This is 18.3 mb lower than the same time a year ago and 14.4 mb less than the latest five-year average.

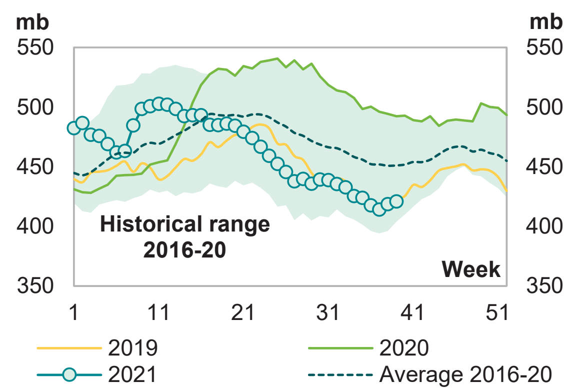
US

Preliminary data for September showed that **total US commercial oil stocks** fell m-o-m by 10.0 mb to stand at 1,234 mb. This is 189.4 mb, or 13.3%, lower than the same month a year ago and 95.6 mb, or 7.2%, below the latest five-year average. Crude and product stocks fell m-o-m by 4.5 mb and 5.5 mb, respectively.

US **commercial crude stocks** in September fell m-o-m by 4.5 mb to stand at 420.9 mb. This is 76.8 mb, or 15.4%, lower than the same month last year, and 35.3 mb, or 7.7%, below the latest five-year average. The stock draw came despite lower crude runs, which declined by around 1.0 mb/d to an average of 15.6 mb/d.

Total product stocks in September fell m-o-m by 5.5 mb to stand at 812.9 mb. This is 112.6 mb, or 12.2%, below September 2020 levels, and 60.3 mb, or 6.9%, lower than the latest five-year average. The stock draw was mainly driven by higher US consumption.

Graph 9 - 2: US weekly commercial crude oil inventories



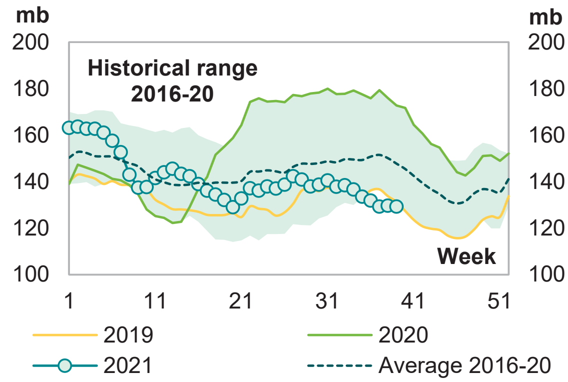
Sources: EIA and OPEC.

Gasoline stocks in September fell m-o-m by 2.1 mb to settle at 225.1 mb. This is 2.5 mb, or 1.1%, below the same month last year, and 5.0 mb, or 2.2%, lower than the latest five-year average. The monthly stock draw came mainly on the back of higher gasoline consumption.

Distillate stocks dropped m-o-m by 7.4 mb in September to stand at 129.3 mb. This is 43.2 mb, or 25.0%, lower than the same month last year, and 18.7 mb, or 12.6%, below the latest five-year average.

Jet fuel fell m-o-m by 1.1 mb, ending September at 41.3 mb. This is 1.2 mb, or 2.9%, higher than the same month last year, and 2.7 mb, or 6.1%, above the latest five-year average.

Graph 9 - 3: US weekly distillate inventories



Sources: EIA and OPEC.

Residual fuel oil stocks dropped m-o-m in September, falling by 0.6 mb. At 28.2 mb, this was 3.9 mb, or 12.3%, lower than a year ago, and 4.5 mb, or 13.8%, below the latest five-year average.

Table 9 - 2: US commercial petroleum stocks, mb

US stocks	Sep 20	Jul 21	Aug 21	Sep 21	*Change* Sep 21/Aug 21
Crude oil	**497.7**	**438.9**	**425.4**	**420.9**	***-4.5***
Gasoline	227.6	230.8	227.2	225.1	*-2.1*
Distillate fuel	172.5	142.0	136.7	129.3	*-7.4*
Residual fuel oil	32.1	29.1	28.7	28.2	*-0.6*
Jet fuel	40.1	43.8	42.4	41.3	*-1.1*
Total products	**925.5**	**830.0**	**818.4**	**812.9**	***-5.5***
Total	**1,423.2**	**1,268.9**	**1,243.8**	**1,233.8**	***-10.0***
SPR	**642.2**	**621.3**	**621.3**	**617.8**	***-3.5***

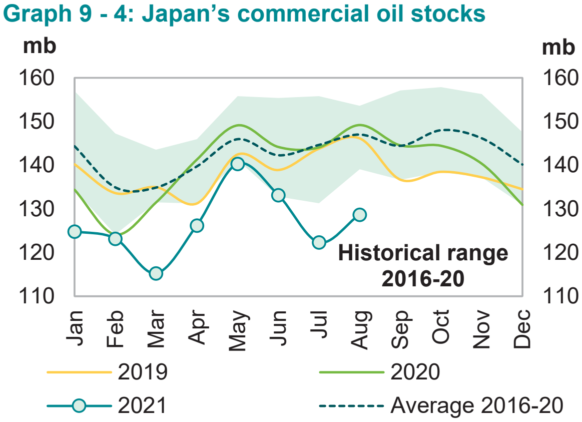
Sources: EIA and OPEC.

Japan

In **Japan**, **total commercial oil stocks** in August rose m-o-m by 6.4 mb to settle at 128.7 mb. This is 20.5 mb, or 13.7%, lower than the same month last year, and 18.3 mb, or 12.5%, below the latest five-year average. Crude and products stocks rose m-o-m by 1.5 mb and 4.8 mb, respectively.

Japanese **commercial crude oil stocks** rose in August to stand at 67.1 mb. This is 16.9 mb, or 20.1%, below the same month a year ago, and 15.1 mb, or 18.4%, lower than the latest five-year average. The build came on the back of higher crude imports, which increased by 11.4%.

Graph 9 - 4: Japan's commercial oil stocks



Sources: METI and OPEC.

Japan's **total product inventories** rose m-o-m by 4.8 mb to end August at 61.6 mb. This is 3.6 mb, or 5.5%, lower than the same month last year, and 3.2 mb, or 5.0%, below the latest five-year average.

Gasoline stocks rose m-o-m by 0.1 mb to stand at 10.0 mb. This was 2.1 mb, or 17.6%, lower than a year ago, and 0.6 mb, or 5.4%, below the latest five-year average. Higher gasoline production, which rose by 6.4%, was behind the build in gasoline stocks.

Distillate stocks rose m-o-m by 3.3 mb to end August at 29.8 mb. This is 2.5 mb, or 7.9%, lower than the same month a year ago, and 1.5 mb, or 4.7%, below the latest five-year average. Within distillate components, **jet fuel, kerosene and gasoil stocks** rose m-o-m by 21.7%, 10.2% and 11.2%, respectively. This stock build was driven by higher production.

Total residual fuel oil stocks rose m-o-m by 0.6 mb to end August at 12.4 mb. This is 0.1 mb, or 0.5%, higher than the same month last year, and 0.7 mb, or 5.3%, below the latest five-year average. Within the components, fuel oil A and fuel oil B.C stocks rose by 6.6% and 3.6%, respectively.

Table 9 - 3: Japan's commercial oil stocks*, mb

Japan's stocks	Aug 20	Jun 21	Jul 21	Aug 21	*Change* Aug 21/Jul 21
Crude oil	**84.0**	**70.6**	**65.5**	**67.1**	***1.5***
Gasoline	12.2	14.4	10.0	10.0	*0.1*
Naphtha	8.3	9.3	8.5	9.4	*0.9*
Middle distillates	32.4	27.1	26.5	29.8	*3.3*
Residual fuel oil	12.3	11.8	11.8	12.4	*0.6*
Total products	**65.2**	**62.6**	**56.8**	**61.6**	***4.8***
Total**	**149.2**	**133.2**	**122.3**	**128.7**	***6.4***

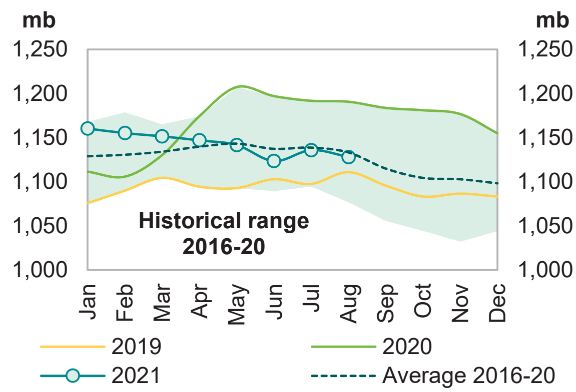
*Note: * At the end of the month. ** Includes crude oil and main products only.*
Sources: METI and OPEC.

EU-14 plus UK and Norway

Preliminary data for August showed that **total European commercial oil stocks** fell m-o-m by 7.8 mb to stand at 1,128 mb. At this level, they were 62.6 mb, or 5.3%, below the same month a year ago, and 5.3 mb, or 0.5%, lower than the latest five-year average. Crude stocks dropped m-o-m by 10.8 mb, while product stocks witnessed a build of 3.0 mb.

European **crude inventories** fell in August to stand at 465.7 mb. This is 25.7 mb, or 5.2%, lower than the same month a year ago and 19.3 mb, or 4.0%, lower than the latest five-year average. The fall in crude oil inventories came on the back of higher m-o-m refinery throughputs in the EU-14 plus the UK and Norway, which increased by around 350 tb/d to 9.76 mb/d in August.

Graph 9 - 5: EU-14 plus UK and Norway's total oil stocks



Sources: Argus, Euroilstock and OPEC.

In contrast**, total European product stocks** rose m-o-m by 3.0 mb to end August at 662.4 mb. This is 36.9 mb, or 5.3%, lower than the same month a year ago, but 14.0 mb, or 2.2%, above the latest five-year average.

Gasoline stocks rose m-o-m by 2.6 mb in August to stand at 116.2 mb. At this level, they are in line with the same time a year ago, but 5.6 mb/d, or 5.0%, above the latest five-year average.

Distillate stocks increased m-o-m by 0.6 mb in August to stand at 450.2 mb. This is 31.7 mb, or 6.6%, below the same month last year, but 6.8 mb, or 1.5%, above the latest five-year average.

Naphtha stocks rose by 0.2 mb m-o-m in August, ending the month at 31.3 mb. This is 0.9 mb, or 2.8%, above August 2020 levels, and 4.8 mb, or 18.1%, higher than the latest five-year average.

In contrast, **residual fuel stocks** fell m-o-m by 0.4 mb in August to 64.7 mb. This is 6.1 mb, or 8.6%, lower than the same month one year ago, and 3.1 mb, or 4.6%, below the latest five-year average.

Table 9 - 4: EU-14 plus UK and Norway's total oil stocks, mb

EU stocks	Aug 20	Jun 21	Jul 21	Aug 21	*Change* Aug 21/Jul 21
Crude oil	**491.4**	**464.1**	**476.5**	**465.7**	***-10.8***
Gasoline	116.2	113.6	113.6	116.2	*2.6*
Naphtha	30.5	30.1	31.2	31.3	*0.2*
Middle distillates	481.8	448.8	449.6	450.2	*0.6*
Fuel oils	70.8	66.8	65.1	64.7	*-0.4*
Total products	**699.2**	**659.2**	**659.4**	**662.4**	***3.0***
Total	**1,190.6**	**1,123.4**	**1,135.9**	**1,128.0**	***-7.8***

Sources: Argus, Euroilstock and OPEC.

Singapore, Amsterdam-Rotterdam-Antwerp (ARA) and Fujairah

Singapore

In August, **total product stocks in Singapore** fell m-o-m by 1.9 mb to 45.4 mb. This is 6.5 mb, or 12.6%, lower than the same month a year ago.

Light distillate stocks dropped m-o-m by 0.5 mb in August to stand at 13.2 mb. This is 0.7 mb, or 5.1%, lower than the same month one year ago.

Residual fuel oil stocks fell m-o-m by 1.9 mb, ending August at 20.8 mb, which is 1.7 mb, or 7.4%, lower than in August 2020.

In contrast, **middle distillate stocks** rose m-o-m by 0.5 mb in August to stand at 11.4 mb. This is 4.1 mb, or 26.7%, lower than a year ago.

ARA

Total product stocks in ARA fell for the sixth consecutive month in August and were down by 1.6 mb m-o-m at 39.6 mb. This is 9.3 mb, or 19.0%, lower than the same month a year ago.

Gasoline stocks in August fell m-o-m by 0.9 mb to stand at 5.7 mb, which is 6.2 mb, or 52.2%, lower than the same month one year ago.

Gasoil stocks dropped m-o-m by 0.2 mb in August to stand at 15.4 mb, which is 3.8 mb, or 19.9%, lower than in August 2020.

Jet oil stocks fell m-o-m by 1.0 mb to end August at 8.0 mb. This is 0.9 mb, or 12.8%, higher than the level registered one year ago.

In contrast**, residual fuel oil stocks** rose m-o-m by 0.5 mb to end August at 7.7 mb. This is 0.8 mb, or 10.9%, lower than the level seen one year ago.

Fujairah

During the week ending 4 October 2021, **total oil product stocks in Fujairah** rose w-o-w by 1.18 mb to stand at 16.71 mb, according to data from Fed Com and S&P Global Platts. At this level, total oil stocks were 3.99 mb lower than the same time a year ago. While light distillates witnessed a stock draw w-o-w, middle and heavy distillate stocks showed a stock build.

Light distillate stocks fell by 0.43 mb w-o-w to stand at 4.68 mb in the week to 4 October 2021, which is 1.60 mb lower than the same period a year ago. In contrast, **middle distillate stocks** rose by 0.16 mb to stand at 3.86 mb, which is 0.01 mb lower than a year ago. **Heavy distillate stocks** increased by 1.45 mb to stand at 8.18 mb, which is 2.38 mb lower than the same time last year.

Balance of Supply and Demand

Demand for OPEC crude in 2021 was revised up by 0.1 mb/d from the previous MOMR to stand at 27.8 mb/d, around 5.0 mb/d higher than in 2020.

According to secondary sources, OPEC crude production averaged 25.2 mb/d in 1Q21, almost the same level as demand for OPEC crude in the same period. In 2Q21, OPEC crude production averaged 25.5 mb/d, 1.4 mb/d lower than demand for OPEC crude. In 3Q21, OPEC crude oil production averaged 26.9 mb/d, 2.7 mb/d lower than demand for OPEC crude.

Demand for OPEC crude in 2022 was also revised up by 0.1 mb/d from the previous month to stand at 28.8 mb/d, around 1.0 mb/d higher than in 2021.

Balance of supply and demand in 2021

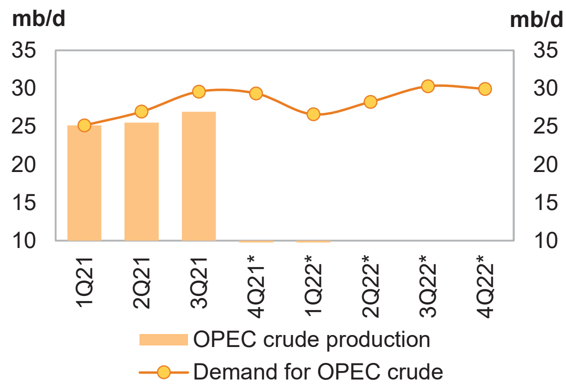
Demand for OPEC crude in 2021 was revised up by 0.1 mb/d from the previous MOMR to stand at 27.8 mb/d, around 5.0 mb/d higher than in 2020.

Compared with the previous assessment, 1Q21 and 2Q21 were revised down by 0.1 mb/d and 0.3 mb/d, respectively, while 3Q21 and 4Q21 were revised up by 0.5 mb/d and 0.4 mb/d, respectively.

When compared with the same quarters in 2020, demand for OPEC crude in 1Q21 and 2Q21 is estimated to be higher by 3.6 mb/d and 9.7 mb/d, respectively. In 3Q21 and 4Q21, there is an expected rise of 4.6 mb/d and 2.3 mb/d, respectively.

According to secondary sources, OPEC crude production averaged 25.2 mb/d in 1Q21, almost the same level as demand for OPEC crude in the same period. In 2Q21, OPEC crude production averaged 25.5 mb/d, 1.4 mb/d lower than demand for OPEC crude. In 3Q21, OPEC crude oil production averaged 26.9 mb/d, 2.7 mb/d lower than demand for OPEC crude.

Graph 10 - 1: Balance of supply and demand, 2021–2022*



*Note: * 4Q21-4Q22 = Forecast. Source: OPEC.*

Table 10 - 1: Supply/demand balance for 2021*, mb/d

	2020	1Q21	2Q21	3Q21	4Q21	2021	*Change 2021/20*
(a) World oil demand	**90.79**	**92.77**	**95.36**	**98.33**	**99.82**	**96.60**	***5.82***
Non-OPEC liquids production	62.98	62.49	63.27	63.53	65.24	63.64	*0.66*
OPEC NGL and non-conventionals	5.05	5.11	5.13	5.20	5.23	5.17	*0.12*
(b) Total non-OPEC liquids production and OPEC NGLs	**68.03**	**67.60**	**68.40**	**68.73**	**70.47**	**68.81**	***0.78***
Difference (a-b)	**22.76**	**25.17**	**26.96**	**29.60**	**29.36**	**27.80**	***5.04***
OPEC crude oil production	**25.65**	**25.16**	**25.53**	**26.92**			
Balance	**2.89**	**-0.01**	**-1.44**	**-2.68**			

*Note: * 2021 = Forecast. Totals may not add up due to independent rounding. Source: OPEC.*

Balance of supply and demand in 2022

Demand for OPEC crude in 2022 was also revised up by 0.1 mb/d from the previous month to stand at 28.8 mb/d, around 1.0 mb/d higher than in 2021.

Compared with the previous assessment, 1Q22 and 4Q22 were revised up by 0.1 mb/d and 0.3 mb/d, respectively, while 2Q22 was revised down by 0.1 mb/d. The 3Q22 was unchanged.

Compared with the same quarters in 2021, demand for OPEC crude in 1Q22 and 2Q22 is forecast to be higher by 1.4 mb/d and 1.3 mb/d, respectively. Meanwhile, 3Q22 and 4Q22 are projected to show an increase of 0.7 mb/d and 0.6 mb/d, respectively.

Table 10 - 2: Supply/demand balance for 2022*, mb/d

	2021	1Q22	2Q22	3Q22	4Q22	2022	*Change 2022/21*
(a) World oil demand	**96.60**	**97.95**	**99.88**	**102.16**	**102.93**	**100.76**	***4.15***
Non-OPEC liquids production	63.64	66.09	66.34	66.56	67.63	66.66	*3.02*
OPEC NGL and non-conventionals	5.17	5.25	5.28	5.31	5.33	5.29	*0.13*
(b) Total non-OPEC liquids production and OPEC NGLs	**68.81**	**71.34**	**71.63**	**71.86**	**72.96**	**71.95**	***3.15***
Difference (a-b)	**27.80**	**26.61**	**28.26**	**30.30**	**29.97**	**28.80**	***1.01***

*Note: * 2021-2022 = Forecast. Totals may not add up due to independent rounding. Source: OPEC.*

https://www.iea.org/reports/oil-market-report-october-2021

Oil Market Report - October 2021

Flagship report — October 2021

About this report

The IEA Oil Market Report (OMR) is one of the world's most authoritative and timely sources of data, forecasts and analysis on the global oil market – including detailed statistics and commentary on oil supply, demand, inventories, prices and refining activity, as well as oil trade for IEA and selected non-IEA countries.

Highlights

- The ongoing energy crisis has prompted a switch to oil that could boost demand by 500 kb/d compared with normal conditions. This contributed to an upward revision to our 2021 and 2022 forecast, by 170 kb/d and 210 kb/d respectively. Global oil demand is now forecast to rise by 5.5 mb/d in 2021 and 3.3 mb/d in 2022 when it reaches 99.6 mb/d, slightly above pre-Covid levels.
- World oil supply has resumed its uptrend as OPEC+ continues to unwind cuts, the US bounces back from Hurricane Ida and maintenance winds down. From September through end-2021, global output is set to rise 2.7 mb/d with OPEC+ accounting for 1.5 mb/d and non-OPEC+ pumping the rest. Total oil output fell 260 kb/d in September to 96 mb/d, led by steeper US hurricane losses.
- Global refinery activity in 3Q21 continued to disappoint, with lower throughputs in China and India in August only partially offset by a stronger performance in OECD Asia and Europe. Implied 3Q21 refined product balances show the largest draw in eight years, which explains the strong increase in refinery margins in September despite significantly higher crude prices.
- OECD total industry stocks drew by 28 mb in August to 2 824 mb, 162 mb below pre-Covid five-year average. Preliminary September data for the US, Europe and Japan show on-land industry stocks fell by a further 23 mb. Crude oil held in floating storage decreased by 8.5 mb to 98 mb in August.
- Crude oil prices hit a seven-year high in early October boosted by energy supply concerns and continued oil stock draws. North Sea Dated prices rose by $3.65/bbl on average in September to $74.40/bbl and WTI at Cushing $3.84/bbl to $71.56/bbl. Strong backwardation restrained crude price differentials to marker crudes over the month.

Bumpy road ahead

Oil prices are scaling multi-year highs as a shortage of natural gas, LNG and coal boosts demand for oil, which could keep the market in deficit through at least the end of the year. Brent crude futures rose by more than $10/bbl to surpass $83/bbl, while WTI traded above $80/bbl at the time of writing.

The surge in prices has swept through the entire global energy chain, fuelled by robust economic growth as the world emerges from the pandemic. Record coal and gas prices as well as rolling black-outs are prompting the power sector and energy-intensive industries to turn to oil to keep the lights on and operations humming. The higher energy prices are also adding to inflationary pressures that, along with power outages, could lead to lower industrial activity and a slowdown in the economic recovery.

For now, a reduction in the number of new Covid cases and rising mobility are lending support to oil demand. Global gasoline demand is currently running 2% below pre-Covid levels compared with a deficit of more than 10% at the start of the year. Air-travel is lagging further behind. All in all, world oil demand is forecast to rise by 5.5 mb/d, to 96.3 mb/d in 2021 and 3.3 mb/d in 2022, when it is set to reach pre-Covid levels.

World oil supply, meanwhile, is projected to rise sharply in October as US output bounces back from Hurricane Ida and OPEC+ continues to unwind cuts. Earlier this month the producer group reconfirmed its agreement to boost output by 400 kb/d for November, despite calls from major consuming countries for a more substantial increase to stall the decline in global oil inventories and the rise in prices. Preliminary data shows OECD industry stocks fell 23 mb in September to stand 210 mb below their five-year average and at their lowest level since March 2015.

With OPEC+ currently on track to pump 700 kb/d below the call for its crude during 4Q21, inventories will continue to decline. As the bloc ramps up production, its spare capacity will dwindle. Compared with a cushion of 9 mb/d in 1Q21, effective spare capacity could fall below 4 mb/d by 2Q22 and be concentrated in only a few Middle Eastern countries, although supply is expected to exceed demand. Shrinking global spare capacity underscores the need for increased investments to meet demand further down the road.

As the IEA's World Energy Outlook 2021 published this week highlights, the world is not investing enough to meet its future energy needs. Transition-related spending is gradually picking up, but remains far short of what is required to meet the rising demand for energy services in a sustainable way. At the same time, the amount being spent on oil appears to be geared towards a world of stagnant or falling demand. A surge in spending on clean energy transitions provides the way forward, but this needs to happen quickly or global energy markets will face a bumpy road ahead.

Bloomberg reporting on IEA OMR

IEA World Oil Supply and Demand Forecasts: Summary (Table)
2021-10-14 08:00:00.2 GMT

By Kristian Siedenburg
(Bloomberg) -- Following is a summary of world oil supply and demand forecasts from the International Energy Agency in Paris:

	4Q 2022	3Q 2022	2Q 2022	1Q 2022	4Q 2021	3Q 2021	2Q 2021	1Q 2021	2022	2021
					Demand					
Total Demand	100.2	100.5	99.1	98.6	98.9	97.8	95.2	93.4	99.6	96.3
Total OECD	46.3	46.7	45.7	45.4	45.9	45.7	44.0	42.3	46.0	44.5
Americas	25.1	25.5	25.1	24.3	24.8	24.9	24.3	22.7	25.0	24.2
Europe	13.3	13.8	13.5	13.2	13.3	13.7	12.6	11.9	13.5	12.9
Asia Oceania	7.8	7.4	7.2	7.9	7.8	7.1	7.0	7.7	7.6	7.4
Non-OECD countries	53.9	53.9	53.4	53.1	53.0	52.1	51.2	51.1	53.6	51.8
FSU	5.1	5.0	4.7	4.8	4.9	4.9	4.7	4.6	4.9	4.8
Europe	0.8	0.8	0.8	0.7	0.8	0.8	0.7	0.7	0.8	0.8
China	15.5	15.7	15.7	15.3	15.2	15.3	15.2	14.6	15.6	15.1
Other Asia	14.3	13.6	14.1	14.4	14.1	12.7	13.0	13.6	14.1	13.3
Americas	6.2	6.2	6.1	6.0	6.1	6.2	5.9	5.8	6.1	6.0
Middle East	8.0	8.5	7.9	7.8	7.9	8.4	7.8	7.7	8.1	7.9
Africa	4.1	4.0	4.1	4.1	4.0	3.9	3.9	4.1	4.1	4.0
					Supply					
Total Supply	n/a	n/a	n/a	n/a	n/a	96.3	94.2	92.4	n/a	n/a
Non-OPEC	67.2	67.2	66.5	65.4	65.0	64.1	63.4	61.9	66.6	63.6
Total OECD	29.9	29.5	29.2	29.0	28.8	28.0	27.8	27.4	29.4	28.0
Americas	25.8	25.6	25.2	24.9	24.7	24.2	24.2	23.3	25.4	24.1
Europe	3.5	3.4	3.4	3.6	3.6	3.4	3.1	3.6	3.5	3.4
Asia Oceania	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
Non-OECD	31.9	31.9	31.8	31.5	31.0	30.5	30.5	30.2	31.8	30.6
FSU	14.8	14.8	14.7	14.5	14.1	13.7	13.7	13.4	14.7	13.7
Europe	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
China	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1
Other Asia	2.7	2.8	2.8	2.8	2.8	2.8	2.9	3.0	2.8	2.9
Americas	5.7	5.6	5.5	5.5	5.4	5.4	5.3	5.3	5.6	5.3
Middle East	3.3	3.3	3.3	3.3	3.2	3.1	3.1	3.1	3.3	3.1
Africa	1.2	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3
Processing Gains	2.4	2.4	2.4	2.4	2.3	2.3	2.2	2.1	2.4	2.3
Total OPEC	n/a	n/a	n/a	n/a	n/a	32.2	30.8	30.5	n/a	n/a
Crude	n/a	n/a	n/a	n/a	n/a	26.9	25.5	25.3	n/a	n/a
Natural gas liquids NGLs	5.5	5.5	5.5	5.5	5.3	5.3	5.3	5.2	5.5	5.3
Call on OPEC crude and stock change *	27.5	27.8	27.1	27.7	28.5	28.3	26.5	26.3	27.5	27.4

NOTE: Figures are in million of barrels per day. (*) equals total demand minus non-OPEC supply and OPEC natural gas liquids.
IEA changed the way it measures OPEC supply, adopting the industry-standard approach of counting most of Venezuela's Orinoco heavy oil as "crude oil."
SOURCE: International Energy Agency

To contact the reporter on this story: Kristian Siedenburg in Vienna at ksiedenburg@bloomberg.net
To contact the editors responsible for this story: Joshua Robinson at jrobinson37@bloomberg.net
Mark Evans

To view this story in Bloomberg click here: https://blinks.bloomberg.com/news/stories/R0YECKGFLIIO

IEA: September Crude Oil Production in OPEC Countries (Table)
2021-10-14 08:00:00.1 GMT

By Kristian Siedenburg
(Bloomberg) -- Following is a summary of oil production in OPEC countries from the International Energy Agency in Paris:

	Sept. 2021	Aug. 2021	Sept. MoM
Total OPEC	27.15	26.81	0.34
Total OPEC10	22.97	22.67	0.30
Algeria	0.94	0.92	0.02
Angola	1.11	1.13	-0.02
Congo	0.25	0.26	-0.01
Equatorial Guinea	0.10	0.10	0.00
Gabon	0.20	0.18	0.02
Iraq	4.15	4.07	0.08
Kuwait	2.47	2.44	0.03
Nigeria	1.27	1.24	0.03
Saudi Arabia	9.68	9.56	0.12
UAE	2.80	2.77	0.03
Iran	2.46	2.42	0.04
Libya	1.15	1.15	0.00
Venezuela	0.57	0.57	0.00

NOTE: Figures are in million of barrels per day. Monthly level change calculated by Bloomberg.
OPEC10 excludes Iran, Libya and Venezuela.
SOURCE: International Energy Agency

To contact the reporter on this story: Kristian Siedenburg in Vienna at ksiedenburg@bloomberg.net
To contact the editors responsible for this story: Joshua Robinson at jrobinson37@bloomberg.net
Mark Evans

To view this story in Bloomberg click here:
https://blinks.bloomberg.com/news/stories/R0YECKGF4NPC

IEA REPORT WRAP: Oil Demand Forecasts Elevated as Supply Rises
2021-10-14 08:18:40.613 GMT

By Stephen Voss
(Bloomberg) -- Summary including stories from IEA's monthly
Oil Market Report on Thursday:
* IEA says shortages of natural gas in Europe and Asia are
boosting demand for oil, deepening what was already a sizable
supply deficit in crude markets
** "Massive switch" away from gas is boosting oil demand
** Unseasonably high demand for oil products seen in some places
* World oil supply seen rising sharply this month
** U.S. bouncing back from hurricane, OPEC+ unwinds cuts
** Global oil supply to reach pre-Covid levels in 1H 2022
* World demand forecasts raised on gas-to-oil switching

** 2021, 2022 forecasts raised by 170k b/d, 210k b/d
** Biggest upward revisions are for 3Q21 and 1Q22
* Click here for summary of key IEA supply/demand forecasts
* OPEC Output Rose 340k B/D Last Month on Saudi, Iraqi Gains: IEA
** See full table
* OPEC+ alliance crude supply +500k b/d m/m in September to 42.16m b/d
** Included gains from Russia, Kazakhstan
* Compliance with pledged target cutbacks in September:
** OPEC 118%; non-OPEC 113%; combined OPEC+ 116%
** Saudi Arabia 102%, Russia 92%
* Big Oil Producers to Return to Pre-Covid Output in 2022: IEA
* Energy Crunch to Add 500k b/d to Oil Demand Through 1Q, IEA Says
* European Oil Demand Set to Drop by 410K B/D Q/Q by Year-End: IEA
* Oil Product Stockpiles to Extend Biggest Drop in 8 Years: IEA
* Non-OPEC Supply to Rise by 1.2M B/d in 4Q on U.S., Canada: IEA
* Natural Gas Crunch Pushes Up Hydrogen Costs for Refiners: IEA
* NOTE: OPEC issued its own monthly report on Wednesday, sounding a cautious note on the strength of oil demand
* NOTE: The 23-nation OPEC+ alliance led by Saudi Arabia and Russia are continuing with their plan to revive the rest of the production they halted during the pandemic in careful installments, of 400k b/d each month

--With assistance from Amanda Jordan, Julian Lee and Rachel Graham.

To contact the reporter on this story:
Stephen Voss in London at sev@bloomberg.net
To contact the editors responsible for this story:
Will Kennedy at wkennedy3@bloomberg.net
Stephen Voss, John Deane

To view this story in Bloomberg click here:
https://blinks.bloomberg.com/news/stories/R0YFXLDWLU6W

IEA World Oil Supply/Demand Key Forecasts
2021-10-14 08:00:00.4 GMT

By Kristian Siedenburg
(Bloomberg) -- World oil demand 2022 fcast was revised to 99.6m b/d from 99.4m b/d in Paris-based Intl Energy Agency's latest monthly report.
* 2021 world demand was revised to 96.3 from 96.1m b/d

* Demand change in 2022 est. 3.4% y/y or 3.3m b/d
* Non-OPEC supply 2022 was revised to 66.6m b/d from 66.7m b/d
* Call on OPEC crude 2022 was revised to 27.5m b/d from 27.2m b/d
* Call on OPEC crude 2021 was revised to 27.4 m b/d from 27.2m b/d
** OPEC crude production in Sept. rose by 340k b/d on the month to 27.15m b/d
* Detailed table: FIFW NSN R0YECKGFLIIO <GO>
* NOTE: Fcasts based off IEA's table providing one decimal point

To contact the reporter on this story:
Kristian Siedenburg in Vienna at ksiedenburg@bloomberg.net
To contact the editors responsible for this story:
Joshua Robinson at jrobinson37@bloomberg.net
Mark Evans

To view this story in Bloomberg click here:
https://blinks.bloomberg.com/news/stories/R0YEDYGETF5S

OPEC Output Rose 340k B/D Last Month on Saudi, Iraqi Gains: IEA
2021-10-14 08:00:00.11 GMT

By Amanda Jordan
(Bloomberg) -- OPEC pumped 27.15m b/d of crude in September, up 340k b/d from a month earlier, with Saudi Arabia and Iraq leading the gains, the International Energy Agency said in its monthly report.
* Saudi Arabia produced 9.68m b/d, up 120k b/d m/m, just below its September quota
* Output from Iraq rose 80k b/d to 4.15m b/d, slightly above its quota
* Elsewhere in the Gulf, Kuwait's production gained 30k b/d to 2.47m b/d; in the UAE output climbed by a similar amount to reach 2.8m b/d
* Volumes from Iran, exempt from curbs, inched up 40k b/d to 2.46m b/d
* In Africa, Nigeria boosted production by 30k b/d to 1.27m b/d, while Angolan output slid 20k b/d to 1.11m b/d -- 240k b/d lower than its quota -- due to maintenance
* Libya, exempt from cuts, kept output steady at 1.15m b/d
* Venezuelan supply unchanged at 570k b/d
* NOTE: At OPEC+'s meeting in early October, ministers reconfirmed a 400k b/d increase for November despite calls from major consuming countries to boost supply faster. They'll convene again on Nov. 4
* READ, Oct. 13: OPEC Remains Cautious on Oil-Demand Strength

Despite Price Surge

To contact the reporter on this story:
Amanda Jordan in London at ajordan11@bloomberg.net
To contact the editors responsible for this story:
James Herron at jherron9@bloomberg.net
Helen Robertson

To view this story in Bloomberg click here:
https://blinks.bloomberg.com/news/stories/R0YF1JT0G1L4

Big Oil Producers to Return to Pre-Covid Output in 2022: IEA
2021-10-14 08:00:00.12 GMT

By Julian Lee
(Bloomberg) -- Saudi Arabia, Russia and the U.S. will all return to near pre-covid oil production levels in 2022, with Saudi Arabia expected to exceed its output in the fourth quarter of 2019 by the beginning of next year, the IEA says in its latest monthly report.

* Russian production could rise 120k b/d above its 4Q 2019 level in 2Q 2022, "but further upside would require increased investment in drilling"
* U.S. output will only approach pre-covid rates toward the end of 2022
* By 2Q 2022, spare production capacity will be concentrated in the Middle East, "held primarily by Saudi Arabia, the UAE, Iraq and Kuwait"
* If sanctions on Iran are eased, shut-in capacity of 1.3m b/d could return to the market quickly

To contact the reporter on this story:
Julian Lee in London at jlee1627@bloomberg.net
To contact the editors responsible for this story:
Alaric Nightingale at anightingal1@bloomberg.net
Helen Robertson

To view this story in Bloomberg click here:
https://blinks.bloomberg.com/news/stories/R0YFY8T1UM0X

Energy Crunch to Add 500k b/d to Oil Demand Through 1Q, IEA Says
2021-10-14 08:00:00.5 GMT

By Rachel Graham
(Bloomberg) -- An acute shortage of natural gas, LNG and

coal has triggered a “massive switch” to oil products and direct crude use for power generation, the IEA said in its monthly report.
* This will boost oil demand by 500k b/d from September through 1Q
* Demand for fuel oil, crude and middle distillates was already unseasonably high in August in China, Japan, Pakistan, Germany, France and Brazil
** “Given the extent of the tightness in LNG and coal markets, larger quantities of oil products will be consumed in power plants across a wider range of countries”
* India and China will both use more distillates for back-up generators; that will boost oil demand by 60k b/d and 50k respectively
* India will see 30k b/d of additional demand for naphtha from Indian fertilizer production which would normally run on gas
* READ: Gas-to-Oil Switching, A Trend to Shape Winter Crude Prices
* Graphic ranks additional oil demand by country as follows:
** China, about 100k b/d
** India, about 90k b /d
** Japan, about 70k b/d
** Brazil, about 70k b/d
** Pakistan, about 50k b/d
* Main additional demand will be for fuel oil, then gasoil, then crude oil, then naphtha

To contact the reporter on this story:
Rachel Graham in London at rgraham13@bloomberg.net
To contact the editor responsible for this story:
Alaric Nightingale at anightingal1@bloomberg.net

To view this story in Bloomberg click here:
https://blinks.bloomberg.com/news/stories/R0YEVGDWRGG0

European Oil Demand Set to Drop by 410K B/D Q/Q by Year-End: IEA
2021-10-14 08:00:00.36 GMT

By Prejula Prem
(Bloomberg) -- European oil demand is forecast to decline seasonally by 410k b/d in 4Q 2021, while overall consumption for this year is expected to rise by 460k b/d, the IEA said in its monthly oil market report.
* OECD European oil demand to increase by 570k b/d y/y in 2022
* Quarterly growth in oil demand is projected to be 1.1m in 3Q 2021, led by a rise in jet fuel demand by 345k b/d, to 1m b/d
** Gasoil and gasoline consumption are expected to have risen

q/q by 260k b/d and 250k b/d respectively in the previous quarter

To contact the reporter on this story:
Prejula Prem in London at pprem1@bloomberg.net
To contact the editors responsible for this story:
Alaric Nightingale at anightingal1@bloomberg.net
Fred Pals

To view this story in Bloomberg click here:
https://blinks.bloomberg.com/news/stories/R0YH42DWX2PU

Oil Product Stockpiles to Extend Biggest Drop in 8 Years: IEA
2021-10-14 08:00:00.35 GMT

By Rachel Graham
(Bloomberg) -- Oil product inventories will continue to fall in the fourth quarter, after drawing in 3Q by the most in eight years, the IEA said in its monthly report.
* Refined product balances drew by 1.7m b/d in 3Q
** "Our 4Q forecast sees prolonged tightness in product markets, with stocks expected to continue to draw"
* On crude throughput, the IEA said runs will rise q/q in the fourth quarter, but remain below 2019 levels
** 4Q crude runs forecast at 79.6m b/d, up from 77.9m b/d in 3Q
** 2021 average is 77.4m b/d vs 81.6m in 2019
* In 2Q and 3Q, demand for LPG and naphtha exceeded 2019 levels
** That wasn't the case for gasoline, diesel and jet fuel which "remain the pillar for refinery margins for the majority of refiners with the exception of petrochemical integrated plants"

To contact the reporter on this story:
Rachel Graham in London at rgraham13@bloomberg.net
To contact the editors responsible for this story:
Alaric Nightingale at anightingal1@bloomberg.net
Helen Robertson, Rachel Graham

To view this story in Bloomberg click here:
https://blinks.bloomberg.com/news/stories/R0YGMMDWLU6N

Non-OPEC Supply to Rise by 1.2M B/d in 4Q on U.S., Canada: IEA
2021-10-14 08:00:00.24 GMT

By Sherry Su
(Bloomberg) -- Non-OPEC supply expected to rise by 1.2m b/d

in 4Q to 47.3m b/d by December, supported by strong growth in the U.S., Canada, Norway and Brazil, the IEA said in its monthly Oil Market Report.
* The post-Ida recovery in the U.S. will be supported by growth in the shale patch
* Expanded takeaway capacity in Canada will allow flows to return to record highs, while new projects ramp up in Norway and Brazil, IEA said
* Annual gains for non-OPEC+ will accelerate to 1.8m b/d in 2022 from 390k b/d in 2021
** This assumes that next year U.S. producers step up spending to allow light tight oil output to grow by 620k b/d y/y from 120k b/d in 2021
* Global flows in 2022 expected to suffer less disruption from unexpected outages and prolonged maintenance with pandemic easing

To contact the reporter on this story:
Sherry Su in London at lsu23@bloomberg.net
To contact the editors responsible for this story:
Alaric Nightingale at anightingal1@bloomberg.net
Christopher Sell

To view this story in Bloomberg click here:
https://blinks.bloomberg.com/news/stories/R0YFAVDWX2PT

Natural Gas Crunch Pushes Up Hydrogen Costs for Refiners: IEA
2021-10-14 08:00:00.23 GMT

By Rachel Graham
(Bloomberg) -- The crunch in natural gas has pushed up the cost of hydrogen for refiners, which use it to remove sulfur and other impurities from crude, the IEA said in its monthly report.
* The cost of producing hydrogen averaged around 60c a barrel in 2019
** That's shot up to $5-$6/bbl in recent weeks
* The IEA is now revamping its refining margin methodology to include energy and hydrogen costs
* The refining industry uses about 39 million tons of hydrogen annually, making it the second-biggest consumer, after chemicals
* An average refinery needs 0.1-0.3 mmbtu of natural gas per barrel of crude refined; that can change depending on feedstock and quality standards of the final products
* READ: (Sept. 20) Natural Gas Surge Pushes Up Cost of Key Diesel-Making Ingredient

To contact the reporter on this story:

Rachel Graham in London at rgraham13@bloomberg.net
To contact the editors responsible for this story:
Alaric Nightingale at anightingal1@bloomberg.net
Christopher Sell

To view this story in Bloomberg click here:
https://blinks.bloomberg.com/news/stories/R0YFLMDWLU6J

https://tass.ru/ekonomika/12660305
RUSSIAN ENERGY WEEK - 2021
OCT 14, 01:48Updated Oct 14, 03:28

Energy Minister Says Saudi Arabia Expects Market Balancing By Year End

Prince Abdel Aziz bin Salman also said that OPEC + countries can continue to increase oil production by 400 thousand bpd per month "in the next four months."

MOSCOW, October 14. / TASS /. The oil market may be balanced by the end of 2021 after the pandemic crisis, but there are risks of overproduction of oil as early as 2022. This opinion was expressed by the Minister of Energy of Saudi Arabia, Prince Abdel Aziz bin Salman.

According to him, the oil reserves of the OECD countries, the level of which OPEC + is guided by in its actions, really decreased compared to the 2020 crisis year. "And we think that by the end of this year we will see a very balanced situation. But it is important to always look a little further than the tip of your nose. And if you look at 2022, you will see a lot of excess stocks," he said, noting that "such arithmetic consists of data from eight independent sources."

The minister also added that the OPEC + countries can continue to increase oil production by 400 thousand bpd per month "in the next four months."

The Minister of Energy also said that the situation in the markets for natural gas, liquefied natural gas (LNG) and coal, which are experiencing a period of price peaks, is caused by insufficient investment in these industries and a lack of regulation, like OPEC +.

According to bin Salman, "carbon neutrality should not be an end in itself," as such ambitions disrupt stability in energy markets. “We are already seeing a 500% rise in gas prices, very high coal prices and a 200% rise in LNG prices. undoubtedly, the situation there would be much better now, "he said.

"If we look at the gas and coal market, we see that they need a similar regulator. Perhaps they should just copy past and repeat what we do in the oil market," he suggested.

The International Forum "Russian Energy Week" is a discussion platform in Russia aimed at discussing the challenges and prospects for the development of the world fuel and energy complex. This year the conference is being held in the Moscow Manege on October 13-15. In total, the forum will include more than 30 business events, in which the heads of more than 200 companies from various sectors of the fuel and energy complex will take part. Also, within the framework of the REW, the Global Energy Prize laureates will be awarded. By tradition, the program of the forum will end on October 15, the youth day.

https://www.libyaherald.com/2021/10/11/libya-on-brink-of-another-west-east-split-and-unravelling-of-lpdfs-road-map/

Libya on brink of another west-east split and unravelling of LPDF's Road Map?

By Sami Zaptia.

Deputy Prime Minister Hussien Gatrani is threatening escalation if his Prime Minister does not become more conciliatory (Photo: GNU)

London, 11 October 2021:

With the 24 December 2021 elections looking in the balance, Libya looked like it was heading into another west-east split and an unravelling of the November 2020 Libyan Political Dialogue Forum's (LPDF) Roadmap yesterday.

The threat of political breakdown came in the form of a statement read out by Hussien Gatrani, Deputy Prime Minister of Libya's Government of National Unity (GNU). Al-Gatrani, who hails from the east, was issuing the televised statement in front of a gathering of Libya's eastern based (Barqa/Cyrenaica) Deputy Ministers, Ministers and mayors in Benghazi.

In his ten-point statement, Gatrani:

1. Affirmed that his boss, Prime Minister Abd Alhamid Aldabaiba, has not committed to implementing the terms of the LPDF Road Map and its governing principles of unifying institutions and equitable distribution of capabilities/assets/power through the correct legal methods between the regions.
2. Said the Aldabaiba's GNU did not rise to the level of national and historical responsibility and fell into the paths of individual management and personal accounts. The GNU is weakening institutional and executive work.
3. The GNU did not succeed in managing political difference.
4. The GNU did not commit to defining the terms of reference for the Deputy Prime Ministers.
5. Demanded the return of the central administrative institutions and units that had previously been located in Cyrenaica.
6. Demanded the reopening of the electronic bank clearing system.
7. Demanded the activation of all the terms of the LPDF Road Map to guarantee the rights of the regions and the guarantee of the rights of the Libyan people urgently.
8. PM insisting on holding the Defence Minister portfolio for himself and refusing to appoint a standalone Defence Minister.
9. Condemned some media statements made by Prime Minister as divisive.
10. Called on the Prime Minister of the GNU to take all measures to urgently address these points in order to avoid escalatory measures.

Analysis

A roadmap, within a roadmap within a roadmap

The November 2020 LPDF Roadmap is Libya's current political roadmap – within the 2015 Skhirat Libyan Political Agreement (LPA) which is in turn within the Transitional Constitutional Declaration (TCD) of August 2011.

The LPA was the political fix after militias carried out a coup in Tripoli in 2014 in reaction to losing power after the 2014 elections. The 2011 TCD was the temporary social contract to fill the void left by the collapse of the 42-year Qaddafi regime.

The current Government of National Unity (GNU) led by Abd Alhamid Aldabaiba is the selected child of the LPDF Road Map. The original 74 LPDF members were chosen by UNSMIL to broadly represent Libya.

UNSMIL and the international community created the LPDF to get passed Libya's political impasse and quagmire where parliament (the House of Representatives – HoR), the High State Council and the Faiez Serraj Government of National Accord (GNA) failed to achieve consensus and move forward to elections to get the country out of its ''interim'' state.

Centrifugal effect of threat of elections?

It seems that the threat of Libyan elections in December this year, or soon afterwards, is having a centrifugal effect on Libyan politics. There is a fear of change and the forthcoming political unknown by the status quo stakeholders who fear losing power or even being vulnerable to prosecution or persecution after any elections that may sweep the old political guard aside.

LPDF political quid-pro-quo

The implication of Gatrani's statement is that there was a written and an unwritten agreement of a quid pro quo, that in return for Khalifa Hafter, parliament and eastern Libya, buying into the Aldabaiba GNU – the GNU would make real political concessions to the east. This included moving forward with decisions after consultation and in consensus.

Aldabaiba monopolising power?

Aldabaiba is accused of being on a state-sponsored election campaign and of taking decisions unilaterally. He is accused of refusing to appoint a stand-alone Defence Minister in order to consolidate his military and political hold on western Libya and indirectly on the other two regions.

Tripoli centralisation of power?

Gatrani accuses Aldabaiba of increased centralization rather than Aldabaiba's claim of decentralizing powers to the regions and local councils. This includes the effective refusal to return the National Oil Corporation (NOC) to its original site in Benghazi. Tripoli has failed to reopen the bank clearing system closed during Hafter's war on Tripoli in order to starve eastern based banks accused of financially supporting Hafter.

Reopening the bank clearance system

The 23 October 2020 ceasefire agreement (which ended Hafter's war on Tripoli) through which Hafter allowed the eastern-based oil supplies to flow again prescribes for the reopening of the bank clearance system. The closure of the clearance system is causing huge hardship to Libyans in the east and stunting the regions development. It is also threatening to collapse the whole Libyan banking system which is now lopsided.

Aldabaiba divisive?

Gatrani also accused Aldabaiba of playing to the western-based gallery by being divisive in some of his media statements – rather than attempting to seek a middle path to keep the opposing Libya political outlooks united.

Gatrani threatening escalation?

At the end of the statement, Gatrani threatened escalatory measures by the east. The Aldabaiba government has already been downgraded to a ''caretaker'' government, but its public relations / propaganda machine seems to be going into overdrive – or election campaign mode.

Every road or clinic or building completed is now a huge PR event for the government for the next three months.

5+5 JMC agreement

Its ironic that the political strata is falling out at just the time when the two sets of military heads have reached an historic agreement in Geneva to start organized and coordinated withdrawal of their aligned foreign militias/forces.

Escalation: stopping oil production v war?

The room for political manoeuvre is limited for the east short of going nuclear and shutting down oil production or all-out war. There is little leverage they have on Tripoli. The government has been demoted but it falls to the Tripoli-based Central Bank of Libya and Audit Bureau to agree or stop its spending decisions.

It now falls to the international community to try to broker between the two sides to deescalate the tension. But it seems the closer Libya gets to just the idea of elections the higher the stakes and the higher the risks being taken by both sides of Libya's political divide.

OIL DEMAND MONITOR: U.S. Air Travel Recovery Swifter Than Europe

- Europe air traffic down 28% vs 2019; global figure down 20%
- Rome traffic levels swelled Monday to unusually high levels

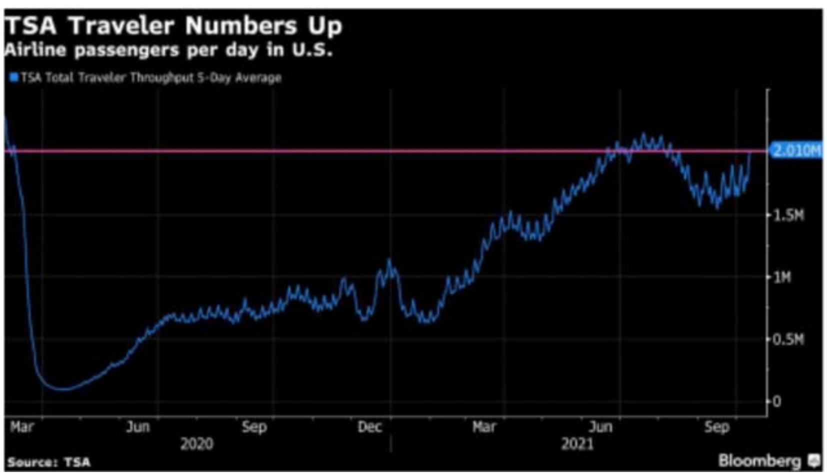
Oct 13, 2021 04:01:24

By Stephen Voss

(Bloomberg) -- Air travel has recovered gradually in the U.S. and is almost back to normal while the more fragmented European airline industry is taking longer to claw its way back to pre-pandemic levels, according to high-frequency data.

A five-day average of the number of passengers passing through U.S. airport turnstiles surpassed 2 million a day for the first time since mid-August, and the level on Oct. 11 was only 10% below the equivalent weekday in 2019, government data showed. Separately, an Energy Information Administration estimate of jet fuel demand in the U.S., which can often be volatile, was just 4.3% below pre-pandemic levels in the week ended Oct. 1.

Compare that with European air traffic that still lagged the equivalent period of 2019 by 28% as of Oct. 11, according to Eurocontrol, a flight-monitoring agency for nations on the continent. For the world as a whole, the number of commercial flights is 20% less than two years ago, according to the latest daily estimate by FlightRadar24.



The number of seats offered by airlines, as measured weekly by OAG Aviation, also shows European nations trailing behind the U.S., Mexico and India when comparing the latest levels against 2019. On that basis, China remains top, with capacity only about 5% less than two years ago, while the U.S. is down 14% and the U.K. and Germany are both down by about 45%.

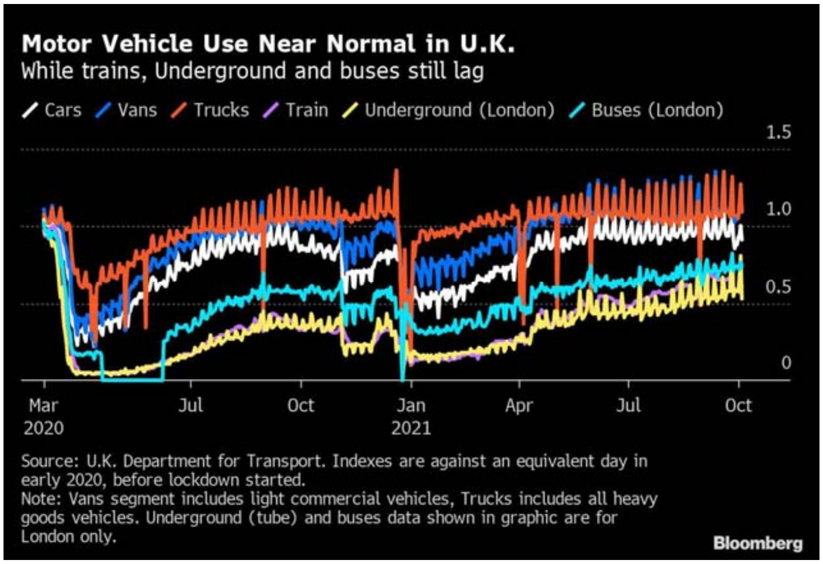
Busy Roads in Rome

Traffic levels within major world cities were somewhat erratic on Monday, according to TomTom NV data. Congestion at 8 a.m. local time soared in Rome while collapsing to very low levels in Mumbai, Madrid, New York, Tokyo and Sao Paulo. Holidays in the U.S. and Brazil probably contributed in part.

In the Italian capital, congestion leapt to 107%, meaning that a journey that would take one hour on empty roads now had an extra 64 minutes, for a total trip time of two hours and four minutes. That level of added congestion time was about a third more than the typical amount in 2019 for that time of the week.

London and Paris also had more congestion than before the pandemic on Monday while other citiesregularly watched in this monitor had less.

Motor vehicle activity in Britain is back to 96% of what it was before the pandemic hit in early 2020, with more trucks and vans on the road and slightly fewer cars, according to daily measurements by the Department for Transport. Commuters are less fond of mass transit though, with the London Underground, nationwide trains and London buses ranging from between 53% and74% of pre-pandemic levels.



Some oil market observers are speculating that demand, especially in Asia, will receive a boost because high natural gas prices are forcing consumers and power producers to diversify to other fuels, and this sometimes includes diesel or fuel oil. In the coming winter season, such switchingmay add as much as 500,000 barrels a day of extra oil demand, according to Facts Global Energyanalysts.

READ (Oct. 6) Gas-to-Oil Switching: A Trend to Shape Winter Crude Prices

The Bloomberg weekly oil-demand monitor uses a range of high-frequency data to help identifytrends that may become clearer later in more comprehensive monthly figures.

Following are the latest indicators. The first two tables show fuel demand and mobility, the nextshows air travel globally and the fourth is refinery activity:

Measure	Location	y/y	2019	m/m	Freq.	of Date	Latest Value	Source
Gasoline demand	U.S.	+6	-0.3	-1.9	w	Oct. 1	9.43m b/d	EIA
Distillates demand	U.S.	+13	+8.2	+18	w	Oct. 1	4.37m b/d	EIA
Jet fuel demand	U.S.	+87	-4.3	+4.4	w	Oct. 1	1.69m b/d	EIA
Total oil products demand	U.S.	+17	+0.5	+7.9	w	Oct. 1	21.5m b/d	EIA
All vehicles miles traveled	U.S.		-1		w	Sept. 26	16.5b miles	DoT
Passenger car VMT	U.S.		-4		w	Sept. 26	n/a	DoT
Truck VMT	U.S.		+11		w	Sept. 26	n/a	DoT
All motor vehicle use index	U.K.	+5.5	-4	-4	d	Oct. 4	96	DfT
Car use	U.K.	+5.8	-9	-5.2	d	Oct. 4	91	DfT
Heavy goods vehicle use	U.K.	+2.8	+9	unch	d	Oct. 4	109	DfT
Gasoline (petrol) avg sales per filling station	U.K.	+19	+4.6	+11	m	Sept. 27-Oct. 3	7,622 liters/d	BEIS
Diesel avg sales per station	U.K.	+11	+0.5	+15	m	Sept. 27-Oct. 3	10,503 liters/d	BEIS
Total road fuels sales per station	U.K.	+14	+2.2	+14	m	Sept. 27-Oct. 3	18,125 liters/d	BEIS
Gasoline	India	+6.6	+8.8	+3.6	2/m	Sept. 1-30	2.35m tons	Bberg
Diesel	India	+0.8	-6.5	+5.7	2/m	Sept. 1-30	4.88m tons	Bberg
LPG	India	+3.7	+9	+5.9	2/m	Sept. 1-30	2.36m tons	Bberg
Jet fuel	India	+24	-40	+9.6	2/m	Sept. 1-30	373k tons	Bberg
Total Products	India	+11	-6.6	-4.9	m	August	16m tons	PPAC
Passenger car traffic	Poland	+3	+4	-10	m	September	24,062	GDDKiA
Heavy goods traffic	Poland	+5	+9	+6	m	September	4,786	GDDKiA
Toll roads volume	Italy	+9.8	-0.5		w	Sept. 27-Oct. 3	n/a	Atlantia
Toll roads volume	Spain	+31	-2.5		w	Sept. 27-Oct. 3	n/a	Atlantia
Toll roads volume	France	+15	+1.7		w	Sept. 27-Oct. 3	n/a	Atlantia

Toll roads volume	Brazil	+2.5	+1.9		w	Sept. 27-Oct. 3	n/a	Atlantia
Toll roads volume	Chile	+44	+14		w	Sept. 27-Oct. 3	n/a	Atlantia
Toll roads volume	Mexico	+11	+8.3		w	Sept. 27-Oct. 3	n/a	Atlantia
All vehicles traffic	Italy	+5.7		-7.1	m	September	n/a	Anas
Heavy vehicle traffic	Italy	+5.7		+25	m	September	n/a	Anas
Gasoline	Portugal	+8	-7.7	+9.1	m	August	103k tons	ENSE
Diesel	Portugal	+5.5	-6.5	+0.5	m	August	421k tons	ENSE
Jet fuel	Portugal	+64	-36	+18	m	August	100k tons	ENSE
Gasoline	Spain	+14	+4.7		m	August	558k m3	Exolum
Diesel	Spain	+7.9	-2.3		m	August	2147k m3	Exolum
Jet fuel	Spain	+77	-41		m	August	448k m3	Exolum

Note: Click here for a PDF with more information on sources, methods. The frequency column showsfor data updated daily, w for weekly, 2/m for twice a month and m for monthly.

* In DtT U.K. data, the column showing versus 2019 is actually showing the change versus the firstweek of February 2020, to represent the pre-Covid era.

** In BEIS U.K. data, which is only released once per month, the column showing versus 2019 is actually showing the change versus the average of Jan. 27-March 22, 2020, to represent the pre- Covid era.

City congestion:

Measure	Location	% chg vs 2019	% chg m/m	Oct. 11	Oct. 4	Sept. 27	Sept. 20	Sept. 13	Sept. 6	Aug. 30	Aug. 23	Aug. 16
		(Oct. 11)		Minutes of congestion at 8am local time								
Congestion	Tokyo	-68	-62	12	34	35	0	32	28	28	28	11
Congestion	Mumbai	-97	-89	1	7	11	12	11	10	5	8	7
Congestion	New York	-73	-78	8	35	31	35	39	0	15	16	13
Congestion	Los Angeles	-34	-24	23	27	30	28	31	2	29	27	24
Congestion	London	+16	-1	44	43	53	44	44	37	1	16	15
Congestion	Rome	+32	+57	64	44	53	55	41	31	13	5	2
Congestion	Madrid	-92	-91	3	41	35	35	33	20	6	3	2
Congestion	Paris	+9	-7	49	52	52	53	52	49	27	14	9
Congestion	Berlin	-41	-38	20	38	31	29	32	38	32	38	29
Congestion	Mexico City	-43	unch	28	29	26	29	28	27	24	23	20
Congestion	Sao Paulo	-76	-62	10	29	26	26	27	10	30	26	25

Source: TomTom. Click here for a PDF with more information on sources, methods.
NOTE: m/m comparisons are Oct. 11 vs Sept. 13. TomTom has been unable to provide Chinese datasince late April. The U.S. had a holiday on Oct. 11 and Brazil on Oct. 12.

Air Travel:

Measure	Location	% chg y/y	% chg vs 2019	% chg m/m	Freq.	Latest as of Date	Latest Value	Source
Airline passenger throughput	U.S.	+117	-10	+25	d	Oct. 11	2.08m people	TSA
Commercial flights	Worldwide	+38	-20	+1.9	d	Oct. 11	94,724	FlightRadar24
Air traffic (flights)	Europe		-28	-4.9	d	Oct. 11	23,557	Eurocontrol
Seat capacity	Worldwide	+37	-29		w	Oct. 11	79.35m	OAG
Seat cap.	U.S.	+65	-14		w	Oct. 11	19.15m	OAG
Seat cap.	China	-4.1	-5.2		w	Oct. 11	15.31m	OAG
Seat cap.	India	+59	-21		w	Oct. 11	3.32m	OAG
Seat cap.	Spain	+125	-26		w	Oct. 11	2.46m	OAG
Seat cap.	Japan	-5.7	-49		w	Oct. 11	2.08m	OAG
Seat cap.	U.K.	+76	-45		w	Oct. 11	1.96m	OAG
Seat cap.	Germany	+89	-44		w	Oct. 11	1.92m	OAG
Seat cap.	Brazil	+38	-29		w	Oct. 11	1.82m	OAG
Seat cap.	Mexico	+50	-7.4		w	Oct. 11	1.66m	OAG
Seat cap.	France	+61	-38		w	Oct. 11	1.44m	OAG
Seat cap.	Australia	+26	-74		w	Oct. 11	547k	OAG
Seat cap.	S. Africa	+83	-45		w	Oct. 11	329k	OAG
Seat cap.	Singapore	+138	-82		w	Oct. 11	149k	OAG

NOTE: Comparisons versus 2019 are a better measure of a return to normal.

Refineries:

Measure	Location/area	y/y chg	vs 2019 chg	m/m chg	Latest as of Date	Latest Value	Source
		Changes in ppt unless noted					
Crude intake	U.S.	+14%	+0.6%	+10%	Oct. 1	15.7m b/d	EIA
Utilization	U.S.	+13	+3.9	+7.7	Oct. 1	89.6 %	EIA
Utilization	U.S. Gulf	+14	+1.1	+13	Oct. 1	88.5 %	EIA
Utilization	U.S. East	+25	+28	+4	Oct. 1	89.1 %	EIA
Utilization	U.S. Midwest	+7.8	+6.6	+5.1	Oct. 1	94 %	EIA
Apparent Oil Demand	China	+0.7%		+1.1%	August 2021	13.61 b/d	NBS
Indep. refs run rate	Shandong, China	-6.1	+1.4	-0.4	Sept. 30	68.1 %	SCI99
State refs run rate	East China	+0.3	-1.2	+2	Sept. 30	81.4 %	SCI99
State refs run rate	South China	+0.7	+1.6	+2.2	Sept. 30	84.1 %	SCI99

NOTE: All of the refinery data is weekly, except for SCI99 state refineries, which is twice per month, and the NBS apparent demand, which is usually monthly. Changes are shown in percentage point except for the rows on crude intake and apparent oil demand, which are shown in percent change.

Google Translate of http://www.gov.cn/premier/2021-10/11/content_5641907.htm

Li Keqiang presided over a meeting of the National Energy Commission, emphasizing on ensuring stable energy supply and safety, enhancing the ability to support green development and Han Zheng attended the meeting

2021-10-11 21:06 Source: Xinhua News Agency

Xinhua News Agency, Beijing, October 11th. On October 9, Li Keqiang, member of the Standing Committee of the Political Bureau of the CPC Central Committee, Premier of the State Council, and Director of the National Energy Commission presided over a meeting of the National Energy Commission to deploy energy reform and development work and deliberate the "14th Five-Year Plan" modern energy system plan. , Energy and carbon peak implementation plan, suggestions on improving the system and mechanism of energy green and low-carbon transition and policy measures, etc.

Han Zheng, member of the Standing Committee of the Political Bureau of the CPC Central Committee, Vice Premier of the State Council, and Deputy Director of the National Energy Commission attended the meeting.

On October 9, Li Keqiang, member of the Standing Committee of the Political Bureau of the CPC Central Committee, Premier of the State Council, and Director of the National Energy Commission hosted a meeting of the National Energy Commission in Beijing. Han Zheng, member of the Standing Committee of the Political Bureau of the CPC Central Committee, Vice Premier of the State Council, and Deputy Director of the National Energy Commission attended the meeting. Photo by Xinhua News Agency reporter Ding Haitao

At the meeting, the Development and Reform Commission and the Energy Administration made reports. Li Keqiang said that energy is a major issue related to the overall economic and social development. During the "Thirteenth Five-Year Plan" period, under the strong leadership of the Party Central Committee with Comrade Xi Jinping as the core, all parties worked together to achieve remarkable results in my country's energy development, structural optimization, and efficient and clean utilization. At present, the international environment and global energy structure and system are undergoing profound changes, and my country's energy development and security are facing new challenges. It is necessary to adhere to the guidance of Xi Jinping Thought on Socialism with Chinese Characteristics for a New Era, implement the deployment of the Party Central Committee and the State Council, follow the requirements of building a new development pattern, building a new development pattern, and promoting high-quality development based on the new development stage, implement the new development concept, and proceed from the actual conditions of the country. Improve the relationship between development and emission reduction, current and long-term development, coordinate stable growth and structural adjustment, deepen market-oriented reforms in the energy sector, promote green and low-carbon transformation of energy, improve energy security capabilities, and provide solid support for modernization.

Li Keqiang pointed out that energy security is related to development security and national security. my country is still a developing country, and development is the foundation and key to solving all problems. At this stage, industrialization and urbanization are intensifying, and energy demand will inevitably continue to grow. Supply shortage is the biggest energy insecurity. We must build a modern energy system on the premise of ensuring safety, and strive to improve the ability of independent energy supply. Aiming at the endowment of coal-based energy resources, the layout of coal production capacity should be optimized, advanced coal-fired power should be constructed rationally according to development needs, and backward coal-fired power should be eliminated in an orderly manner. Increase domestic oil and gas exploration and development, actively develop shale gas and coalbed methane, and carry out diversified international oil and gas cooperation. Strengthen the construction of gas and oil storage capacity, promote the large-scale application of advanced energy storage technology, and continuously enrich the insurance tools for safe energy supply.

Li Keqiang said that achieving carbon peak and carbon neutrality is a requirement for the transformation and upgrading of my country's economy, and it is also a requirement for jointly responding to climate change. To advance the realization of the "dual carbon" goal in a scientific and orderly manner, long-term arduous efforts must be made. It is necessary to take into account the recent situation of dealing with the contradiction between power and coal supply and demand, in-depth calculations and demonstrations, and study and put forward the timetable and roadmap of the steps to reach the peak of carbon. All localities and all relevant parties must insist on breaking first and then breaking, insisting on a game of chess across the country, and not rushing away. Proceeding from reality, we should correct the “one size fits all” power restriction or campaign-style “carbon reduction” in some places, to ensure that the people in the north can survive the winter warmly and safely, and ensure the stability of the industrial supply chain and the sustained and stable economic development. Vigorously promote the clean utilization of coal, increase the proportion of clean energy, deepen the transformation of energy conservation and emission reduction in key areas, advocate energy conservation in the whole society, and continuously improve the capacity for green development.

Li Keqiang pointed out that innovation is an important driving force for the high-quality development of energy. It is necessary to speed up the research on key core technologies and equipment in the energy field, and strengthen the research and development of green and low-carbon cutting-edge technologies. Improve the intelligent level of the power grid, and enhance the ability to absorb new energy and safe operation. Improve tiered electricity prices, deepen reforms in key areas such as power transmission and distribution, rely more on market mechanisms to promote energy conservation, emission reduction and carbon reduction, and improve energy service levels.

Sun Chunlan, Hu Chunhua, Liu He, Wang Yong, Wang Yi, Xiao Jie, He Lifeng, and relevant units and heads of some enterprises attended the meeting.

still at historically low levels, investors need solutions that can earn a real yield and be resilient in a higher inflationary world. Inflationary trends are appearing more than transitory, reflecting structural changes, including a shift from consumerism to job creation, rising wage growth and the energy transition.

As I said in a speech to the G20 in July, society needs to rapidly invest in innovation to offset inflationary pressures associated with the transition to a net zero economy. We need to make sure that we are pushing just as hard on the demand side as we are on the supply side. Otherwise, we risk supply issues that drive up the cost for consumers, especially for those who can least afford it. Against this backdrop, clients are turning to BlackRock more than ever before, and we are using the full breadth of our capabilities to meet all our clients' needs.

BlackRock's top-performing active platform continues to outpace the industry, generating $45 billion of net inflows in the quarter and nearly $200 billion over the last 12 months. Momentum in active equities continue, and BlackRock's No. 1 in year-to-date asset-gathering in the U.S. active equity mutual fund industry, up from No.

3 in 2020. These results reflect our investments over time to incorporate data science, integrate ESG considerations and enhancing portfolio construction capabilities across the entire active business. And we remain committed to continuous innovation so we can deliver strong and durable alpha for our clients over the long term. In addition to our traditional active strategies, we're also seeing clients increase portfolio allocation to private markets.

As they reach for yield, institutions are turning to BlackRock for private credit, real estate and private equity solutions. And well, we are seeing advisors access private markets through our record -- our recent closed-end fund vehicle, which have up to 25% allocation to alternatives and our accredited investor solutions. In total, we raised about $5 billion of illiquid alternative flows and commitments in the quarter, and we continue to steadily deploy that capital for our clients. Portfolio construction and asset allocation decisions are critical in achieving desired returns, and more clients are adopting our ETFs as a building block in their portfolios.

We generated $58 billion of ETF net inflows in the third quarter with growth across each of our core strategic and precision product categories, including strong flows in fixed income as clients sought inflation protection and sources of income. We crossed $200 billion in ETF inflows year to date, exceeding our 2020 full-year flows. We are seeing this momentum across the entire ETF industry as more and more investors discover the convenience, the efficiency and the transparency that the ETF vehicle has. We see opportunities well beyond the 30 million people who use our ETFs today and continue to believe in the long-term growth potential for ETFs.

Hey. Good morning. Thanks for taking the question. Just wanted to ask about alternatives, given prospects here for rising yields and interest rates, there's some fear in the marketplace that this could soften flows into alternative products.

So I just would be curious to hear your perspective on how you see a potential for investor allocations to alternative products to evolve in a rising rate scenario. And then as you look across your alternatives franchise today, maybe you could just touch upon some of your recent initiatives on illiquids and just any sort of views on which you think could be the largest contributor to growth at BlackRock among your illiquid products. Thank you.

Larry Fink -- *Chairman and Chief Executive Officer*

Well, first of all, hi, Michael. I'm going to let Rob Kapito answer that question.

Rob Kapito -- *Head, Portfolio Management Group*

So Michael, as you know that we have been involved in the alternatives business in one way or another for a pretty long time, especially in the retail sector since 1988. And our goal has been to access the retail area for alternatives by keeping our promises over a long period of time on performance. So to start with the growth in retail alternatives is certainly compelling as part of our strategy to serve advisors' whole portfolios. And what we chose to do is bring a diversified product lineup to the retail alternative investor.

So our job is to bring the appropriate wrappers for those products that provide the solutions to help reshape their portfolio at a period of time when rates and returns have been very low. And what we've seen them do is move from 1% to 2% of their portfolio to allocations up to 20%. So year to date, just in that sector, we've raised over $24 billion of net inflows, and that's at approximately 85 basis point average fee rate across what we'll call our retail liquid alternatives and credit vehicles, and our public-private closed-end fund offerings. So our recent launch of alternatives portfolio analytics for financial advisors on the web-based BlackRock Advisor Center and the continued product expansion is going to help us grow with those clients.

And in the recent years, as we expanded our retail alternatives to include private credit and private equity, pre-IPO access to growth equity through closed-end funds, and we're working to expand our retail alternatives offerings now across real assets, sustainable and co-investment opportunities. So just in the closed-end funds alone, we provide a wrapper that will enable us to provide up to $3 billion and alternatives to them. And just in a summary form, in total, we manage about $180 billion across liquid and illiquid alts, $29 billion right now in dry powder to invest and deploy, approximately $210 million of future annual base fees. And including liquid and liquid credit, our platform is now over $310 billion.

We're the top 5 manager in that. And we've built out alternatives platforms and raised another $100 billion of gross capital over the last five years, and we expect to raise $100 billion more in the next three years. So just for September year to date, we have raised $25 billion of gross capital and deployed $10 billion and because there is some expectation that rates can rise, still, these are longer-term investments that have enough spread in it, that I believe that the demand is going to continue for quite a long period of time. And I think Larry's rate scenario, which you said in the beginning, as rates low for longer, will only enhance the ability for people to want more alternatives.

Operator

And your next question comes from Alex Blostein with Goldman Sachs. Your line is open.

Larry Fink -- *Chairman and Chief Executive Officer*

Hi, Alex.

Alex Blostein -- *Goldman Sachs -- Analyst*

Great. Good morning. Hi, Larry. Thank you for taking the question.

So inflation concerns are clearly everywhere in the area. As you highlighted in your prepared remarks, that's something you guys are clearly focused on as well. So maybe a two-part question here. So one, when it comes to BlackRock's own cost structure, where are you seeing expense growth and margins heading into '22? We obviously saw you made changes on the salary front last quarter but curious if this is becoming a bigger issue for sort of total comp and G&A as you think forward.

And then secondly, from a product perspective, what are the strategies you're advising clients to lean into more aggressively into 2022 to protect their portfolios against the upside inflation risk? Thank you.

Larry Fink -- *Chairman and Chief Executive Officer*

You take the expense first.

Gary Shedlin -- *Chief Financial Officer*

Hey, Alex. It's Gary. How are you? So we're obviously -- we have seen some expense growth, which I think is expected in the context of the outsized organic base fee growth that we're delivering on the top line. For the third quarter, our margin obviously was down about 120 basis points versus a year ago.

And I'd say there are a couple of things there that kind of clouded what would have been some operating leverage in the business. Really three things in particular. One was

Finally, on the direct fund expense side. I think that is purely variable. That is obviously tied in most part to our growth in our index AUM, which is fundamentally driven by our success in iShares. That number was up roughly 38% year over year, but there's always going to be some noise in that number as we try to effectively manage that expense on behalf of the fund shareholders.

So in this case, this year, while there are some timing issues, it did reflect some onetime expenses associated with moving indexes from one provider to a next to try and basically get those at lower cost. And when you exclude a little bit of the noise, that number was probably up about 31% year over year versus average iShares AUM increase of close to 34%. So I would say, yes, there's some expense increase. I would say it's less tied to inflation for us than other players.

It's really more tied to continuing to invest for growth. And obviously, if we're able to continue to deliver organic base fee growth, well in excess of our 5% target, which we've done for the last six quarters in a row to 9% clip, 13% over the last 12 months, we're going to see some elevated expenses to be able to drive that success.

Larry Fink -- *Chairman and Chief Executive Officer*

And on the products in a more inflationary environment. I would just clearly tell you that our platform is large. It's diverse. We're having conversations with clients globally where they should be allocating.

I do believe you're seeing higher allocation toward equities over the last year across our clients' portfolios. As equities rallied, they did less in terms of rebalancing. The bigger question is how do you allocate across equities. What is the roll-up in emerging markets? But I don't think inflation is playing a dominant role in the conversations, even in fixed income where obviously it's very obvious, long-duration assets are going to be the impacted the most.

And so those clients in fixed income were worried about their duration risk. It could go down into a low duration product. They could go into various different products with less convexity and less issues. They could go in some type of inflationary protected type of notes, too.

That's not going to be that large. But the resiliency of our platform really allows us to have that conversation, whether it's in a deflationary world or in an inflationary world. And I do believe the -- if you look at the geographic dispersion of our growth, the conversations worldwide represent these types of conversations, what should we think about inflation; what role should we play; what is the role of alternatives in an inflationary environment; what is the role of equities and across fixed income. So I actually believe it's the volatility of the global economy is allowing us to have these robust deep conversations.

And I don't think there's one global trend going in and out of one product because inflationary fears and some clients don't believe in that. Some people actually believe it's transitory. So I mean that's the -- I would look at this -- when there is uncertainty and when we're in a transition period, more clients come to BlackRock than ever before because they're asking those questions. And I think because of the robustness of our platform, whether it's an index-oriented strategies or active strategies across the spectrum, we have the ability to work with them across all economic environments.

Operator

Your next question comes from Brian Bedell with Deutsche Bank. Your line is open.

Brian Bedell -- *Deutsche Bank -- Analyst*

Great. Thank you. Hey. Good morning, everyone.

Maybe just switch gears to the sustainable investing growth. I think, Larry, you were -- you made some comments at a conference on the path to net zero that, but at the current rate, we're not there yet. Maybe if you can talk about how you think the demand and the capacity for BlackRock to offer impact fund products, more impact fund products, you already have the carbon readiness and the Temasek JV going forward. And is that going to be -- should we be thinking of that as a pretty strong organic growth path going forward?

Larry Fink -- *Chairman and Chief Executive Officer*

Well, flows in this COVID world that accelerated into sustainable products. Let me give you the context. I think the global capital markets, public institutions are moving very rapidly to adapt more disclosures related to sustainability. More clients, including our hydrocarbon clients, are looking to adapt how to continue to provide hydrocarbons to fit the needs of -- the current needs of our society, but also slowly adapt in a more sustainable platform, too.

So across the board, we are having very deep and deep conversations. And I must say the conversations we're having that with the hydrocarbon companies and the hydrocarbon, from chemicals to oil, they are more robust than ever. They're deeper, they're broader than any other time. And -- but our flows continue to grow and dominate.

We continue to be a dominant leader. Year to date, we had about $80 billion of sustainable inflows. We had $32 billion of those inflows in the third quarter. When I talked about the shift in finance, we're seeing that.

Now specifically on your question related to impact, this is one of the reasons why we wanted to be a partner in breakthrough energy. We want to learn more of the science and the new technologies. This is why we partnered in our decarbonization fund with Temasek. The demand is growing precipitously in terms of clients interested in finding new -- be part of this transition.

And so the capital is there. What is not as prevalent or the projects, are the opportunities. We are having conversations with universities. We're having conversations with governments across the board on how can we provide capital.

And one of the more dynamic conversations we're having with the traditional hydrocarbon companies across the board is, how can we partner with them in terms of moving -- helping them move forward on their sustainable strategies, on their decarbonization strategies, on their strategies around sequestering of their own carbons? I mean so many of the big multinational hydrocarbon companies are building new dynamic technology so they can be the leaders in the sequestering of hydrocarbons of carbons at the same time that they may be using that to produce more energy at this time. But these are the types of solutions we're having across the board. You've heard the questions with my view is we're not moving fast enough. Yes, I think the movement toward sustainability is very fast and rapid related to public companies.

I think regulators worldwide are asking public companies and banks to do more disclosure. My greatest fear, and I spoke about this in my Venice speech three months ago, is we're creating a hybrid world, a bifurcated world the pressure on public companies and banks and asset managers are enormous. We're not putting any pressure on private companies. And there was a great story today in one of the newspapers about as hydrocarbon companies divested some of their hydrocarbons, the buyers are private equity firms.

OK. That doesn't change the net-zero world, and that's why I'm saying we're never going to get to a net-zero world, if we're not moving holistically together public and private. And then I spoke about, obviously, in editorial today related about the need to invest in the emerging world. There is huge pools of capital standing by, but there, we are not able to evaluate the first loss piece in so many of the brownfield investing in the emerging world.

And it is estimated the emerging world needs $1 trillion a year to become more sustainable. As a backdrop, the emerging world minus China represents 34% of the hydrocarbon output. And so if we are going to continue at the pace of $150 billion of investments, when there's a need of $1 trillion, we're fooling ourselves are we going to get to a net-zero world. We're going to be fooling ourselves to getting to a net-zero world if we're only asking public companies.

We are fooling ourselves if we believe by restricting supply with our traditional hydrocarbon companies, that only raises energy costs, which we're witnessing now. And that is creating not a just transition, which I spoke about in my last two CEO letters. So we have to be vocal. We have to be forceful about it.

BlackRock is a leader in this, and we are seeing the flows, and I continue to see this big shift in investor portfolios. As they move away from traditional indexes to more sustainable types of indexes, as they're moving away from different types of strategies and they're moving into these other strategies, we need to accelerate this. We need to accelerate in a way that we're working with our great hydrocarbon companies, not against them.

Operator

Your next question comes from the line of Bill Katz with Citigroup. Your line's open.

Bill Katz -- *Citi -- Analyst*

OK. Thank you very much.

Larry Fink -- *Chairman and Chief Executive Officer*

Hey, Bill.

Bill Katz -- *Citi -- Analyst*

Good morning, everybody, and thank you so much for taking the questions today. OK. Maybe a two-part question, just keeping in line with that. One is can you maybe peel back a little bit on why you're so successful in the retirement business.

And where do you sort of see the paychecks opportunity gaining scale and share? And then completely unrelated, but maybe for Gary, how do you think about the exit fee rate -- base fee rate, just given the divergent beta versus the very strong flow mix dynamics?

Rob Kapito -- *Head, Portfolio Management Group*

So Bill, the story is we are able to look at a client's portfolio holistic over the long term, and the focus is to have our clients be able to retire in dignity. It's not a one-off situation. It's a constant look at a portfolio over a period of interest rates and solve the problem with the appropriate wrappers and products. We have the scale of products, we have the performance, we have the wrappers.

So honestly, it is the focus. A significant portion of all of BlackRock's assets are dedicated to retirement. This is what we do. And when we dovetail that into the analytics that we could provide, we really can fulfill the entire gamut of retirement.

So it's product, performance and technology and focus on what we think is the most important business that there is in the world is keeping our promises to clients so they can retire in dignity.

Larry Fink -- *Chairman and Chief Executive Officer*

So Bill, I would add one more thing that Rob was talking about. I think our consistency of messaging to our clients across many, many years. And we've built a deep relationship with the clients. And I don't believe our 9% growth rate is a onetime thing.

I think we continue to be growing our presence in this market. We continue to try to be an innovator, whether it's the LifePath Paycheck or -- which now we LifePath Paycheck about $340 billion. I'm sorry, that's our target date and LifePath Paycheck, our most recent growth. So I look -- I think conversations have never been broader, more robust, and we continue to drive these conversations.

I believe more and more of the large plans are looking to BlackRock for that type of advice, that type of handholding. And I believe more than ever before, especially in this world of need for more employees, the need to build deeper relationships with our employees, I believe the conversations at every corporation now, in how to create better connectivity with their employees, is becoming a broader conversation than we've ever seen in the last 20 years. I think the companies that have deeper connections, they better -- a better retirement plan, better healthcare plans, better healthcare plans are the companies that are driving more consistency with their employees, less higher retention rates. So I truly believe this is going -- this is one of those transitory things that are happening.

And I think it's catching a lot of organizations by surprise now, the fluidity of employees moving from one economy to another economy, moving to one business to another business. And I truly believe this refocus on the needs of the employees in retirement is a major component of that refocus, is going to be a larger and more dominant theme. And I think this is -- when I talk about this, we're in this transition now, I think many corporations are surprised at this. I think COVID and how we work remotely, people feel -- many people want to work remotely.

They feel differently about their work-life balance. This is all transforming our society in many ways, in a great way, but we're in this transition. And some industries are going to be huge winners in this and some industries are going to be losers of this. But most importantly, I think the common thing, those companies that are working with their employees with purpose, building a deeper, broader connectivity with their employees, they're retaining their employees with greater regularity, and importantly, they're able to attract the best and the brightest.

And we're seeing that more and more. And our conversations about business purpose and stakeholder capitalism, I think it resonates with our corporate clients who have these defined contribution plans, and they're asking us how to create that greater depth of robustness. And then you overlay what we're trying to do related to innovation. I think it really is a compelling story why BlackRock.

Rob Kapito -- *Head, Portfolio Management Group*

And Bill, on your second question, which I think was about fee rates going into the fourth quarter. We generally don't provide a lot of guidance on that. I'll leave that to you guys. But I will say a couple of things on that.

Obviously, you'll see that the spot rate entering the fourth quarter was moderately lower but not a big deal in average assets for the third quarter. So I think we're probably about the same. But I would direct you toward Page 5 of our supplement. I think, obviously, a lot of things go into the fee rate.

And in fact, I'd say that from an organic growth perspective, every month of the third quarter was generally -- was very consistent. So it wasn't like we saw a lot of volatility in terms of our organic growth. But clearly, you do see some differences in the spot rates in terms of markets relative to the average rates. And you'll clearly see there that, as we've talked about in terms of diversion equity beta, we did see an acceleration of in terms of the decline of certain emerging markets as we got to the end of the third quarter.

And I think you'll see that on the supplement, where some of our higher fee markets in Asia, the emerging markets and commodities in particular, are all down roughly -- somewhere around mid- to high single digits, with actually the BlackRock equity index on a spot basis down about 3%. So no question that we did see diversion beta accelerate into the end of the quarter. But again, given some of the other stuff, I think that might have a moderate -- very moderate impact on the fee rate, but I don't think anything significant.

Operator

Thank you. And your last question comes from Robert Lee with KBW. Your line's open.

Larry Fink -- *Chairman and Chief Executive Officer*

Hey, Robert.

https://www.theguardian.com/environment/2021/oct/16/treasury-leak-reveals-rift-between-johnson-and-sunak-over-costs-of-zero-carbon-economy

Treasury leak reveals rift between Johnson and Sunak over costs of zero-carbon economy

With weeks to go before the Cop26 climate summit, documents show PM being warned about the risks of damage to the UK from green investment

Toby Helm & **Fiona Harvey**
Sat 16 Oct 2021 19.12 BST

Confidential documents leaked to the *Observer* reveal an extraordinary rift between Boris Johnson and his chancellor, Rishi Sunak, over the potential economic effects of moving towards a zero-carbon economy, with just weeks to go before the crucial Cop26 climate summit.

As Johnson prepares to position the UK at the head of global efforts to combat climate change and curb greenhouse gas emissions as host of the Glasgow Cop26 meeting, the documents show the Treasury is warning of serious economic damage to the UK economy and future tax rises if the UK overspends on, or misdirects, green investment.

Green experts said the “half-baked” and “one-sided” Treasury net-zero review presented only the costs of action on emissions, rather than the benefits, such as green jobs, lower energy bills and avoiding the disastrous impact of global heating. They said the review could be “weaponised” by climate-change deniers around the world before Cop26, undermining Johnson’s attempts at climate leadership on the global stage.

The internal Treasury documents say that while there may be economic benefits to UK companies from swift and appropriate climate action, there is also a danger that economic activity could move abroad if firms found their costs were increasing by more than those of their overseas competitors.

The leaked papers are understood to have been produced to accompany a slide show given confidentially to key groups outside government in the last month. The documents state: “The investment required to decarbonise the UK economy is uncertain but could help to improve the UK’s relatively low investment levels and increase productivity.

“However, more green investment is likely to attract diminishing returns, reducing the positive impact of ever more investment on GDP. Some green investments could displace other, more productive, investment opportunities. If more productive investments are made earlier in the transition, this risk may be accentuated later in the transition.”

On the risk of additional costs to companies from green initiatives, the documents say: “Climate action in the UK can lead to economic activity moving abroad if it directly leads to costs increasing, and it is more profitable to produce in countries with less stringent climate policies.”

On the fiscal implications, the documents say the cost of moving towards net zero could mean tax rises because of "the erosion of tax revenue from fossil fuel-related activity". They say: "The government may need to consider changes to existing taxes and new sources of revenue throughout the transition in order to deliver net zero sustainably, and consistently with the government's fiscal principles."

Ed Matthew, campaign director at the E3G thinktank, said: "To governments looking to Cop26, this looks unprofessional and embarrassing. The UK is standing in front of the world at Cop26 trying to galvanise ambitious action from every country. If the government has not presented the robust economic case in favour of action, that's going to significantly undermine those attempts."

The Treasury's approach is also starkly at odds with that of business secretary Kwasi Kwarteng and the analysis of the Office for Budget Responsibility (OBR) in a report published in July this year.

On the costs of moving towards net zero, the OBR said in its report: "Between now and 2050 the fiscal costs of getting to net zero in the UK could be significant, but they are not exceptional ... While unmitigated climate change would spell disaster, the net fiscal costs of moving to net zero emissions by 2050 could be comparatively modest."

The Committee on Climate Change, the government's statutory adviser, has also repeatedly said the costs of action are small and diminishing, at less than 1% of GDP by 2050, while the costs of inaction are large and rising.

While there are concerns over how the costs could fall on poorer households, the CCC chief executive Chris Stark has made clear that ministers can choose to distribute the costs and benefits fairly, through the design of green policies.

Whitehall sources said there was a belief that Sunak was keen to position himself as something of a climate-change sceptic in order to boost his popularity with Tory party members, and draw comparisons with Johnson's green enthusiasms. "Rishi clearly sees an interest in showing he is not really down with this green stuff. He wants Boris to own the whole agenda."

A source at the Department for Business, Energy and Industrial Strategy confirmed that the Treasury was "kicking back" against many of the green plans being advanced by No 10 and Kwarteng. "They are not climate change deniers but they are emphasising the short-term risks, rather than long-term needs, which is what we are emphasising."

In contrast to the Treasury's caution, Labour committed at its recent party conference to invest £28bn extra every year until 2030 to secure a "green transition" creating good jobs with decent wages in the process.

The leak comes as the government prepares to publish its long-awaited net zero strategy, and heat and buildings strategy, which will contain policies on cutting emissions and creating green jobs, including a ban on new gas boilers from 2035 and grants for householders to move to green heating.

The government's Cop26 president, former business secretary Alok Sharma, is embarking on a frantic last-ditch round of diplomacy, including with Chinese representatives, amid speculation that President Xi Jinping will not attend the talks. The US and the EU are also talking to key high-emitting countries in the final weeks before Cop26, which opens on 31 October.

The Treasury said: "The government is committed to tackling climate change and the prime minister has set out an ambitious 10-point plan to help us achieve that. The Treasury is playing a crucial role in this effort, by allocating £12bn to fund the plan, setting up the UK infrastructure bank to invest in net zero, and committing to raise £15bn for projects like zero-emissions buses, offshore wind and schemes to decarbonise homes."

Excerpt

SENATE APPROPRIATIONS COMMITTEE, ENERGY AND WATER DEVELOPMENT SUBCOMMITTEE HEARING REVIEW OF THE FY2022 BUDGET SUBMISSION FOR THE DEPARTMENT OF ENERGY

JUNE 23, 2021

SEN. JOHN KENNEDY, R-LA., RANKING MEMBER

WITNESSES:
JENNIFER GRANHOLM, SECRETARY OF ENERGY

KENNEDY: Thank you, Madam Chair. You can probably guess from my opening comments, Madam Secretary, I see the climate as a discrete scientific issue. I think it's a mistake to approach it with too much emotion. Passion is good, but not when it interferes with your judgment.

I've got a couple of - of 30,000 foot question, feet questions. How much money in public and private dollars does the department think it would make - it would take to make the world carbon neutral?

GRANHOLM: I don't have a number for that, but probably a lot.

KENNEDY: Hundreds of trillions of dollars, do you think?

GRANHOLM: It would be a lot, for sure.

KENNEDY: Okay. How much money, in public and private doctors - dollars, does the department think it would take to make the United States carbon neutral?

GRANHOLM: Again, it would be a lot.

KENNEDY: Hundreds of trillions?

GRANHOLM: I don't know about hundreds of trillions, but it would be a lot of money.

KENNEDY: It'd be in the trillions.

GRANHOLM: Yes.

KENNEDY: Mid trillions.

GRANHOLM: I don't know.

KENNEDY: I understand. Here's my question, to make the United States carbon neutral based on the administration's plans, I think it would be fair to say it's going to cause displacement, major displacement. Now I don't use that in a - in a - in a pejorative sense, I think that's just an accurate description. It's going to change our economy dramatically.

Many people are going to gain - many people are going to lose, and that's what I mean by displacement. If we, today, spent these, to be fair, tens of trillions of dollars that I think many members of the administration would like to spend and make the United States of American carbon neutral and nobody else has our - our aggressive - ups our aggressive approach, and they only make modest gains in CO2 emissions, how much is it going to lower the world temperature and how much is - of it - how much - how much are we going to reduce carbon emissions?

GRANHOLM: I want to say that the administration has a really firm commitment to communities to be able to take advantage of the economic opportunity (inaudible)...

KENNEDY: I know, Madam Secretary. Forgive me for interrupting, but we both know now, I'm - I'm - I'm really - want to try to probe your mind here. We both know this is going to cause major displacement. Let's don't kid each other. You're not going to turn coal miners into coders overnight, and you're not going to turn fossil fuel workers into solar experts overnight, and there not as many solar jobs as there are oil and gas, so I don't want to get off into that.

And I'm not trying to be critical of the administration, but I - these are important questions. If we - if we become carbon neutral and we don't get cooperation from China and India, what have we - what have we accomplished?

GRANHOLM: The goal is to get cooperation from China and India.

KENNEDY: I know, but what if they don't?

GRANHOLM: Well...

KENNEDY: What if we go spend these tens of trillions of dollars in President Xi Jinpiang, the people of China are wonderful people, by the way. President Xi (inaudible), we know that. The Communist Party, they're gangsters. What - what if they - what - I mean, they probably built a coal power - a coal powered power plant while we - you and I have been talking. What have we achieved?

GRANHOLM: The administration has a strategy to make sure that all of our - all of the people who have signed onto this Paris agreement meet the goals that they have articulated, and that means working with allies, and that means...

KENNEDY: I - I get it, I get it.

GRANHOLM: ... (inaudible) strategy...

KENNEDY: And that's fair, but I'm asking a very practical question. My son, who I love dearly, has a strategy to have his dad by him a 9/11 Targa Porsche, it's not going to happen. And I'm raising a very legitimate question, I think. If we spend these trillions of dollars and we go through all this displacement and we don't get cooperation from China and India, what - what -what - is the pain worth the gain, and how do we know?

GRANHOLM: I would say we have a strategy to get those countries on board. And if we don't pursue this strategy, what then? Then you have climate disasters that are upon us. California is now - could be on fire again this summer. And if we don't take action, then where are - where is - where are we with respect to the other disasters. So we have to approach our allies --

(CROSSTALK)

KENNEDY: Let me ask you one last question. I get it. I get it. If I -- if you can indulge me, Madam Chair, if we spent all the money that the Biden administration wants to spend, let's take in its current infrastructure bill to reduce CO2 admissions. What percentage of the increase in carbon admissions worldwide, not the United States, is going to be reduced?

GRANHOLM: The -- all of these countries have signed on. All of them have.

KENNEDY: No, I'm talking about -- I know and you're trusting them.

GRANHOLM: Well, no, verified.

KENNEDY: But I believe -- I believe in metrics.

GRANHOLM: Yes.

Electricity Generation*

													Growth rate per annum		Share
Terawatt-hours	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	**2020**	2020	2009-19	2020
Total North America	**5088.1**	**5276.8**	**5293.8**	**5243.5**	**5283.1**	**5314.2**	**5318.4**	**5331.1**	**5287.7**	**5452.5**	**5382.4**	**5243.6**	**-2.8%**	**0.6%**	**19.5%**
Total S. & Cent. America	**1083.0**	**1140.5**	**1181.1**	**1231.4**	**1267.6**	**1287.3**	**1296.6**	**1305.6**	**1306.8**	**1330.9**	**1339.0**	**1282.8**	**-4.5%**	**2.1%**	**4.8%**
Total Europe	**3894.7**	**4065.8**	**4019.4**	**4053.1**	**4022.2**	**3939.2**	**3982.7**	**4021.4**	**4061.3**	**4065.5**	**3992.1**	**3871.3**	**-3.3%**	**0.2%**	**14.4%**
Total CIS	**1226.2**	**1284.0**	**1308.5**	**1330.4**	**1323.7**	**1337.9**	**1340.9**	**1369.3**	**1383.0**	**1416.4**	**1428.8**	**1397.1**	**-2.5%**	**1.5%**	**5.2%**
Total Middle East	**807.9**	**873.7**	**889.7**	**948.6**	**982.4**	**1051.4**	**1109.7**	**1143.7**	**1190.5**	**1207.4**	**1253.6**	**1265.2**	**0.6%**	**4.5%**	**4.7%**
Total Africa	**627.5**	**672.3**	**689.4**	**721.1**	**744.0**	**767.9**	**788.4**	**796.5**	**824.8**	**847.2**	**863.4**	**843.9**	**-2.5%**	**3.2%**	**3.1%**
Total Asia Pacific	**7537.5**	**8257.7**	**8875.1**	**9278.1**	**9812.3**	**10333.7**	**10433.9**	**10947.6**	**11569.8**	**12339.3**	**12741.6**	**12919.3**	**1.1%**	**5.4%**	**48.2%**
Total World	**20264.9**	**21570.7**	**22257.0**	**22806.3**	**23435.2**	**24031.7**	**24270.5**	**24915.2**	**25623.9**	**26659.1**	**27001.0**	**26823.2**	**-0.9%**	**2.9%**	**100.0%**
of which: OECD	10640.3	11062.8	11014.3	11023.7	11015.6	10956.6	11005.0	11082.8	11119.5	11312.8	11168.4	**10880.8**	-2.8%	0.5%	40.6%
Non-OECD	9624.6	10507.9	11242.7	11782.6	12419.7	13075.2	13265.5	13832.4	14504.4	15346.4	15832.5	**15942.4**	0.4%	5.1%	59.4%
European Union #	2847.6	2982.6	2931.3	2932.3	2912.9	2851.1	2899.1	2920.1	2952.4	2937.5	2892.5	**2770.6**	-4.5%	0.2%	10.3%

Source: bp Statistical Review of World Energy 2021

Electricity generation from coal*

													Growth rate per annum		Share
Terawatt-hours	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	**2020**	2020	2009-19	2020
Total North America	**2011.4**	**2114.9**	**1987.7**	**1742.5**	**1814.3**	**1813.7**	**1564.2**	**1442.9**	**1401.0**	**1330.1**	**1131.7**	**898.6**	**-20.8%**	**-5.6%**	**9.5%**
Total S. & Cent. America	**39.3**	**44.3**	**48.6**	**56.9**	**72.7**	**75.1**	**75.1**	**77.9**	**70.0**	**70.4**	**74.4**	**76.4**	**2.5%**	**6.6%**	**0.8%**
Total Europe	**1004.3**	**1016.1**	**1062.4**	**1113.0**	**1085.3**	**1013.2**	**989.7**	**921.7**	**887.8**	**852.4**	**689.5**	**574.8**	**-16.9%**	**-3.7%**	**6.1%**
Total CIS	**225.4**	**235.0**	**237.7**	**239.9**	**235.6**	**230.4**	**227.1**	**236.1**	**246.4**	**255.6**	**254.9**	**229.4**	**-10.2%**	**1.2%**	**2.4%**
Total Middle East	**34.7**	**34.6**	**35.6**	**39.2**	**32.6**	**30.7**	**29.7**	**24.7**	**22.7**	**21.3**	**22.6**	**19.7**	**-13.3%**	**-4.2%**	**0.2%**
Total Africa	**247.7**	**257.3**	**260.0**	**255.5**	**251.4**	**251.9**	**247.0**	**246.9**	**252.1**	**258.8**	**255.7**	**236.0**	**-7.9%**	**0.3%**	**2.5%**
Total Asia Pacific	**4552.6**	**4932.2**	**5444.2**	**5660.7**	**6085.2**	**6337.5**	**6269.6**	**6472.3**	**6836.4**	**7308.1**	**7397.4**	**7386.4**	**-0.4%**	**5.0%**	**78.4%**
Total World	**8115.4**	**8634.5**	**9076.2**	**9107.7**	**9577.1**	**9752.4**	**9402.4**	**9422.4**	**9716.2**	**10096.7**	**9826.2**	**9421.4**	**-4.4%**	**1.9%**	**100.0%**
of which: OECD	3616.9	3733.0	3602.0	3465.2	3534.8	3466.3	3208.1	2993.0	2938.0	2828.7	2450.2	**2067.8**	-15.8%	-3.8%	21.9%
Non-OECD	4498.6	4901.5	5474.2	5642.5	6042.3	6286.1	6194.3	6429.4	6778.2	7268.0	7376.0	**7353.6**	-0.6%	5.1%	78.1%
European Union #	733.3	738.5	761.2	773.3	759.4	722.4	732.5	688.2	669.0	625.7	475.1	**373.4**	-21.6%	-4.2%	4.0%

Source: bp Statistical Review of World Energy 2021

Nuclear: Generation*

													Growth rate per annum		Share
Terawatt-hours	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	**2020**	2020	2009-19	2020
Total North America	**940.9**	**945.3**	**934.8**	**912.8**	**945.1**	**955.3**	**951.8**	**959.4**	**958.8**	**959.3**	**963.9**	**940.4**	**-2.7%**	**0.2%**	**34.8%**
Total S. & Cent. America	**21.1**	**21.7**	**22.1**	**22.4**	**21.7**	**20.9**	**21.8**	**24.1**	**21.8**	**22.5**	**24.6**	**26.0**	**5.4%**	**1.5%**	**1.0%**
Total Europe	**1004.7**	**1032.0**	**1024.2**	**998.4**	**986.5**	**992.7**	**968.3**	**942.2**	**936.1**	**936.1**	**930.0**	**837.4**	**-10.2%**	**-0.8%**	**31.0%**
Total CIS	**166.1**	**172.9**	**175.5**	**179.8**	**174.9**	**183.2**	**198.3**	**199.0**	**205.8**	**206.7**	**211.2**	**218.0**	**3.0%**	**2.4%**	**8.1%**
Total Middle East	**-**	**-**	**0.1**	**1.5**	**4.3**	**4.1**	**3.5**	**6.5**	**7.0**	**6.9**	**6.4**	**8.0**	**23.7%**	**n/a**	**0.3%**
Total Africa	**12.8**	**13.5**	**12.9**	**13.0**	**14.1**	**13.8**	**12.2**	**15.0**	**14.2**	**11.6**	**13.6**	**15.6**	**14.1%**	**0.6%**	**0.6%**
Total Asia Pacific	**553.4**	**582.9**	**483.1**	**342.9**	**344.1**	**371.4**	**419.7**	**467.7**	**493.6**	**553.6**	**646.9**	**654.8**	**0.9%**	**1.6%**	**24.3%**
Total World	**2699.0**	**2768.5**	**2652.7**	**2470.8**	**2490.5**	**2541.4**	**2575.6**	**2613.9**	**2637.2**	**2696.6**	**2796.6**	**2700.1**	**-3.7%**	**0.4%**	**100.0%**
of which: OECD	2258.0	2302.3	2158.3	1962.1	1975.9	1988.5	1974.7	1973.2	1959.8	1966.0	1994.6	**1876.7**	-6.2%	-1.2%	69.5%
Non-OECD	440.9	466.2	494.3	508.7	514.6	552.9	600.9	640.7	677.4	730.6	802.0	**823.4**	2.4%	6.2%	30.5%
European Union #	825.2	854.2	838.0	812.2	806.5	812.8	787.0	768.2	759.7	762.2	765.5	**687.9**	-10.4%	-0.7%	25.5%

Source: bp Statistical Review of World Energy 2021

Renewables: Renewable power generation*

													Growth rate per annum		Share
Terawatt-hours	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	**2020**	2020	2009-19	2020
Total North America	**173.7**	**201.7**	**231.9**	**261.9**	**301.5**	**335.3**	**372.2**	**431.9**	**479.3**	**525.0**	**563.1**	**642.1**	**13.3%**	**11.8%**	**20.4%**
Total S. & Cent. America	**39.1**	**50.9**	**54.0**	**64.1**	**73.8**	**88.6**	**107.1**	**126.4**	**142.6**	**159.4**	**181.4**	**192.9**	**5.7%**	**15.9%**	**6.1%**
Total Europe	**270.3**	**313.6**	**379.5**	**449.9**	**509.2**	**549.7**	**627.5**	**640.2**	**719.7**	**759.9**	**840.0**	**921.0**	**8.9%**	**11.4%**	**29.3%**
Total CIS	**0.6**	**0.6**	**0.7**	**0.6**	**0.7**	**1.0**	**1.4**	**1.8**	**2.1**	**2.5**	**3.8**	**8.1**	**112.2%**	**20.2%**	**0.3%**
Total Middle East	**0.3**	**0.4**	**0.7**	**0.9**	**1.1**	**1.8**	**2.4**	**3.8**	**5.0**	**7.7**	**13.8**	**18.6**	**34.3%**	**44.6%**	**0.6%**
Total Africa	**5.2**	**6.3**	**6.9**	**7.6**	**8.8**	**12.5**	**19.7**	**23.6**	**27.0**	**31.2**	**38.0**	**42.3**	**10.5%**	**21.2%**	**1.3%**
Total Asia Pacific	**146.5**	**187.6**	**234.5**	**282.9**	**350.4**	**425.2**	**504.0**	**623.6**	**804.3**	**992.9**	**1149.2**	**1322.0**	**14.3%**	**22.2%**	**42.0%**
Total World	**635.8**	**761.2**	**908.2**	**1067.9**	**1245.5**	**1414.0**	**1634.4**	**1851.3**	**2180.2**	**2478.6**	**2789.2**	**3147.0**	**12.1%**	**15.3%**	**100.0%**
of which: OECD	491.0	569.3	672.8	778.7	886.7	977.4	1113.9	1197.9	1347.8	1456.6	1599.3	**1788.6**	11.1%	11.9%	56.8%
Non-OECD	144.7	191.9	235.4	289.2	358.8	436.6	520.5	653.4	832.4	1022.0	1189.9	**1358.4**	13.4%	22.7%	43.2%
European Union #	240.8	279.7	336.0	396.7	439.7	466.8	521.3	527.0	583.2	599.9	658.5	**710.4**	7.2%	9.9%	22.6%

Source: bp Statistical Review of World Energy 2021

Electricity generation from gas*

													Growth rate per annum		Share
Terawatt-hours	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	**2020**	2020	2009-19	2020
Total North America	**1172.5**	**1257.1**	**1302.4**	**1533.4**	**1433.6**	**1448.0**	**1688.7**	**1737.8**	**1645.6**	**1849.2**	**1962.4**	**1992.4**	**1.3%**	**5.3%**	**31.8%**
Total S. & Cent. America	**139.8**	**177.0**	**166.7**	**204.1**	**231.3**	**247.9**	**261.5**	**250.5**	**251.6**	**244.6**	**246.6**	**233.5**	**-5.6%**	**5.8%**	**3.7%**
Total Europe	**847.5**	**886.1**	**832.0**	**710.4**	**635.4**	**597.4**	**612.3**	**716.7**	**788.3**	**732.9**	**774.2**	**759.1**	**-2.2%**	**-0.9%**	**12.1%**
Total CIS	**587.2**	**642.1**	**647.7**	**661.7**	**668.5**	**684.2**	**679.9**	**675.3**	**673.9**	**693.8**	**692.3**	**657.9**	**-5.2%**	**1.7%**	**10.5%**
Total Middle East	**469.5**	**529.4**	**504.5**	**534.4**	**548.4**	**634.7**	**692.6**	**750.5**	**815.4**	**799.2**	**813.7**	**836.1**	**2.5%**	**5.7%**	**13.3%**
Total Africa	**189.9**	**216.7**	**234.6**	**258.8**	**265.4**	**273.7**	**289.5**	**303.5**	**327.3**	**335.7**	**337.5**	**332.2**	**-1.8%**	**5.9%**	**5.3%**
Total Asia Pacific	**1045.4**	**1164.2**	**1240.7**	**1319.4**	**1317.4**	**1367.7**	**1378.5**	**1404.5**	**1439.6**	**1478.7**	**1497.1**	**1456.9**	**-3.0%**	**3.7%**	**23.2%**
Total World	**4451.8**	**4872.6**	**4928.6**	**5222.0**	**5099.9**	**5253.6**	**5603.1**	**5838.8**	**5941.7**	**6134.1**	**6323.8**	**6268.1**	**-1.2%**	**3.6%**	**100.0%**
of which: OECD	2476.8	2646.3	2692.6	2863.8	2714.3	2710.7	2928.6	3073.0	3067.5	3229.0	3358.6	**3360.0**	-0.2%	3.1%	53.6%
Non-OECD	1975.1	2226.3	2236.0	2358.2	2385.6	2542.9	2674.5	2765.8	2874.2	2905.1	2965.2	**2908.1**	-2.2%	4.1%	46.4%
European Union #	566.6	589.2	554.8	482.6	414.3	357.2	396.6	467.4	526.2	491.2	566.7	**552.9**	-2.7%	♦	8.8%

Source: bp Statistical Review of World Energy 2021 https://www.railfreight.com/railfreight/2021/10/13/freightliner-takes-down-electric-locs-due-to-high-electricity-prices/?gdpr=accept

Freightliner takes down electric locos due to high electricity prices

Published on 13-10-2021 at 06:00

The shocking rise in electricity prices has sparked some rail freight operators into a startling scenario. Electric locomotives are to be stopped and operators will resort to diesel traction instead. This would pose difficult questions for the UK and devolved governments, who lay claim to a diversified energy generation policy. It would also drive a freight train straight through decarbonisation plans.

The UK operation of the global Genesee and Wyoming corporation – Freightliner – has been first to react. "As a result of soaring prices on the UK's wholesale electricity market, the price Network Rail charges us to operate electric train services has increased by more than 210 per cent between September and October", says their statement. "This unprecedented rise in electricity charges has resulted in a sharp increase in the cost of operating electric freight services. As a result, Freightliner has taken the difficult decision to temporarily replace electric freight services with diesel-hauled services, in order to maintain a cost-effective option for transporting vital goods and supplies across the UK."

Electricity prices up 210 per cent

The UK operation of the global Genesee and Wyoming corporation – Freightliner – has been first to react. "As a result of soaring prices on the UK's wholesale electricity market, the price Network Rail charges us to operate electric train services has increased by more than 210 per cent between September and October", says their statement. "This unprecedented rise in electricity charges has resulted in a sharp increase in the cost of operating electric freight services. As a result, Freightliner has taken the difficult decision to temporarily replace electric freight services with diesel-hauled services, in order to maintain a cost-effective option for transporting vital goods and supplies across the UK."

Over the Rainbow or over ab out, for now? Freightliner has grounded its fleet of class 90 electric locomotives due to steeply rising energy costs.

Freightliner: removing electric locs contrary to strategy

As the largest UK freight operator of electric locomotives, Freightliner has sought to deploy more electric traction on routes to further reduce carbon emissions and improve the already green credentials of rail freight. Rail freight, say Freightliner, in a statement echoed by the industry at large, is inherently a carbon efficient mode of transport. Even with a diesel locomotive, each tonne of freight moved by rail instead of road reduces emissions by 76 per cent.

Electric-hauled freight services can further reduce emissions by up to 99 per cent. "Removing electric locomotives in the near term from our trains is contrary to our preferred strategy and at odds with the UK's decarbonisation objectives; however, such high energy costs leave us no choice", they say. "We remain hopeful that Network Rail and Government might find a solution that avoids pricing electric freight traction off the network and enables us to reinstate electric services."

What has gone wrong?

The scenario of using fossil fuel motive power because the base energy is cheaper has met with derision from environmentalists. It is not something that has been contemplated for over a decade. Now, with electricity prices seemingly going ever higher, operators are rethinking their traction plans. Stabling electric locomotives would not only put a significant part of the national fleet out of action, it would have direct impacts on the timetable, and ability of rail freight to deliver. Some commentators are already saying this is a gun to the head of the government.

Worldwide, gas prices have been rising, as demand recovers from the pandemic. This has meant higher prices on the global spot markets. The UK position has been made more acute for a number of reasons. First, with coal taken out of the energy generation chain, the remaining fleet of power installations has been running at close to capacity. Diversified supply – from renewables and nuclear, and operations like the Drax biomass plant – are all at maximum output.

Drax power station in North Yorkshire is biomass powered. Ironically, the electricity it produces may not power environmentally-friendly freight trains any time soon (image Drax)

The only significant resource left is gas-powered generation, of which the UK has enough to keep the national grid supplied. However, gas storage is at a premium in the UK, and poor hedging by some companies (buying ahead of demand at a favourable price) has left the UK with no option but to buy at today's inflated costs. That has caused all energy-intensive industries to look long and hard at their consumption figures and, in some cases, contemplate shutting down.

23 locos shunted off the rails

“Such a significant increase in the price of electricity cannot be absorbed by us or our customers at a time of wider supply chain challenges for the UK economy”, says Eddie Aston, the chief executive officer of Genesee and Wyoming UK/Europe operations, which includes Freightliner. “We regret that we have taken the decision to temporarily withdraw our electric locomotives from service. However, nobody benefits when such sharp spike in charges leads to low-carbon, electric locomotives being parked-up in yards. We will continue to work with Network Rail and with Government to find a resolution that, in the short term, enables us to reinstate electric services, and, in the longer term, aligns charges and incentives with Government objectives. Such alignment will enable further investments in low-carbon traction, deliver greater modal shift from road to rail and support the country's journey to net zero”.

Freightliner operates 23 electric locomotives, with the recently re-engineered former express passenger class 90 locomotives taking pride of place. Along with older class 86 models, they represent around ten per cent of the company's fleet. Most other operators have yet to make their plans known. DB cargo, however, already say they will not be altering the mix of their traction fleet at present.

Red face for Boris, anger from unions

Unions have been quick to criticise the situation. The RMT has warned that the electricity price hike threatens to “destroy rail freight and jack up dirty diesel use.” It is huge embarrassment for the UK government with the climate change COP26 conference in Glasgow just one month away. “As COP26 approaches the Government have to step in to stop this carnage on our railways”, said general secretary of RMT, Mick Lynch. “With the road haulage industry already in turmoil, and with the threat of empty shelves this Christmas, we should be encouraging the use of rail freight not battering it into submission with electricity charges that will add millions of pounds to rail freight companies' bills, with one operator reporting an eight million pound [9 million euro] increase in costs.


Shocked and looking for a spark of inspiration. British prime minister Boris Johnson has been heavily criticised for the government response to the energy crisis (Flickr)

The UK supply chain is already under severe strain. Road haulage companies have struggled to find drivers, and shops have had gaps in their shelves. During the pandemic, the rail fright industry was repeatedly hailed by the government as a saviour, for keeping food and essential supplies distributed. Coming on the back of the pandemic, the lockdown, and the petrol and diesel supply issues, the UK government has been roundly criticised for their handling of this latest crisis. If that really is the case, then not just the economy, but the environment stands to suffer too, giving Boris Johnson a red face in Glasgow next month.

Tags: class 90, DB Cargo UK, drax, Electricity, Electricity supply, Freightliner, RMT

Making Fuel From Straw Is About to Become a Thing in Europe
2021-10-15 11:19:54.752 GMT

By Rachel Graham
(Bloomberg) -- Turning bales of straw into ethanol is about to become a highly profitable venture in Europe, according to a firm that just opened a production site in the continent.
Clariant AG, a Swiss chemicals maker, just opened a facility in Romania to make so-called advanced biofuels, which use agricultural waste or non-edible crops to make fuels that can be blended into gasoline and diesel. That's environmentally better than so-called first-generation ethanol currently on the market, which is made from foodstuffs like sugar or corn.
The carbon savings from the new approach will make ethanol that's more profitable compared with existing processes, Clariant Chief Executive Officer Conrad Keijzer said on a conference call.
"We expect double the price to first generation," he said. That's "simply because it's legislated," he said.
Clariant built the plant mainly to promote its technology, which it now wants to license to other companies.
The European Union has set a target that at least 0.2% of all transport fuels should be made from advanced biofuels next year, rising to 2.2% in 2030.
Clariant's technology could also be used in chemicals and aviation. "This is a prime example of a circular economy solution," Keijzer said.

To contact the reporter on this story:
Rachel Graham in London at rgraham13@bloomberg.net
To contact the editors responsible for this story:
Alaric Nightingale at anightingal1@bloomberg.net
Stephen Voss

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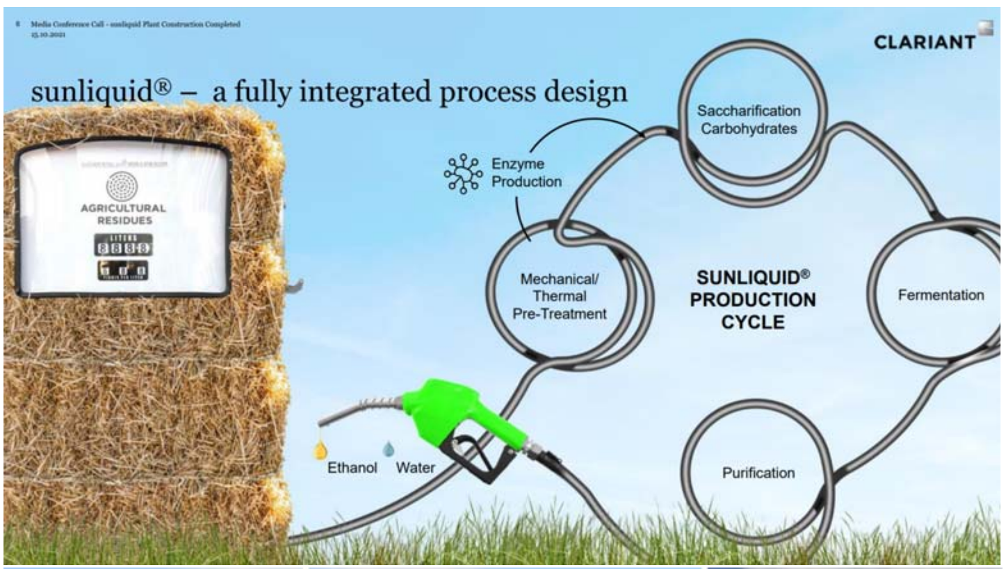


Source: Clariant AG

Recommendations on climate change and health:

1

Commit to a healthy recovery.

Commit to a healthy, green, and just recovery from COVID-19.

2

Our health is not negotiable.

Place health and social justice at the heart of the UN climate talks.

3

Harness the health benefits of climate action.

Prioritise those climate interventions with the largest health-, social- and economic gains.

4

Build health resilience to climate risks.

Build climate-resilient and environmentally sustainable health systems and facilities, and support health adaptation and resilience across sectors.

5

Create energy systems that protect and improve climate and health.

Guide a just and inclusive transition to renewable energy to save lives from air pollution, particularly from coal combustion. End energy poverty in households and health care facilities.

6

Reimagine urban environments, transport, and mobility.

Promote sustainable, healthy urban design and transport systems, with improved land-use, access to green and blue public space, and priority for walking, cycling and public transport.

7

Protect and restore nature as the foundation of our health.

Protect and restore natural systems, the foundations for healthy lives, sustainable food systems and livelihoods.

8

Promote healthy, sustainable, and resilient food systems.

Promote sustainable and resilient food production and more affordable, nutritious diets that deliver on both climate and health outcomes.

9

Finance a healthier, fairer, and greener future to save lives.

Transition towards a wellbeing economy.

10

Listen to the health community and prescribe urgent climate action.

Mobilise and support the health community on climate action.

The COVID-19 pandemic has highlighted the close relationship between the health of people and the health of the planet, and has further exacerbated existing social injustices and vulnerabilities in our communities and our health systems. The pandemic has also provided an opportunity for building forward better, greener and more equitably *(34)*.

The next few months and years provide a crucial window to align climate change and health goals. Governments can commit to a healthy and green recovery from COVID-19 by following an evidence-based path to a zero carbon, resilient, and inclusive global economy. This is in line with the WHO Manifesto Prescriptions and "Actionables", which offer governments a list of priority actions to achieve a green and healthy recovery from COVID-19 *(35)*.

Action Points

Commit to a healthy recovery.

1. **Align climate and health goals**. Align COVID-19 recovery efforts with the Paris Agreement goals and the WHO Manifesto for a healthy and green recovery.
2. **Support a fossil-free recovery.** Commit to 100% green stimulus spending and an end to all fossil fuel subsidies, while also ensuring energy access for all.
3. **Prevent and prepare for the next pandemic.** Improve the global capacity for pandemic prevention, preparedness, and response.
4. **Include health in all policies**. Strengthen and support implementation of the Health-in-All-Policies approach at the national and subnational level.
5. **Commit to vaccine equity**. Commit to vaccine equity and address the inequalities that lie at the root of the current climate and health crises.

1) Align climate and health goals.

Scientists, leaders, and the wider public have a growing understanding that unless everyone is safe, no one is safe when it comes to the multiple crises the world is grappling with. Short-term response and long-term recovery measures and economic stimulus packages therefore need to tackle these crises in tandem. The health community has repeatedly urged governments to align their COVID-19 recovery efforts with the Paris Agreement goals and the WHO Manifesto for a healthy and green recovery *(36)*.

Recovery measures that align climate and health goals are driven by science, prioritise those interventions that bring health, social, cultural and environmental gains, and avoid locking in economic development patterns that will do permanent and escalating damage to the ecological systems that sustain all human health and livelihoods. Examples include setting measures that help avoid a rebound to pre-pandemic air pollution levels, creating more people-centred cities through improved active transport infrastructure *(37)*, and ensuring the COVID-19 response strengthens health systems while reducing health inequities and other health risks at the same time *(38)*.

2) Support a fossil-free recovery.

The burning of fossil fuels is killing us; causing millions of premature deaths every year through air pollutants, costing the global economy billions of dollars annually, and fuelling the climate crisis *(6)*. Governments and the private sector can support a green and healthy recovery from COVID-19 by: reforming energy subsidies so no public money goes to fossil fuel production; raising money from fossil fuel subsidy reform and taxes to be re-invested in a green recovery; ensuring that public money committed to energy-producing and -consuming activities goes to clean energy sources; while incentivising investments in clean energy and ensuring that no one is left behind in the energy transition *(39,40)*.

https://www.latimes.com/california/story/2021-10-09/california-moves-toward-ban-on-gas-lawnmowers-and-leaf-blowers

California moves toward ban on gas lawn mowers and leaf blowers

California will outlaw the sale of new gas-powered lawn mowers, leaf blowers and chain saws as early as 2024 under a new law signed by Gov. Gavin Newsom.

BY PHIL WILLONSTAFF WRITER

OCT. 9, 2021 6:32 PM PT

SACRAMENTO —

California will outlaw the sale of new gas-powered lawn mowers, leaf blowers and chain saws as early as 2024 under a new law signed by Gov. Gavin Newsom on Saturday.

The law requires all newly sold small-motor equipment primarily used for landscaping to be zero-emission — essentially to be battery-operated or plug-in — by that target date or as soon as the California Air Resources Board determined it is feasible. New portable gas-powered generators also must be zero-emission by 2028, which also could be delayed at the discretion of the state agency.

Machinery with so-called small off-road engines also includes chain saws, weed trimmers and golf carts, all of which create as much smog-causing pollution in California as light-duty passenger cars, and reducing those emissions is pivotal to improving air quality and combating climate change, proponents of the law said.

“It’s amazing how people react when they learn how much this equipment pollutes, and how much smog-forming and climate-changing emissions that small off-road engine equipment creates,” said Assemblyman Marc Berman (D-Menlo Park), author of the legislation. “This is a pretty modest approach to trying to limit the massive amounts of pollution that this equipment emits, not to mention the health impact on the workers who are using it constantly.”

Berman said the state has set aside $30 million to help professional landscapers and gardeners make the transition from gas-powered equipment to zero-emission equipment, but an industry representative said that’s woefully inadequate for the estimated 50,000 small businesses that will be affected by the law.

Andrew Bray, vice president of government relations for the National Assn. of Landscape Professionals, said the zero-emission commercial-grade equipment landscapers use is also prohibitively expensive and less efficient than the existing gas-powered lawn mowers, leaf blowers and other small machinery. For example, a gas-powered commercial riding lawn mower costs $7,000 to $11,000, but its zero-emission equivalent costs more than twice that amount, he said.

Another major expense will be batteries. Bray said a three-person landscaping crew will need to carry 30 to 40 fully charged batteries to power its equipment during a full day’s work.

“These companies are going to have to completely retrofit their entire workshops to be able to handle this massive change in voltage so they’re going to be charged every day,” Bray said.

Berman said the move to zero-emission landscaping equipment already is underway, especially among the vast majority of property owners who can mow their lawns and trim hedges on a single battery charge. Cities and universities have also started to make the transition, he said. Berman also emphasized that gas-powered equipment purchased before the deadlines can still be used, by both property owners and professional landscapers.

The legislation was opposed by Republican lawmakers, as well as some Democrats, who expressed concern about residents in rural areas — especially when it comes to the state requirement that portable generators be zero-emission.

In recent years, California has had widespread blackouts in the peak of the wildfire season when high winds sweep through the state, mostly because utilities are trying to prevent a downed power line from starting a blaze. Because of that, Sen. Brian Dahle (R-Bieber) said banning gas-powered generators makes no sense.

“This Legislature hates fuel, which is very sustainable. It’s easy to access. And when the power is off, you can still use it. You can still run a generator to keep your freezer going, to keep your medical devices going. But when your battery’s dead and there’s no power on, you have nothing,” Dahle said.

Berman said those concerns are being taken into account, and the law specifically requires the California Air Resources Board to adjust the restrictions on generators based on their “expected availability” of that equipment on the commercial and retail market.

The new law applies to any engine that produces less than 25 gross horsepower, including lawn mowers, weed trimmers, chain saws, golf carts, specialty vehicles, generators and pumps. It does not apply to on-road motor vehicles, off-road motorcycles, all-terrain vehicles, boats, snowmobiles or model airplanes, cars or boats.

The California Air Resources Board has been drafting regulations mandating that small engines covered in the new law be zero-emission, and the board could enact those requirements before year's end.

The agency began working on the regulations after Newsom issued an executive order in September 2020 that required the state to "transition to 100 percent zero-emission off-road vehicles and equipment by 2035 where feasible."

In that same order, Newsom required all new cars sold to be zero-emission vehicles by 2035 and threw his support behind a ban on the controversial use of hydraulic fracturing by oil companies.

https://www.fao.org/worldfoodsituation/foodpricesindex/en/

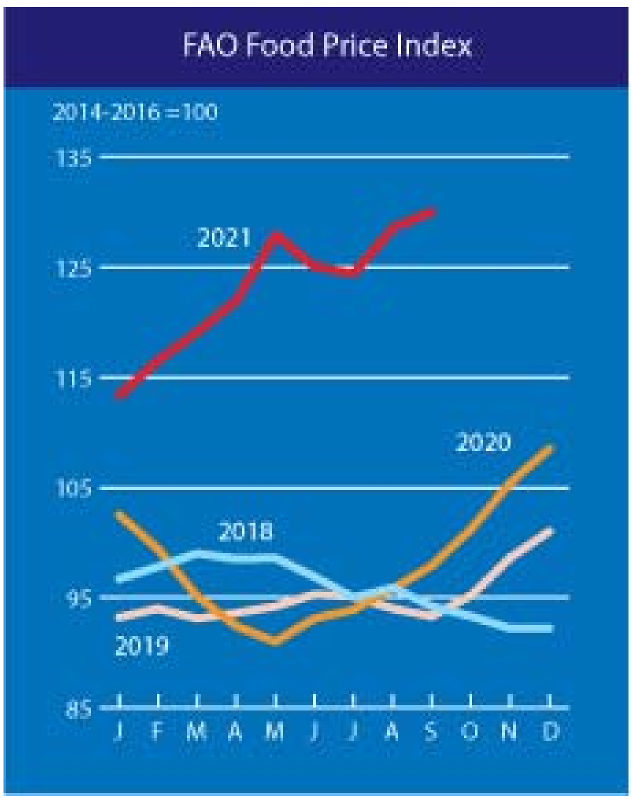
FAO Food Price Index

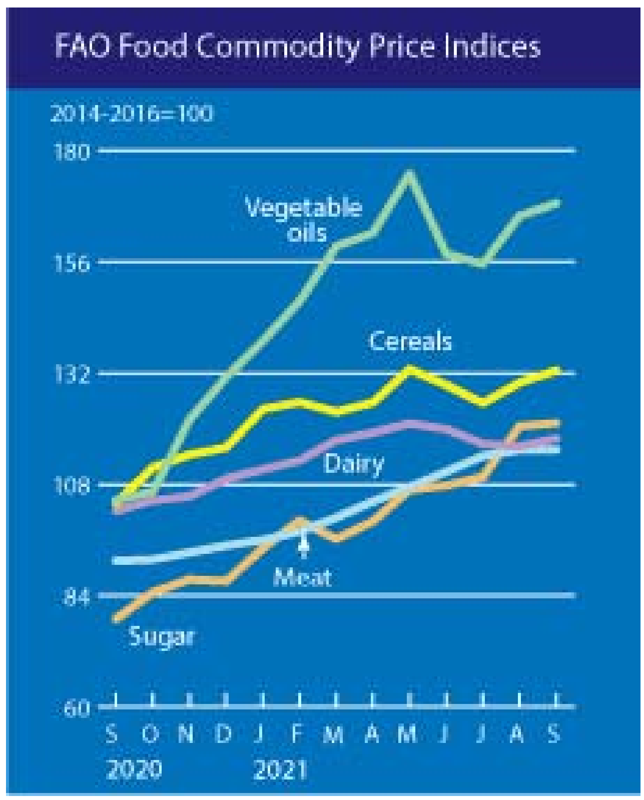
The FAO Food Price Index (FFPI) is a measure of the monthly change in international prices of a basket of food commodities. It consists of the average of five commodity group price indices weighted by the average export shares of each of the groups over 2014-2016. A feature article published in the June 2020 edition of the Food Outlook presents the revision of the base period for the calculation of the FFPI and the expansion of its price coverage, to be introduced from July 2020. A November 2013 article contains technical background on the previous construction of the FFPI.

Monthly release dates for 2021: 7 January, 4 February, 4 March, 8 April, 6 May, 3 June, 8 July, 5 August, 2 September, 7 October, 4 November, 2 December.

The FAO Food Price Index rose further in September

Release date: 07/10/2021





» The FAO Food Price Index (FFPI) averaged 130.0 points in September 2021, up 1.5 points (1.2 percent) from August and 32.1 points (32.8 percent) from the same month last year. The latest rise of the FFPI was largely driven by higher prices of most cereals and vegetable oils. Dairy and sugar prices were also firmer, while the meat price sub-index remained stable.

» The FAO Cereal Price Index averaged 132.5 points in September, up 2.6 points (2.0 percent) from August and 28.5 points (27.3 percent) above its level of September 2020. Among the major cereals, world wheat prices increased the most in September, up almost 4 percent month-on-month and as much as 41 percent year-on-year. Tightening export availabilities amidst strong world demand continued pushing up international wheat prices. Rice prices rose in September to stand above the multi-year lows touched in August 2021, sustained by a mild improvement in trading activities. International barley prices also increased in September, by 2.6 percent, mostly driven by strong demand, downgraded production prospects in the Russian Federation and gains in other markets. By contrast, world maize prices remained generally stable, up only 0.3 percent from August, as upward pressure from hurricane-related port disruptions in the US was countered by improved global crop prospects and the start of harvests in the US and Ukraine. Nonetheless, maize prices remained elevated at nearly 38 percent above their levels of September 2020.

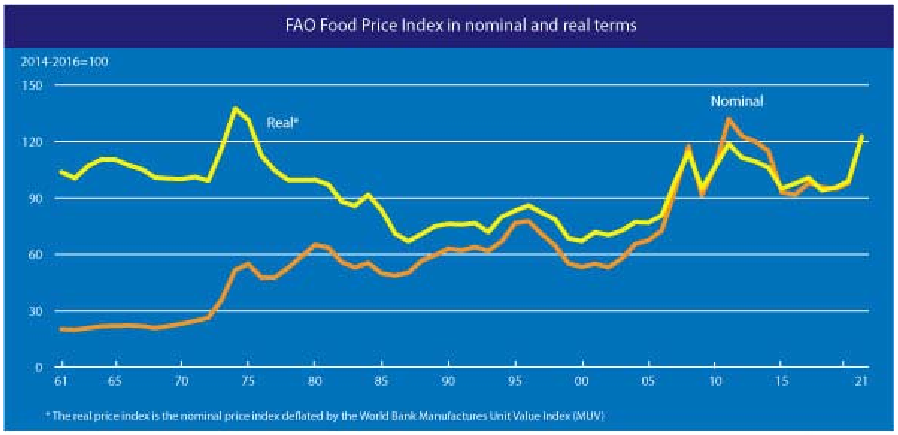
» The FAO Vegetable Oil Price Index averaged 168.6 points in September, up 2.9 points (or 1.7 percent) month-on-month and about 60 percent above its year-earlier level. The increase was mainly driven by higher palm and rapeseed oil values, whereas quotations for soy and sunflower oils declined. International palm oil prices rose for a third consecutive month reaching ten-year highs, underpinned by robust global import demand that coincided with concerns over below-potential production in Malaysia due to persisting migrant labour shortages. Global rapeseed oil prices also appreciated markedly, fueled by protracted global supply tightness. By contrast, world soy and sunflower oil prices declined in September on, respectively, uncertainties regarding soyoil uptake by the biodiesel industry and prospects of ample global supplies in the 2021/22 season.

» The FAO Dairy Price Index averaged 117.9 points in September, up 1.7 points (1.5 percent) from August and exceeding by 15.6 points (15.2 percent) its value in the corresponding month last year. In September, international quotations for all dairy products represented in the index rose, with skim milk powder (SMP) and butter rising sharply, underpinned by solid global import demand amid limited export availabilities, especially from Europe on the back of low inventories and seasonally declining milk production. Limited milk production at this early stage of the new season in Oceania, coupled with low stocks, also lifted world butter and SMP prices. Meanwhile, whole milk powder (WMP) and cheese prices rose moderately, owing to a combination of constrained production, low inventories and steady internal demand in Europe.

» The FAO Meat Price Index* averaged 115.5 points in September, virtually unchanged from its revised value for August and 24.1 points (26.3 percent) above its value in the corresponding month a year ago. In September, international quotations for ovine meat increased further, driven by firm global demand while exportable supplies remained tight. The bovine meat price rally also continued unabated, as limited availability of cattle for slaughter in Oceania and South America weighed on global supplies. By contrast, after rising consecutively for nine months, quotations for poultry meat slipped on increased global supply volumes, while world pig meat prices also declined due to lower import demand from China and depressed internal demand, especially in Europe.

» The FAO Sugar Price Index averaged 121.2 points in September, up 0.6 points (0.5 percent) from August and 42.2 points (53.5 percent) above the level registered in the corresponding month last year. Concerns over a reduced output in Brazil, the world's largest sugar exporter, due to prolonged dry weather conditions and frosts, continued to underpin the increase in world sugar prices. In addition, higher ethanol prices encouraged a greater use of sugarcane for ethanol production in Brazil. However, the upward pressure on prices was limited by a slowdown in global import demand for sugar and good production prospects in key exporters, such as India and Thailand.

* Unlike for other commodity groups, most prices utilized in the calculation of the FAO Meat Price Index are not available when the FAO Food Price Index is computed and published; therefore, the value of the Meat Price Index for the most recent months is derived from a mixture of projected and observed prices. This can, at times, require significant revisions in the final value of the FAO Meat Price Index which could in turn influence the value of the FAO Food Price Index.



FAO food price index

		Food Price Index [1]	Meat [2]	Dairy [3]	Cereals [4]	Vegetables Oils [5]	Sugar [6]
2003		**57.8**	**58.3**	**54.5**	**59.4**	**62.6**	43.9
2004		**65.6**	**67.6**	**69.8**	**64.0**	**69.6**	44.3
2005		**67.4**	**71.8**	**77.2**	**60.8**	**64.4**	61.2
2006		**72.6**	**70.5**	**73.1**	**71.2**	**70.5**	91.4
2007		**94.3**	**76.9**	**122.4**	**100.9**	**107.3**	62.4
2008		**117.5**	**90.2**	**132.3**	**137.6**	**141.1**	79.2
2009		**91.7**	**81.2**	**91.4**	**97.2**	**94.4**	112.2
2010		**106.7**	**91.0**	**111.9**	**107.5**	**122.0**	131.7
2011		**131.9**	**105.3**	**129.9**	**142.2**	**156.5**	160.9
2012		**122.8**	**105.0**	**111.7**	**137.4**	**138.3**	133.3
2013		**120.1**	**106.2**	**140.9**	**129.1**	**119.5**	109.5
2014		**115.0**	**112.2**	**130.2**	**115.8**	**110.6**	105.2
2015		**93.0**	**96.7**	**87.1**	**95.9**	**89.9**	83.2
2016		**91.9**	**91.0**	**82.6**	**88.3**	**99.4**	111.6
2017		**98.0**	**97.7**	**108.0**	**91.0**	**101.9**	99.1
2018		**95.8**	**94.9**	**107.3**	**100.6**	**87.8**	77.4
2019		**95.0**	**100.0**	**102.8**	**96.4**	**83.2**	78.6
2020		**98.0**	**95.5**	**101.8**	**102.7**	**99.4**	79.5
2020	September	**97.9**	91.5	102.3	104.0	104.6	79.0
	October	**101.2**	91.8	104.5	111.6	106.5	84.7
	November	**105.5**	93.3	105.4	114.4	121.9	87.5
	December	**108.5**	94.8	109.2	115.9	131.2	87.1
2021	January	**113.3**	96.0	111.2	124.2	138.9	94.2
	February	**116.5**	97.8	113.1	125.7	147.5	100.2
	March	**119.1**	100.8	117.5	123.6	159.3	96.2
	April	**121.9**	104.3	119.1	125.6	162.2	100.0
	May	**127.9**	107.4	121.1	132.8	174.9	106.8
	June	**125.0**	110.7	119.9	129.4	157.7	107.7
	July	**124.4**	114.1	116.7	125.5	155.5	109.6
	August	**128.5**	115.4	116.2	129.9	165.9	120.5
	September	**130.0**	115.5	117.9	132.5	168.6	121.2

1 Food Price Index: Consists of the average of 5 commodity group price indices mentioned above, weighted with the average export shares of each of the groups for 2014-2016: in total 95 price quotations considered by FAO commodity specialists as representing the international prices of the food commodities are included in the overall index. Each sub-index is a weighted average of the price relatives of the commodities included in the group, with the base period price consisting of the averages for the years 2014-2016.

2 Meat Price Index: Based on 35 average export unit values/market prices of four meat types (bovine, pig, poultry and ovine) from 10 representative markets. Within each meat type, export unit values/prices are weighted by the trade shares of their respective markets, while the meat types are weighted by their average global export trade shares for 2014-2016. Quotations for the two most recent months may consist of estimates and be subject to revision.

3 Dairy Price Index: Computed using 8 price quotations of four dairy products (butter, cheese, SMP and WMP) from two representative markets. Within each dairy product, prices are weighted by the trade shares of their respective markets, while the dairy products are weighted by their average export shares for 2014-2016.

4 Cereals Price Index: Compiled using the International Grains Council (IGC) wheat price index (an average of 10 different wheat price quotations), the IGC maize price index (an average of 4 different maize price quotations), the IGC barley price index (an average of 5 different barley price quotations), 1 sorghum export quotation and the FAO All Rice Price Index. The FAO All Rice Price Index is based on 21 rice export quotations, combined into four groups consisting of Indica, Aromatic, Japonica and Glutinous rice varieties. Within each varietal group, a simple average of the relative prices of appropriate quotations is calculated; then the average relative prices of each of the four rice varieties are combined by weighting them with their (fixed) trade shares for 2014-2016. The Cereal Price Index combines the relative prices of sorghum, the IGC wheat, maize and barley price indices (re-based to 2014-2016) and the FAO All Rice Price Index by weighing each commodity with its average export trade share for 2014-2016.

5 Vegetable Oil Price Index: Consists of an average of 10 different oils weighted with average export trade shares of each oil product for 2014-2016.

6 Sugar Price Index: Index form of the International Sugar Agreement prices with 2014-2016 as base.

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EXECUTIVE SUMMARY

More than a year and a half into the COVID-19 outbreak, the recent spread of the highly transmissible delta variant in the United States has extended problems for many households over the past few months. Even though many experts predicted the COVID-19 outbreak would already be subsiding, the delta variant is continuing to cause problems in the lives of most households across the nation, including severe financial and health impacts on a share of households who are in crisis.

This report examines the most serious problems facing U.S. households during the delta variant outbreak, with an aim to identify vulnerable populations in urgent need of government help or charitable aid. NPR, The Robert Wood Johnson Foundation, and the Harvard T.H. Chan School of Public Health conducted a survey August 2 – September 7, 2021, to examine the most serious problems facing households across America in the past few months when it comes to their finances, healthcare, racial/ethnic discrimination, education, caregiving, work, and well-being.

Despite billions of dollars appropriated by federal and state governments during the COVID-19 outbreak to protect vulnerable Americans, as well as recent reports that the poverty rate has declined, results from this survey show that a substantial share of households across the U.S. have not been adequately protected from financial problems. Many report serious impacts across different areas of their lives in the past few months alone. Of note, this poll measured experiences just before federal pandemic unemployment benefits ended and at the time housing eviction protections expired, so estimates do not include the potential impact of these events.

These findings raise important concerns about the limited financial resources of many U.S. households to weather the economic effects of the delta variant outbreak, as a significant share have lost their household savings during the COVID-19 outbreak and are facing major problems paying for basic costs of living, including rent, utilities, and medical care.

Main findings from this report include:

- Thirty-eight percent (38%) of households across the nation report facing serious financial problems in the past few months.
- There is a sharp income divide in serious financial problems, as 59% of those with annual incomes below $50,000 report facing serious financial problems in the past few months, compared with 18% of households with annual incomes of $50,000 or more.
- These serious financial problems are cited despite 67% of households reporting that in the past few months, they have received financial assistance from the government.
- Another significant problem for many U.S. households is losing their savings during the COVID-19 outbreak. Nineteen percent (19%) of U.S. households report losing all of their savings during the COVID-19 outbreak and not currently having any savings to fall back on.
- At the time the Centers for Disease Control and Prevention's (CDC) eviction ban expired, 27% of renters nationally reported serious problems paying their rent in the past few months.

- When it comes to their children's education, 69% of households with children in K-12 last school year say their children fell behind in their learning because of the COVID-19 outbreak, including 36% of all households with children in K-12 reporting their children fell behind *a lot.*

- Thinking about the upcoming school year, 70% of households whose children fell behind last school year believe it will be difficult for children in their household to catch up on education losses from last school year.

- One in five households with children (20%) report they have experienced serious problems getting childcare in the past few months when adults needed to work.

- When it comes to internet connectivity, despite significant efforts since the start of the COVID-19 outbreak to expand Americans' internet access, 23% of households with children still report either having serious problems with their internet connection to do schoolwork or their jobs, or that they do not have a high-speed internet connection at home.

- In a period when the Federal Bureau of Investigation (FBI) has found that reported hate crimes in the U.S. have increased, an examination of different racial and ethnic minority households' personal experiences in the past few months shows stark fears of being threatened or attacked. One in four Asian households in the U.S. (25%) report fearing someone might threaten or physically attack them because of their race/ethnicity in the past few months, while 22% of Native American households, 21% of Black households, 8% of Latino households, and 7% of white households also report this.

- In healthcare, 18% of households report anyone in their household has been unable to get medical care for a serious problem in the past few months when they needed it, with 76% of those unable to get care reporting negative health consequences as a result. Among households unable to get care when they needed it, 78% report having health insurance, while 22% report not having health insurance.

- Forty-two percent of households (42%) report using telehealth in the past few months, with wide reported satisfaction (82% satisfied). Despite this, 64% of households using telehealth say they would have preferred an in-person visit over telehealth in their last visit.

- Half of households (50%) report anyone has experienced serious problems with depression, anxiety, stress, or serious problems sleeping in the past few months.

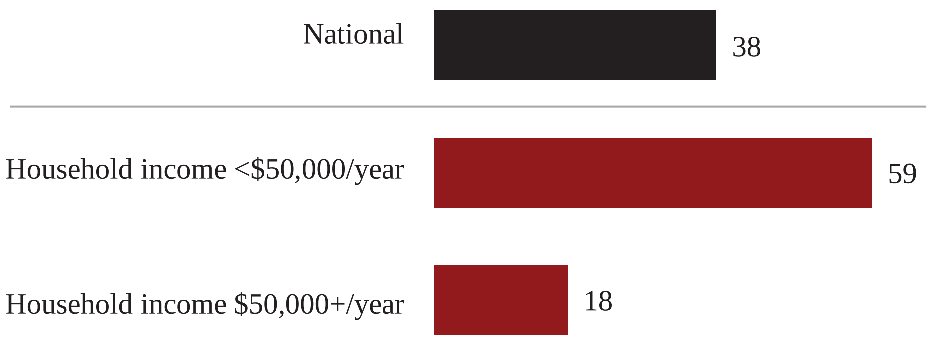
- Among employed adults, 24% report having a worse job situation now compared to before the COVID-19 outbreak began, while 21% report having a better job situation, and 55% rate their job situation as about the same as it was before the COVID-19 outbreak.

I. Serious Financial Problems

38% of households report facing serious financial problems in the past few months

In the past few months alone, 38% of U.S. households report facing serious financial problems. This includes 59% of households with annual incomes below $50,000 reporting serious financial problems, compared with 18% of households with annual incomes of $50,000 or more (see Figure 1). These problems are cited despite 67% of households reporting that in the past few months, they have received financial assistance from the government.

Figure 1. Serious Financial Problems among U.S. Households in the Past Few Months (in Percent)

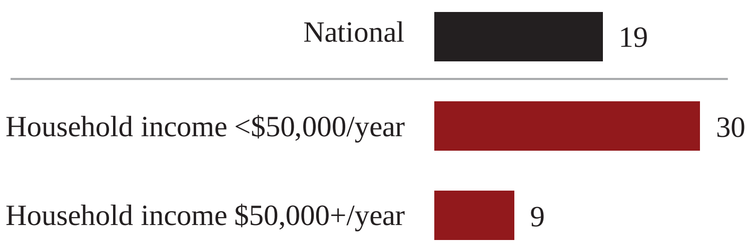


NPR/Robert Wood Johnson Foundation/Harvard T.H. Chan School of Public Health, *Household Experiences in America During the Delta Variant Outbreak*, 8/2/21 – 9/7/21. N=3,616 U.S. adults ages 18+. Income defined as reported 2020 household income. *Q7. In the past few months, have you or anyone living in your household been having serious problems… a) paying the mortgage/rent, b) paying for utilities, c) making car payments, d) affording medical care, e) paying credit cards/loans/other debt, f) affording food, g) other serious financial problems?*

19% of households lost all savings during the COVID-19 outbreak and have no savings to fall back on

Another significant problem for many U.S. households is losing their savings during the COVID-19 outbreak (see Figure 2). Nineteen percent (19%) of U.S. households report losing all of their savings during the COVID-19 outbreak and not currently having any savings to fall back on. This includes 30% of households with annual incomes below $50,000, and 9% of households with annual incomes of $50,000 or more.

Figure 2. U.S. Households Who Lost Their Savings During the COVID-19 Outbreak and Have No Savings to Fall Back On (in Percent)



NPR/Robert Wood Johnson Foundation/Harvard T.H. Chan School of Public Health, *Household Experiences in Major U.S. Cities During the Delta Variant Outbreak,* 8/2/21 – 9/7/21. N=3,616 U.S. adults ages 18+. Income defined as reported 2020 household income. *Lost savings during COVID-19 and have no current savings includes responses to Q8/Q8a – No to Q8. Currently, does your household have any savings to fall back on, or not? Yes to Q8a. And before the COVID-19 outbreak began, did your household have any savings to fall back on, or not?*

32% of households say they have a worse financial situation now than before the COVID-19 outbreak

In addition, 32% of U.S. households describe their own financial situation as worse now compared to before the COVID-19 outbreak, while 19% say it is better and 49% say it is about the same.

Among renters, 27% of them report serious problems paying rent in the past few months

At the time the Centers for Disease Control and Prevention's (CDC) eviction ban expired, 27% of renters nationally reported serious problems paying their rent in the past few months (see Figure 3). Among homeowners, only 7% reported serious problems paying their mortgage during this time.

Figure 3. Among Renters in the U.S., Serious Problems Paying Rent in the Past Few Months (in Percent)

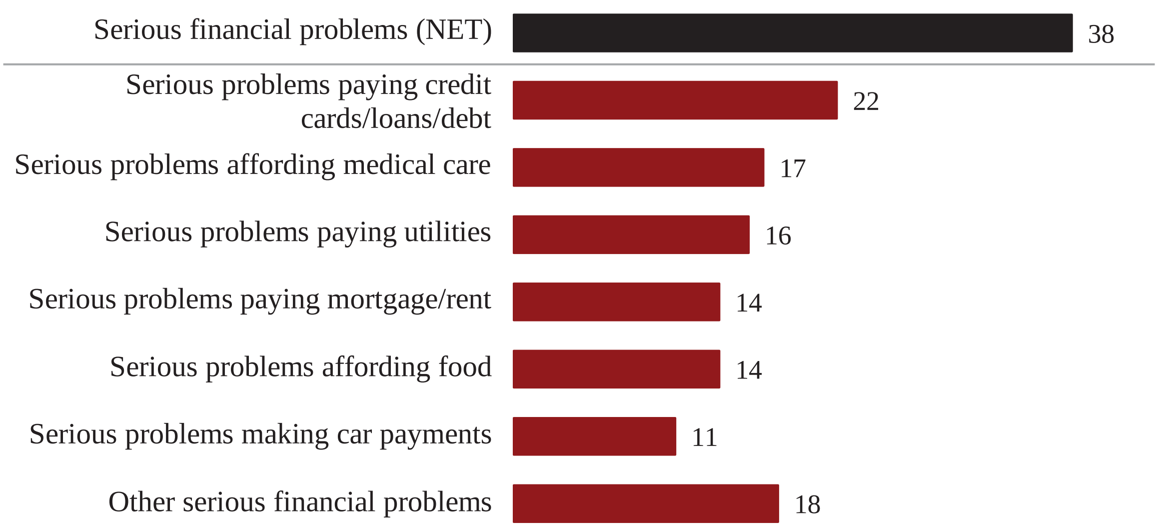
NPR/Robert Wood Johnson Foundation/Harvard T.H. Chan School of Public Health, *Household Experiences in America During the Delta Variant Outbreak*, 8/2/21 – 9/7/21. N=1,564 U.S. adults ages 18+ living in a rented home. *Q7a. In the past few months, have you or anyone living in your household been having serious problems paying the mortgage/rent?*

Serious financial problems in different areas

When it comes to serious financial problems in specific areas (see Figure 4), notable shares of households report problems in several areas, including 22% who report facing serious problems with paying credit cards, loans, or other debt, 17% who report serious problems affording medical care, and 16% who report serious problems paying utilities, like gas or electricity. In addition, 14% of households report serious problems affording food, 14% report serious problems paying their mortgage or rent, and 11% report serious problems making car payments, while 18% report facing other serious financial problems.

Figure 4. Serious Financial Problems Among U.S. Households in the Past Few Months (in Percent)

Q7. In the past few months, have you or anyone living in your household been having _______?



NPR/Robert Wood Johnson Foundation/Harvard T.H. Chan School of Public Health, *Household Experiences in America During the Delta Variant Outbreak*, 8/2/21 – 9/7/21. N=3,616 U.S. adults ages 18+. *Q7*.

Dan Tsubouchi @Energy_Tidbits · 4h

"investment required to decarbonise the UK economy is uncertain", may need more tax revenue "throughout the transition" per leaked UK Treasury report. Thx @tobyhelm twitter.com/tobyhelm/statu... Don't know or don't want to say like @POTUS, #OOTT #EnergyTransition

Biden Either Doesn't Estimate or Won't Say How Many $ Trillions To Get US to Carbon Neutral

Welcome to new Energy Tidbits memo readers. We are continuing to add new readers to our Energy Tidbits memo, energy blogs and tweets. The focus and concept for the memo was set in 1999 with input from PMs, who were looking for research (both positive and negative items) that helped them shape their investment thesis to the energy space, and not just focusing on daily trading. Our priority was and still is to not just report on events, but also try to interpret and point out implications therefrom. The best example is our review of investor days, conferences and earnings calls focusing on sector developments that are relevant to the sector and not just a specific company results. Our target is to write on 48 to 50 weekends per year and to post by noon mountain time on Sunday.

This week's memo highlights:

1. Granholm says the Biden administration doesn't have an estimate for how many $ trillions it will cost to get US to carbon neutral. (Click Here)
2. Biden looks to have lowered the bar for the potential removal of sanctions against Venezuela/Maduro. (Click Here)
3. Qatar warns underinvestment to cause a significant shortage of LNG in the 2025-2030 period. (Click Here)

Dan Tsubouchi @Energy_Tidbits · Jun 23

US can't control what CN IN actually spend to be #CarbonNeutral, but politics aside, shouldn't #Biden admin have a rough estimate of how many $trillions to get US to carbon neutral? How can anyone say #EnergyTransition won't cost more? #NatGas #OOTT
...

2

Dan Tsubouchi @Energy_Tidbits · 13h

#Vortexa crude oil floating storage for 10/15 est 97.41 mmb. Big revisions to Oct 8 est. Oct 8 now est 101.06 mmb vs 82.99 mm est as of 10/09. 10/15 is +18.63 mmb vs recent 06/25 trough of 78.78 mmb. But -123.44 mmb vs 06/26/2020 peak 220.85 mmb. Thx @Vortexa @TheTerminal #OOTT

2 6

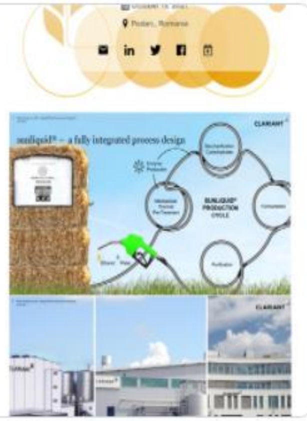
SAF

Dan Tsubouchi @Energy_Tidbits · 23h

1/2. Why 2G #Biofuels will be profitable & why energy costs are going way higher under #EnergyTransition. #Clariant CEO on Podari biofuels from straw "We expect double the price to first generation," That's "simply because it's legislated," he said. Thx @RefinedRachel #OOTT

...o become a highly profitable venture in Europe, according to a firm that just opened a production site in the continent.
Clariant AG, a Swiss chemicals maker, just opened a facility in Romania to make so-called advanced biofuels, which use agricultural waste or non-edible crops to make fuels that can be blended into gasoline and diesel. That's environmentally better than so-called first-generation ethanol currently on the market, which is made from foodstuffs like sugar or corn.
The carbon savings from the new approach will make ethanol that's more profitable compared with existing processes, Clariant Chief Executive Officer Conrad Keijzer said on a conference call.
"We expect double the price to first generation," he said. That's "simply because it's legislated," he said.
Clariant built the plant mainly to promote its technology, which it now wants to license to other companies.
The European Union has set a target that at least 0.2% of all transport fuels should be made from advanced biofuels next year, rising to 2.2% in 2030.
Clariant's technology could also be used in chemicals and aviation. "This is a prime example of a circular economy solution," Keijzer said.

To contact the reporter on this story:
Rachel Graham in London at rgraham13@bloomberg.net



1 2 2

SAF

Dan Tsubouchi @Energy_Tidbits · 23h

2/2. Recall @TotalEnergies @PPouyanne "we have invested a lot of money like other players to try to make what we call the 2G, 2g-generation biofuels to become a reality without a lot of success, to be honest". #EnergyTransition is happening but will be very expensive. #OOTT

The next question comes from the line of Michele Della Vigna from Goldman Sachs.

Michele della Vigna, Goldman Sachs Group, Inc.:
Thank you very much for the comprehensive presentation. My question really has to do with bio energy, which plays a major part in your scenarios, but to be fair, also in several other Net-Zero scenarios, especially for aviation and for shipping. And I was wondering, how confident you feel that the raw material will be there to fuel such a substantial growth there without really competing on the other side with the role of nature-based solutions and also without the key role of agriculture to supply food for a growing global population. Thank you.

Patrick Pouyanne, TotalEnergies SE:
Helle, it's a very good question for me. It's why, by the way we have probably increased as well in our scenario what I call the hydrogen-based liquids either [?] fuel, synthetic fuels because it's very true. Maybe our own experience. you know we have suffered a little. I will come back on it with the [?] and I think it's not only the end, the soybean tomorrow, I think in Europe. So my view is that -- and you also know that in our industry, we have invested a lot of money like other players to try to make what we call the 2G, 2g-generation biofuels to become a reality without a lot of success, to be honest.
So in my view, there will be, of course I would say the biofuels are immediately available. So we can begin to make, for example, sustainable aviation fuels with biofuels. I have a first generation or even what I call some wasted animal fats or used cook oil, but there will be a limit to that. Obviously in this type of feedstock, which is quite limited, in fact, on the planet.
So and I agree with you that the competition with agriculture and -- will be also limited to the first generation biofuels. It depends, of course on the senseity of the continent, but what happened in Europe, I think we're

1 2 1

Dan Tsubouchi @Energy_Tidbits · Oct 15

"We are fooling ourselves if we believe by restricting supply with our traditional hydrocarbon companies, that only raises energy costs, which we're witnessing now" says $BLK CEO. #Oil #NatGas CEOs wish he had said this 1, 2 yrs ago before capital was squeezed off. #OOTT

Excerpts from BlackRock Q3 call transcript on Oct 13

BlackRock CEO Larry Fink prepared remarks ""*Inflationary trends are appearing more than transitory, reflecting structural changes, including a shift from consumerism to job creation, rising wage growth and the energy transition. As I said in a speech to the G20 in July, society needs to rapidly invest in innovation to offset inflationary pressures associated with the transition to a net zero economy.*"

BlackRock CEO Larry Fink in Q&A. ""*We're going to be fooling ourselves to getting to a net-zero world if we're only asking public companies. We are fooling ourselves if we believe by restricting supply with our traditional hydrocarbon companies, that only raises energy costs, which we're witnessing now. And that is creating not a just transition, which I spoke about in my last two CEO letters. So we have to be vocal. We have to be forceful about it.*"

8 12

Dan Tsubouchi @Energy_Tidbits · Oct 14

Does UK #EnergyCrisis show UK reached tipping point on how fast can add intermittent #Wind #Solar to replace 24/7 #NatGas w/o realistic plan for reliable power? Did UK forget the last mile (or GW) is the most complex & expensive? Thx @BloombergNEF Andreas Gandolfo #OOTT

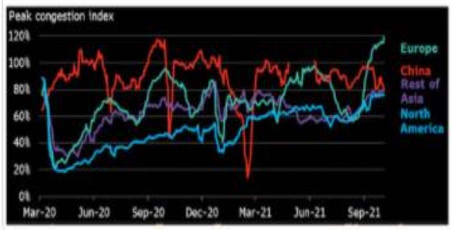
2 3

Dan Tsubouchi @Energy_Tidbits · Oct 14

Global road traffic activity holding up despite high fuel prices & end of peak summer season. Other than China that was hit by Golden Week holiday. Imagine the boost to #Oil when things get back to normal. Thx @BloombergNEF Danny Adkins. #OOTT

Excerpt from Bloomberg TOPLive coverage of EIA weekly oil inventory data
10/14 10:56
Global road traffic activity is holding up for the time being, despite high fuel prices and the end of the peak summer driving season. According to BloombergNEF calculations based on TomTom's congestion data, aggregated road traffic in the first week of October saw gains in all tracked regions outside of China, which fell due to the Golden Week holiday. While traffic remains firmly below pre-pandemic levels in most regions, driving activity around the world does appear to be showing resilience as fuel prices continue to rise.
Regionally aggregated traffic congestion relative to 2019 levels

Danny Adkins BNEF Analyst



2 4

Dan Tsubouchi @Energy_Tidbits · Oct 14

For those not near their laptop, @EIAgov weekly #Oil #Gasoline #Distillates inventory data just out. Prior to release, WTI was $81.27. #OOTT

ir.eia.gov/wpsr/overview....

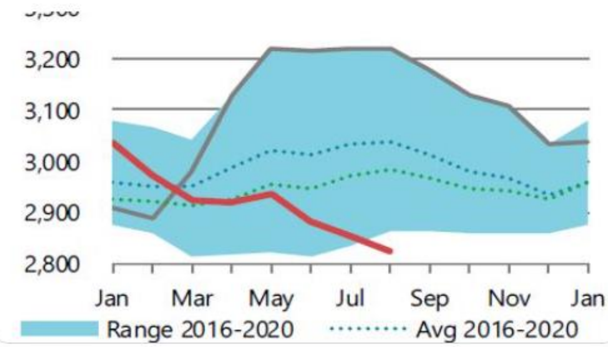
Oil/Products Inventory Oct 8: EIA, Bloomberg Survey Expectations, API			
(million barrels)	EIA	Expectations	API
Oil	6.09	1.05	5.21
Gasoline	-1.96	1.00	-4.58
Distillates	-0.02	-1.00	-2.71
	4.11	1.05	-2.08
Note: In addition, there was 0.8 mmb draw from SPR for Oct 8 week to 617.0 mmb			
Note: Included in the data, Cushing had a draw if 1,868 mmb for Oct 8 week			
Source EIA, Bloomberg			
Prepared by SAF Group			

2

Dan Tsubouchi @Energy_Tidbits · Oct 14

Thx @JohnHKingston for this bullish Aug oil stocks chart. Plus @IEA says Sept is even better, preliminary data shows OECD industry stocks fell 23 mb in Sept to stand 210 mb below their 5-yr average & at their lowest level since March 2015. #OOTT

> **John Kingston** @JohnHKingston · Oct 14
>
> This is a chart of total #oil stocks in OECD nations just published by @IEA. The red line is the current level of stocks. The blue area is the range the last five years. It doesn't really need any additional commentary; the picture very much is worth a thousand words.



4 11

Dan Tsubouchi @Energy_Tidbits · Oct 14

Can EU policymakers withstand public & some members pressure on record #NatGas prices & wait until after #COP26 ends Nov 12 before seeing if they want to give in & try to force #NordStream2 final approvals? Novak reminds it is ready for operation in the coming days. #OOTT.

RUSSIAN ENERGY WEEK - 2021

Novak said Nord Stream 2 will be ready to launch in the coming days

The Deputy Prime Minister noted that the pipe is being filled with gas

MOSCOW, October 14. / TASS /. The Nord Stream 2 gas pipeline will be ready for launch in the coming days, the pipeline is already being filled with gas. This was announced by Deputy Prime Minister of the Russian Federation Alexander Novak during a session at the Russian Energy Week.

Nord Stream 2 has been completed. Commissioning and filling of the pipe with the required technological amount of gas are underway. And I believe that it will be ready for operation in the coming days, in order to launch it, "Novak said.

At the same time, he noted that the further situation with the operation of the pipeline depends on the European regulator. Commercial gas supplies via Nord Stream 2 may begin immediately after obtaining permission from the regulator, the Deputy Prime Minister stressed, adding that supplies also depend on applications from European consumers.

On October 4, the Danish Energy Agency announced that Nord Stream 2 AG had fulfilled all the conditions for putting Nord Stream 2 into operation. The company announced the start of filling the first string of the gas pipeline with gas. Commissioning work on the second line continues.

About Forum

The International Forum "Russian Energy Week" is a discussion platform in Russia aimed at discussing the challenges and prospects for the development of the world fuel and energy complex. This year the conference is being held in the Moscow Manege on October 13-15. In total, the forum will include more than 30 business events, in which the heads of more than 200 companies from various sectors of the fuel and energy complex will take part. The Global Energy Prize laureates were also awarded within the framework of the forum. By tradition, the program of the forum will end on October 15, the youth day.

4 3

Dan Tsubouchi @Energy_Tidbits · Oct 14

Saudi's answer to @POTUS asking #OPEC+ to export more #Oil. Another great KSA Energy Minister Abdulaziz quote "it is important to always look a little further than the tip of your nose. And if you look at 2022, you will see a lot of excess stocks". #OOTT

pandemic crisis, but there are risks of overproduction of oil as early as 2022. This opinion was expressed by the Minister of Energy of Saudi Arabia, Prince Abdel Aziz bin Salman.

According to him, the oil reserves of the OECD countries, the level of which OPEC + is guided by in its actions, really decreased compared to the 2020 crisis year. "And we think that by the end of this year we will see a very balanced situation. But it is important to always look a little further than the tip of your nose. And if you look at 2022, you will see a lot of excess stocks," he said, noting that "such arithmetic consists of data from eight independent sources."

The minister also added that the OPEC + countries can continue to increase oil production by 400 thousand bpd per month "in the next four months."

The Minister of Energy also said that the situation in the markets for natural gas, liquefied natural gas (LNG) and coal, which are experiencing a period of price peaks, is caused by insufficient investment in these industries and a lack of regulation, like OPEC +.

According to bin Salman, "carbon neutrality should not be an end in itself," as such ambitions disrupt stability in energy markets. "We are already seeing a 500% rise in gas prices, very high coal prices and a 200% rise in LNG prices. undoubtedly, the situation there would be much better now, "he said.

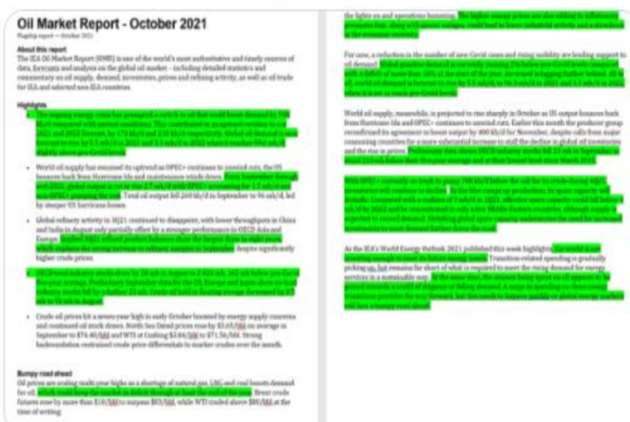
"If we look at the gas and coal market, we see that they need a similar regulator. Perhaps they should just copy past and repeat what we do in the oil market," he suggested.

The International Forum "Russian Energy Week" is a discussion platform in Russia aimed at

1 6 21

Dan Tsubouchi @Energy_Tidbits · Oct 14

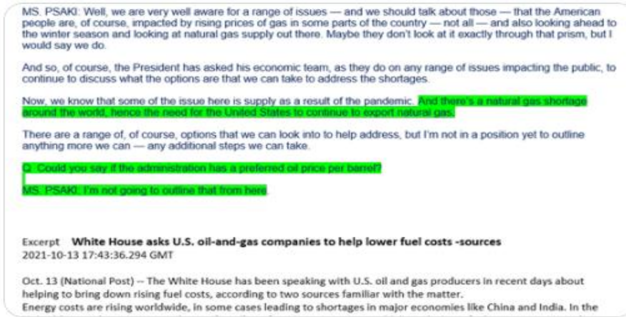
Multiple bullish #Oil items in @IEA OMR. Demand +170 kb/d in 21, +210 kb/d in 22, over >pre-Covid in 22. largest 3Q21 refined product draw in 8 yrs. OECD industry stocks in Sept at lowest level since Mar 2015. Spare oil capacity <4 mb/d by 2Q22. #OPEC loving this forecast #OOTT



2 10

Dan Tsubouchi @Energy_Tidbits · Oct 13

#OPEC must love it that US would rather ask them to increase exports than help restore US oil production to pre-Covid levels. @jrpsaki confirms @POTUS admin not in contact with US #Oil co's to help bring down fuel costs. Positive for #Oil prices


MS. PSAKI: Well, we are very well aware for a range of issues — and we should talk about those — that the American people are, of course, impacted by rising prices of gas in some parts of the country — not all — and also looking ahead to the winter season and looking at natural gas supply out there. Maybe they don't look at it exactly through that prism, but I would say we do.

And so, of course, the President has asked his economic team, as they do on any range of issues impacting the public, to continue to discuss what the options are that we can take to address the shortages.

Now, we know that some of the issue here is supply as a result of the pandemic. And there's a natural gas shortage around the world, hence the need for the United States to continue to export natural gas.

There are a range of, of course, options that we can look into to help address, but I'm not in a position yet to outline anything more we can — any additional steps we can take.

Q Could you say if the administration has a preferred oil price per barrel?

MS. PSAKI: I'm not going to outline that from here.

Excerpt **White House asks U.S. oil-and-gas companies to help lower fuel costs -sources**
2021-10-13 17:43:36.294 GMT

Oct. 13 (National Post) -- The White House has been speaking with U.S. oil and gas producers in recent days about helping to bring down rising fuel costs, according to two sources familiar with the matter.
Energy costs are rising worldwide, in some cases leading to shortages in major economies like China and India. In the

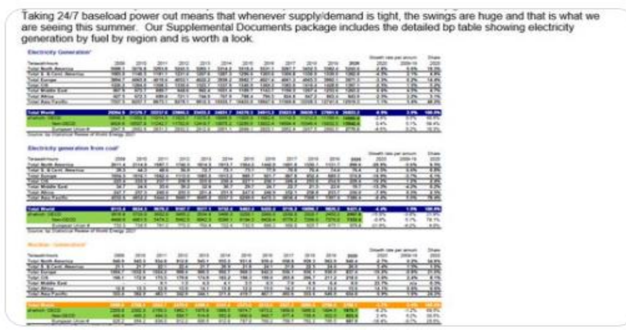
Dan Tsubouchi @Energy_Tidbits · Oct 9

Positive for OPEC. why keep a lid on US #Oil production instead of asking #OPEC's help? @jrpsaki doesn't really answer other than return from #Ida. Rather pivots to ensure "production and rise of renewables". A no answer to the question is a "NO" ...

3 4

Dan Tsubouchi @Energy_Tidbits · Oct 13

"the rise in #NatGas prices in Europe was the result of a shortage of electriicty, and not vice versa" & no such crisis when #Nuclear/#Coal were in the lead says Putin. Data shows EU replaced 24/7 baseload coal/nuclear with intermittent #Wind #Solar in last decade. #OOTT


Taking 24/7 baseload power out means that whenever supply/demand is tight, the swings are huge and that is what we are seeing this summer. Our Supplemental Documents package includes the detailed bp table showing electricity generation by fuel by region and is worth a look.

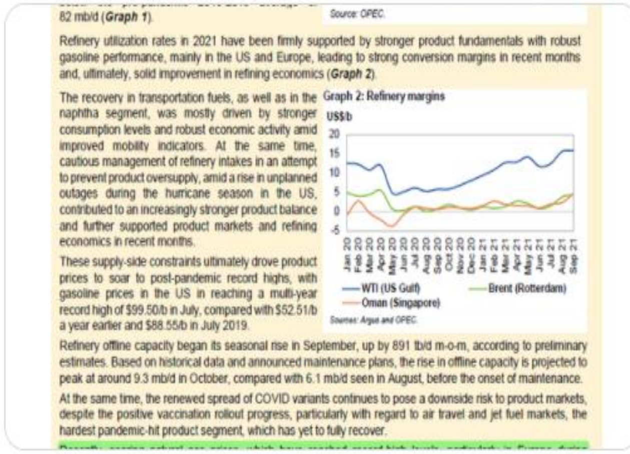
Dan Tsubouchi @Energy_Tidbits · Aug 6

Positive to #NatGas #LNG in 2020s. OECD's steady replacement of 24/7 #Coal #Nuclear baseload with variable #Renewable means OECD #Electricity prices spike/shortage risk when supply/demand gets tight. China/India just increase coal. #Electricity will cost ...

3 7

Dan Tsubouchi @Energy_Tidbits · Oct 13

ICYMI, Most #Oil demand forecasts assume record high #NatGas #LNG prices leads to switchng to heating and fuel oil ie. near term boost of 0.5 to 1 mmb/d. #OPEC's MOMR only notes it as a potential upside. #OOTT



82 mb/d (*Graph 1*).

Source: OPEC.

Refinery utilization rates in 2021 have been firmly supported by stronger product fundamentals with robust gasoline performance, mainly in the US and Europe, leading to strong conversion margins in recent months and, ultimately, solid improvement in refining economics (*Graph 2*).

The recovery in transportation fuels, as well as in the naphtha segment, was mostly driven by stronger consumption levels and robust economic activity amid improved mobility indicators. At the same time, cautious management of refinery intakes in an attempt to prevent product oversupply, amid a rise in unplanned outages during the hurricane season in the US, contributed to an increasingly stronger product balance and further supported product markets and refining economics in recent months.

These supply-side constraints ultimately drove product prices to soar to post-pandemic record highs, with gasoline prices in the US in reaching a multi-year record high of $99.50/b in July, compared with $52.51/b a year earlier and $88.55/b in July 2019.

Graph 2: Refinery margins

Sources: Argus and OPEC.

Refinery offline capacity began its seasonal rise in September, up by 891 tb/d m-o-m, according to preliminary estimates. Based on historical data and announced maintenance plans, the rise in offline capacity is projected to peak at around 9.3 mb/d in October, compared with 6.1 mb/d seen in August, before the onset of maintenance.

At the same time, the renewed spread of COVID variants continues to pose a downside risk to product markets, despite the positive vaccination rollout progress, particularly with regard to air travel and jet fuel markets, the hardest pandemic-hit product segment, which has yet to fully recover.

5 8

Dan Tsubouchi @Energy_Tidbits · Oct 13

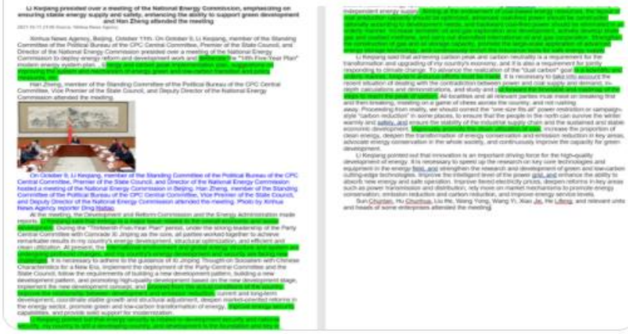
Here's why #Oil #NatGas prices will be way stronger for 2020s/2030s if world doesn't abruptly pivot to cutting demand to reach #NetZero. @IEA says O&G capex is at #NetZero demand levels, nowhere close to level needed for stated & announced policies demand. Good for #OPEC. #OOTT

1 4 9

Dan Tsubouchi @Energy_Tidbits · Oct 12

Sounds like China struggling with growth. China "is still a developing country, and development is the foundation and key to solving all problems." So much more in this China statement. #OOTT #Coal #NatGas #Oil #EnergyTransition

> **Dan Tsubouchi** @Energy_Tidbits · Oct 12
>
> Must read. Bullish for #Coal #NatGas #Oil. Not just for this winter, China changing 5-yr plan to improve energy security. Increase coal generation, strengthen construction NatGas & Oil storage capacity. Develop new timetable/roadmap to reach carbon peak #OOTT #EnergyTransition twitter.com/Energy_Tidbits...



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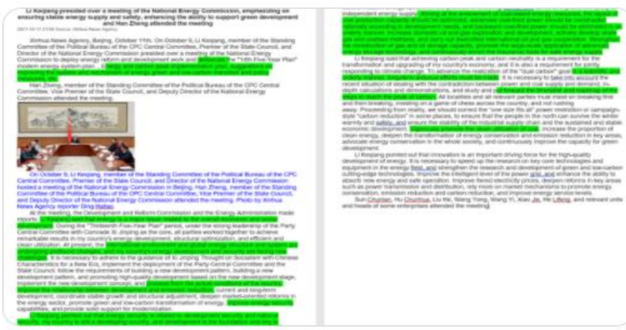


> **Dan Tsubouchi** @Energy_Tidbits · Oct 8
>
> 
>
> Must read, bullish for #NatGas #Coal #Oil this winter with China priority to ensure energy security for economy. Incl priority for coal generation, "actively promote the construction of coal, natural gas, crude oil reserves and storage capacity", and more. #OOTT

1 20 48

Dan Tsubouchi @Energy_Tidbits · Oct 11

No doubt on @WHO position, "burning of fossil fuels is killing us", want absolute end to #FossilFuel subsidies, complete phase out of #Coal in OECD by 2030, non-OECD by 2040, effective taxation needed, "pricing the negative health & economic externalities" from #FossilFuel. #OOTT

World Health Organization (WHO) @WHO · Oct 11

WHO's 10 calls for #ClimateAction ❗

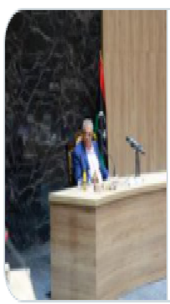
1 Commit to a healthy recovery
2 Place health at the ❤ of the climate talks
3 Harness the health benefits of climate action...

Show this thread

1 2

Dan Tsubouchi @Energy_Tidbits · Oct 11

Is the real question, what happens AFTER the #Libya Dec 24 election? Will both the east (incl Haftar) & west be committed to unified Libya? @libyaherald report shows lots of issues from the east. In Sept 2020, #Oil production was <200,000 b/d #OOTT



libyaherald.com

Libya on brink of another west-east split and unrav...

By Sami Zaptia. London, 11 October 2021: With the 24 December 2021 elections looking in the balanc...

1 3

Dan Tsubouchi @Energy_Tidbits · Oct 11

Best indicators of increasing LNG supply gap in 2020s. Asian LNG buyers keep locking in long term #LNG supply. New #Cheniere 13-yr deal with ENN for its China #NatGas distribution network.   See SAF July 14 8-pg blog safgroup.ca/news-insights/ #OOTT

Asian LNG Buyers Abruptly Change and Lock in Long Term Supply – Validates Supply Gap, Provides Support For Brownfield LNG FIDs

m LNG Sale and Purchase Agreement

5 8

Dan Tsubouchi @Energy_Tidbits · Oct 11

For those not near their laptop. WTI $82 #OOTT

Happy Thanksgiving!

20

Dan Tsubouchi @Energy_Tidbits · Oct 10

its now posted

> **Dan Tsubouchi** @Energy_Tidbits · Oct 10
>
> Our weekly SAF Oct 10, 2021 Energy Tidbits memo is posted on our SAF Group website. This 38-pg energy research memo expands upon & covers more items than tweeted this week. See news/insights section of SAF website #Oil #OOTT #LNG #NatGas #EnergyTransition safgroup.ca/news-insights/
>
> **Welcome to new Energy Tidbits memo readers.** We are continuing to add new readers to our Energy Tidbits memo, energy blogs and tweets. The focus and concept for the memo was set in 1999 with input from PMs, who were looking for research (both positive and negative items) that helped them shape their investment thesis to the energy space, and not just focusing on daily trading. Our priority was and still is to not just report on events, but also try to interpret and point out implications therefrom. The best example is our review of investor days, conferences and earnings calls focusing on sector developments that are relevant to the sector and not just a specific company results. Our target is to write on 48 to 50 weekends per year and to post by noon mountain time on Sunday.
>
> This week's memo highlights:
>
> 1. China prioritizes energy/electricity supply this winter so will be building up, not reducing coal, natural gas, crude oil reserve and storage capacity (Click Here)
> 2. Reminder Nord Stream 2 faces a 2-mth EU review period after the 4-mth Germany review period ie. not likely a help this winter. (Click Here)
> 3. IEA seems to warn that a more realistic scenario is that peak oil demand isn't until around 2030 (Click Here)
> 4. Positive for OPEC+, White House ducks answering why keep a lid on US oil production instead of asking OPEC for more oil supply. (Click Here)
> 5. Unique thesis from DEBKA of a potential US/Russia/Iran/Israel different nuclear deal. (Click Here)
> 6. Please follow us on Twitter at [LINK] for breaking news that ultimately ends up in the weekly Energy Tidbits memo that doesn't get posted until Sunday noon MT

1 2 6

Dan Tsubouchi @Energy_Tidbits · Oct 10

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