Energy Tidbits

July 18, 2021

Produced by: Dan Tsubouchi

Supplemental Documents

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

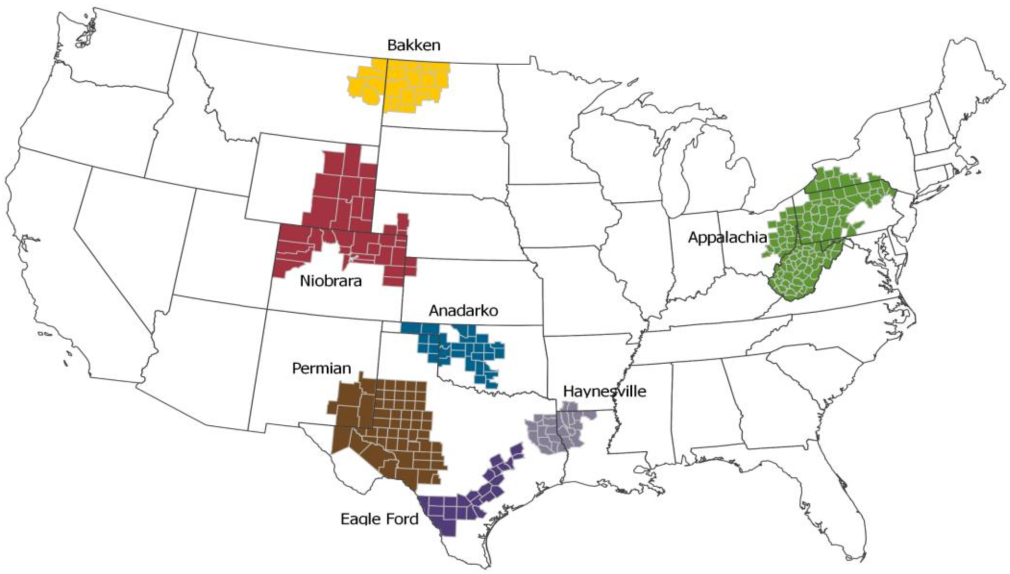
Independent Statistics & Analysis

U.S. Energy Information Administration

July 2021

Drilling Productivity Report

For key tight oil and shale gas regions



Note:

The DPR rig productivity metric *new-well oil/gas production per rig* can become unstable during periods of rapid decreases or increases in the number of active rigs and well completions. The metric uses a fixed ratio of estimated total production from new wells divided by the region's monthly rig count, lagged by two months. The metric does not represent new-well oil/natural gas production per newly completed well.

The DPR metric *legacy oil/gas production change* can become unstable during periods of rapid decreases or increases in the volume of well production curtailments or shut-ins. This effect has been observed during winter weather freeze-offs, extreme flooding events, and the 2020 global oil demand contraction. The DPR methodology involves applying smoothing techniques to most of the data series because of inherent noise in the data.

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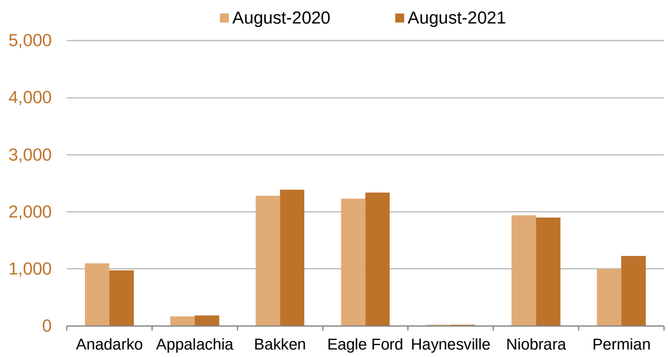
Year-over-year summary

July 2021

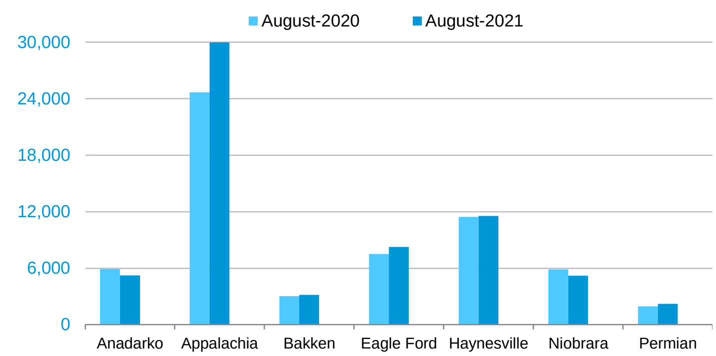
Drilling Productivity Report

drilling data through June
projected production through August

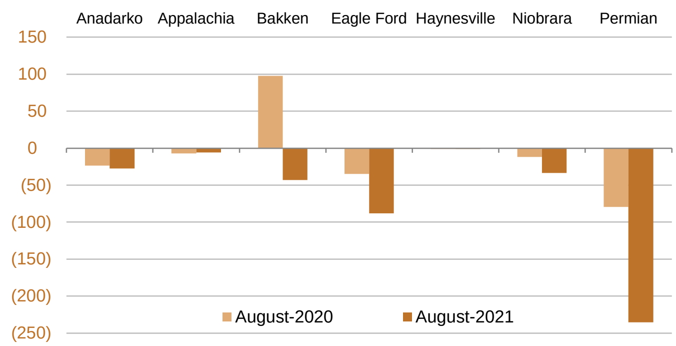
New-well oil production per rig
barrels/day



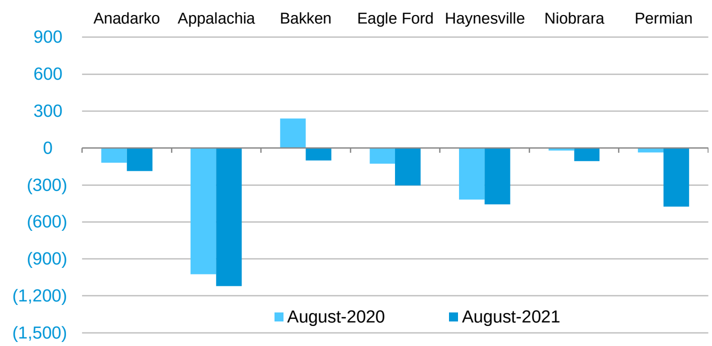
New-well gas production per rig
thousand cubic feet/day



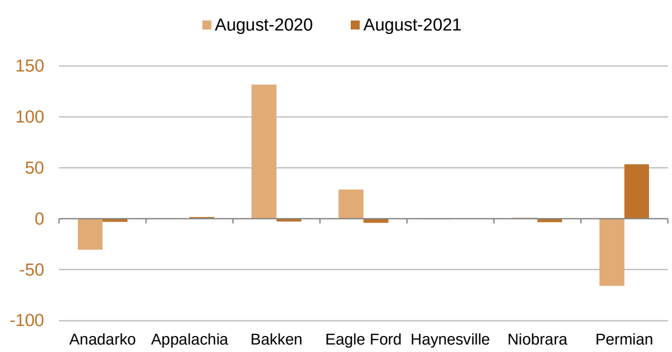
Legacy oil production change
thousand barrels/day



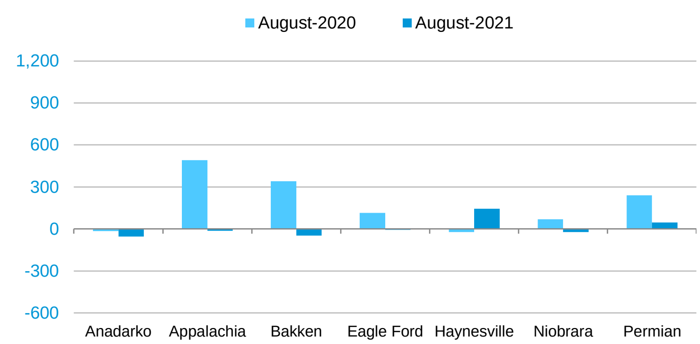
Legacy gas production change
million cubic feet/day



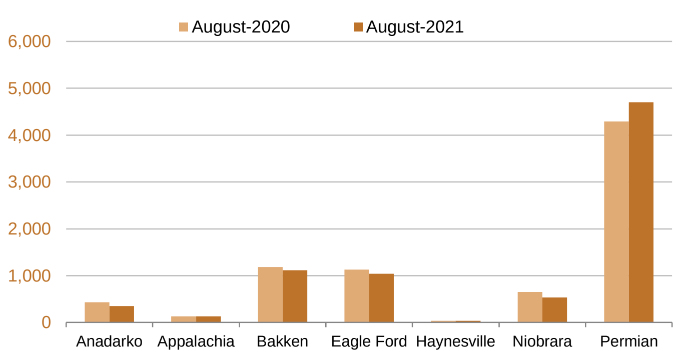
Indicated monthly change in oil production (Aug vs. Jul)
thousand barrels/day



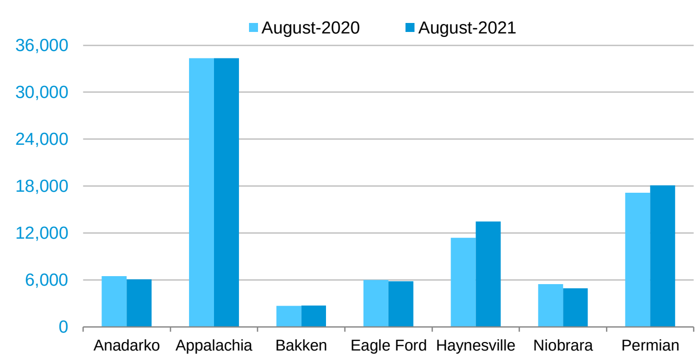
Indicated monthly change in gas production (Aug vs. Jul)
million cubic feet/day



Oil production
thousand barrels/day



Natural gas production
million cubic feet/day



Anadarko Region

Drilling Productivity Report

July 2021

drilling data through June
projected production through August

Oil
-19
barrels/day
month over month

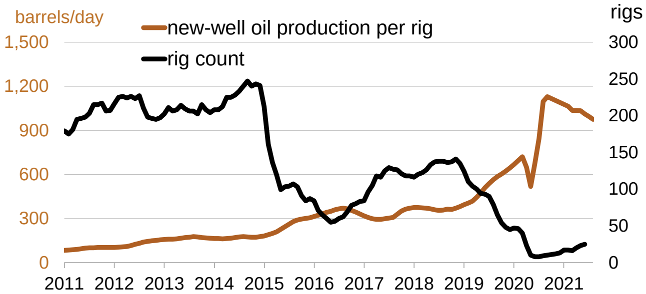
974 *August*
993 *July*
barrels/day

Monthly additions from one average rig

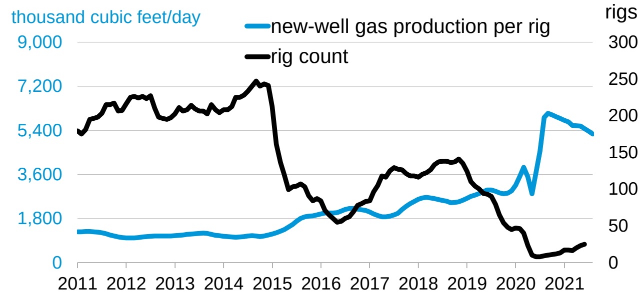
August **5,249**
July **5,356**
thousand cubic feet/day

Gas
-107
thousand cubic feet/day
month over month

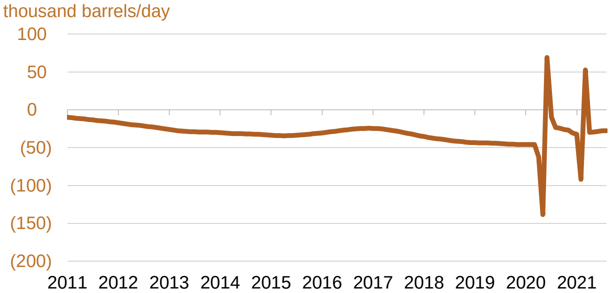
Anadarko Region
New-well oil production per rig



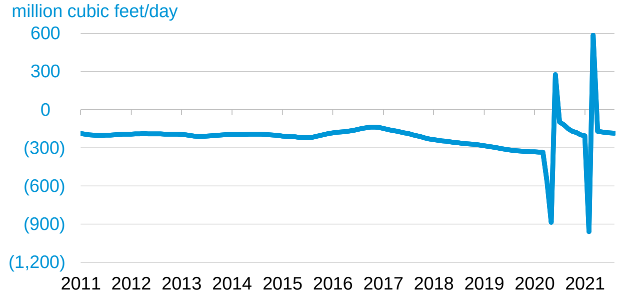
Anadarko Region
New-well gas production per rig



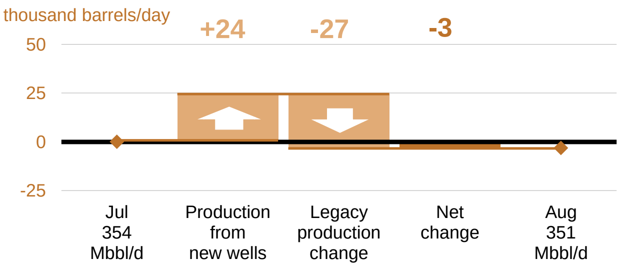
Anadarko Region
Legacy oil production change



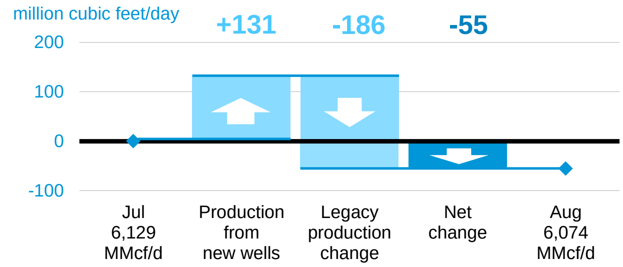
Anadarko Region
Legacy gas production change



Anadarko Region
Indicated change in oil production (Aug vs. Jul)

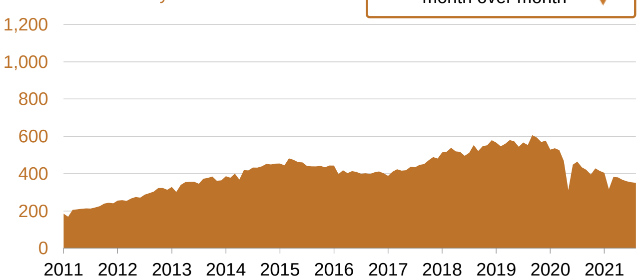


Anadarko Region
Indicated change in natural gas production (Aug vs. Jul)



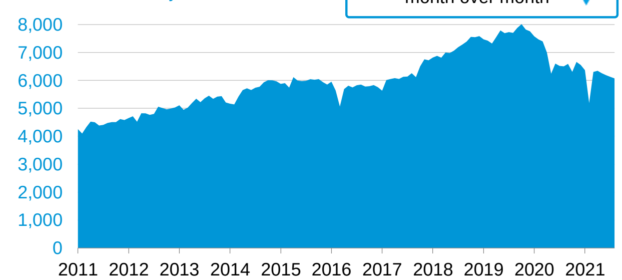
Anadarko Region
Oil production
thousand barrels/day

Oil -3
thousand barrels/day
month over month



Anadarko Region
Natural gas production
million cubic feet/day

Gas -55
million cubic feet/day
month over month



Appalachia Region

Drilling Productivity Report

July 2021

drilling data through June
projected production through August

Oil +1 barrels/day month over month

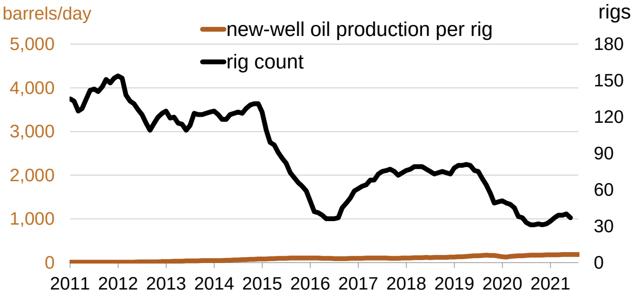
186 *August*
185 *July*
barrels/day

Monthly additions from one average rig

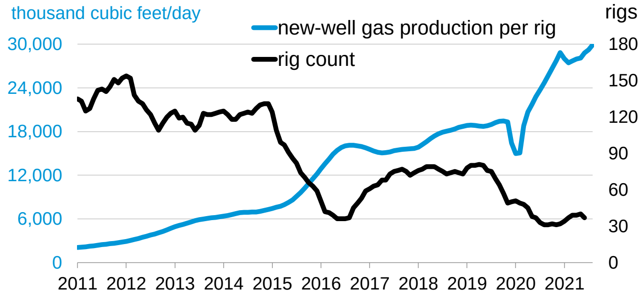
August **29,971**
July **29,240**
thousand cubic feet/day

Gas +731 thousand cubic feet/day month over month

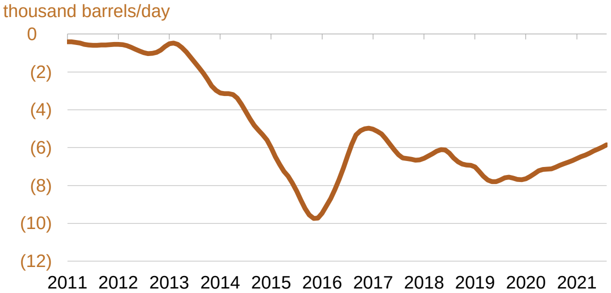
Appalachia Region
New-well oil production per rig



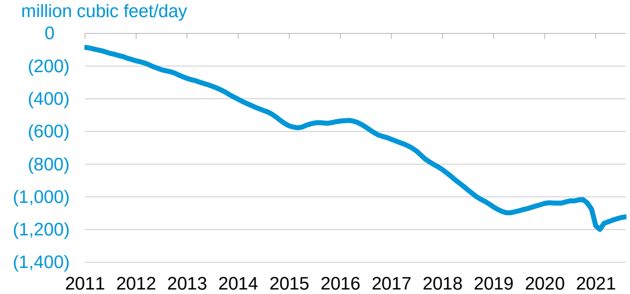
Appalachia Region
New-well gas production per rig



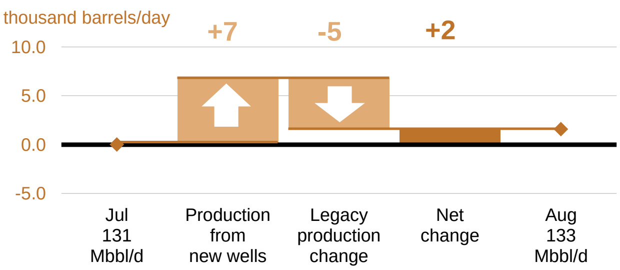
Appalachia Region
Legacy oil production change



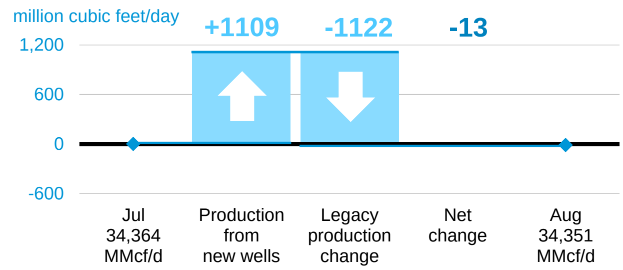
Appalachia Region
Legacy gas production change



Appalachia Region
Indicated change in oil production (Aug vs. Jul)

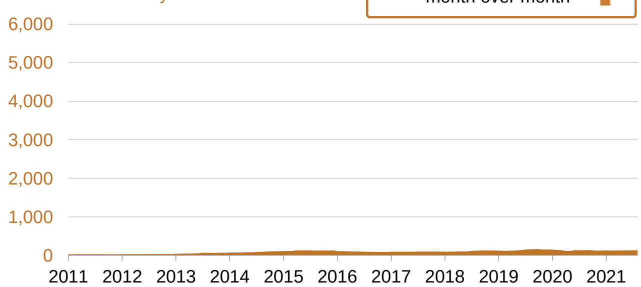


Appalachia Region
Indicated change in natural gas production (Aug vs. Jul)



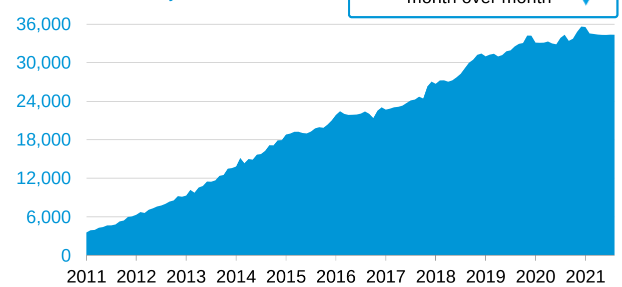
Appalachia Region
Oil production

Oil +2 thousand barrels/day month over month



Appalachia Region
Natural gas production

Gas -13 million cubic feet/day month over month



Bakken Region

Drilling Productivity Report

July 2021

drilling data through June
projected production through August

Oil
-12
barrels/day
month over month

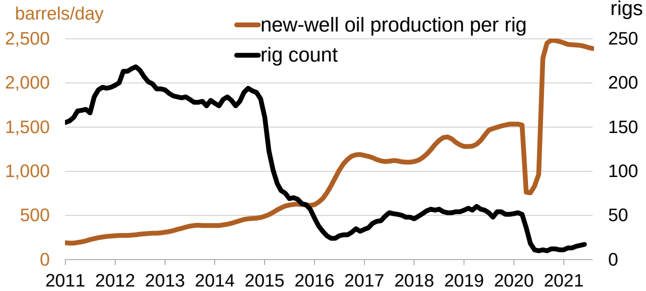
2,388 *August*
2,400 *July*
barrels/day

Monthly additions from one average rig

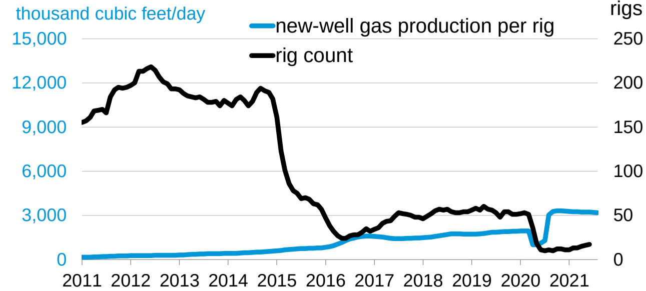
August **3,176**
July **3,192**
thousand cubic feet/day

Gas
-16
thousand cubic feet/day
month over month

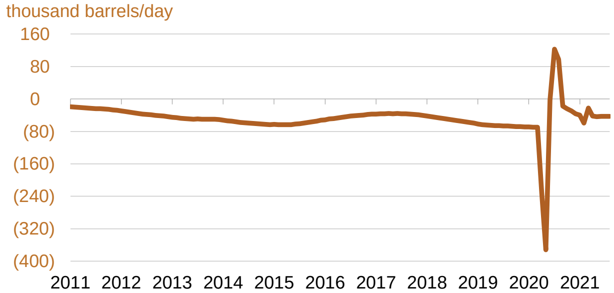
Bakken Region
New-well oil production per rig



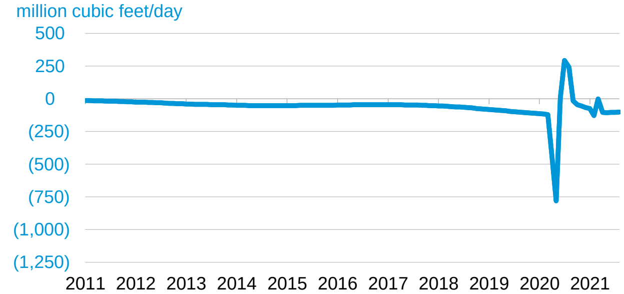
Bakken Region
New-well gas production per rig



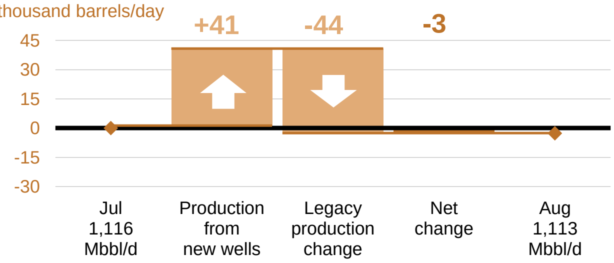
Bakken Region
Legacy oil production change



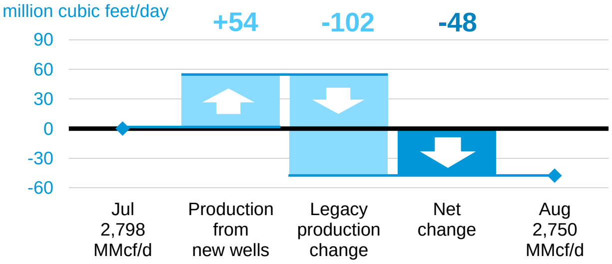
Bakken Region
Legacy gas production change



Bakken Region
Indicated change in oil production (Aug vs. Jul)

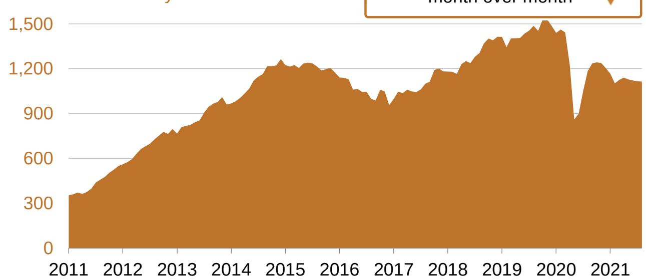


Bakken Region
Indicated change in natural gas production (Aug vs. Jul)



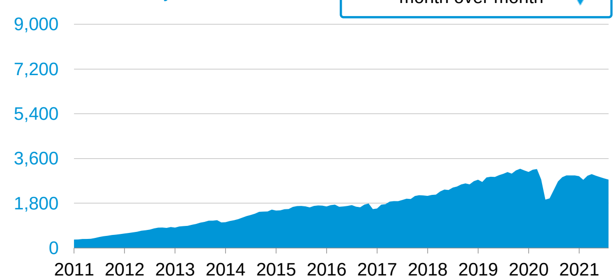
Bakken Region
Oil production

Oil -3
thousand barrels/day
month over month



Bakken Region
Natural gas production

Gas -48
million cubic feet/day
month over month



Eagle Ford Region

Drilling Productivity Report

July 2021

drilling data through June
projected production through August

Oil +2
barrels/day
month over month

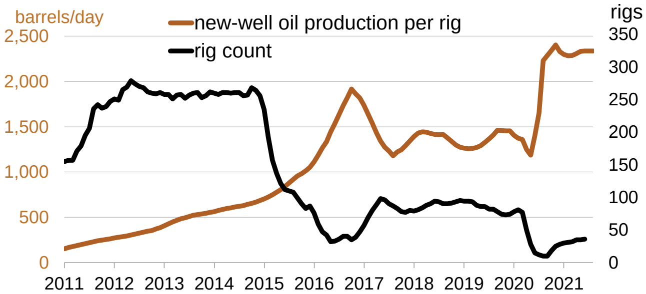
2,338 *August*
2,336 *July*
barrels/day

Monthly additions from one average rig

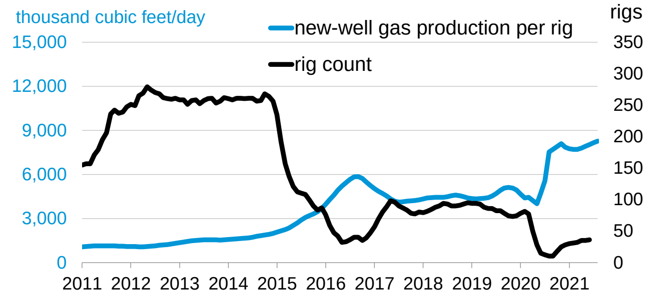
August **8,267**
July **8,145**
thousand cubic feet/day

Gas +122
thousand cubic feet/day
month over month

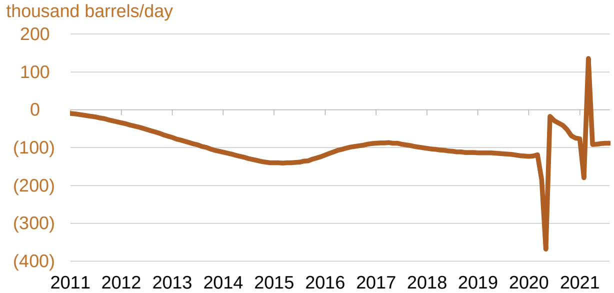
Eagle Ford Region
New-well oil production per rig **Rig count**



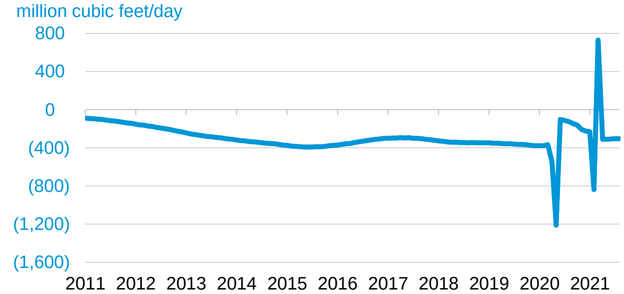
Eagle Ford Region
New-well gas production per rig **Rig count**



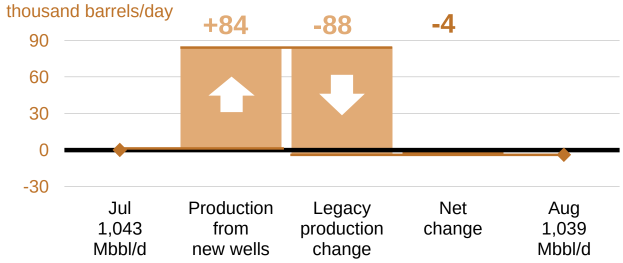
Eagle Ford Region
Legacy oil production change



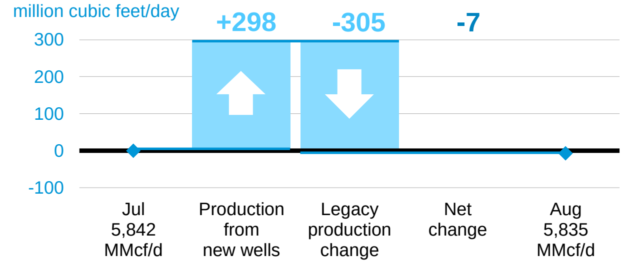
Eagle Ford Region
Legacy gas production change



Eagle Ford Region
Indicated change in oil production (Aug vs. Jul)

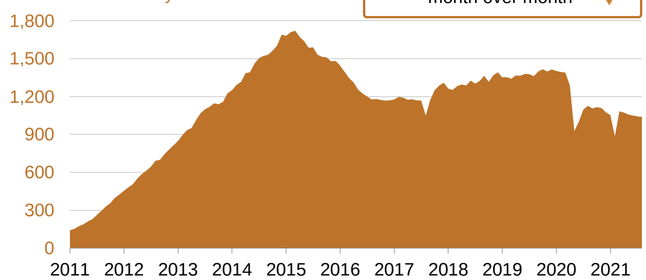


Eagle Ford Region
Indicated change in natural gas production (Aug vs. Jul)



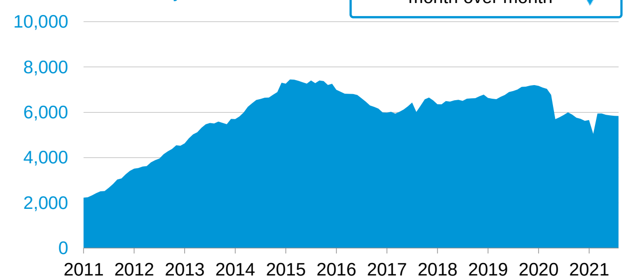
Eagle Ford Region
Oil production

Oil -4
thousand barrels/day
month over month



Eagle Ford Region
Natural gas production

Gas -7
million cubic feet/day
month over month



Haynesville Region

Drilling Productivity Report

July 2021

drilling data through June
projected production through August

Oil
0
barrels/day
month over month

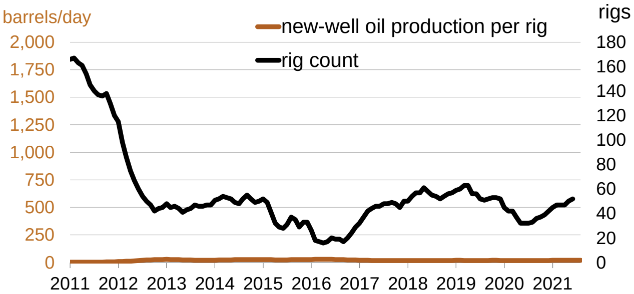
19 *August*
19 *July*
barrels/day

Monthly additions from one average rig

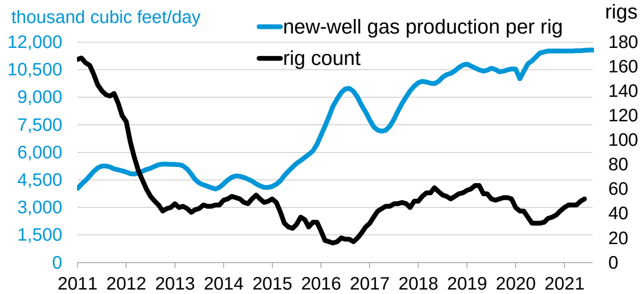
August **11,571**
July **11,560**
thousand cubic feet/day

Gas
+11
thousand cubic feet/day
month over month

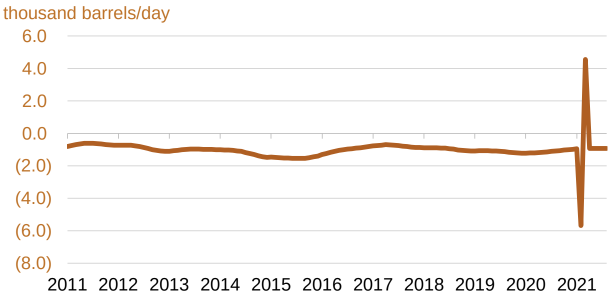
Haynesville Region
New-well oil production per rig **Rig count**



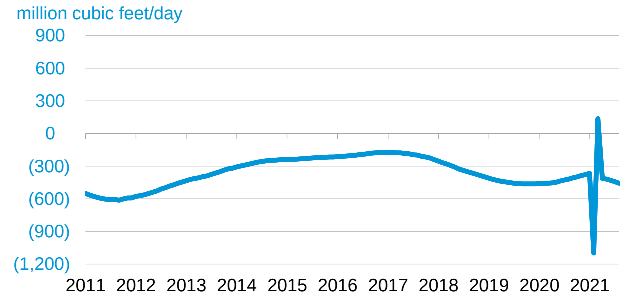
Haynesville Region
New-well gas production per rig **Rig count**



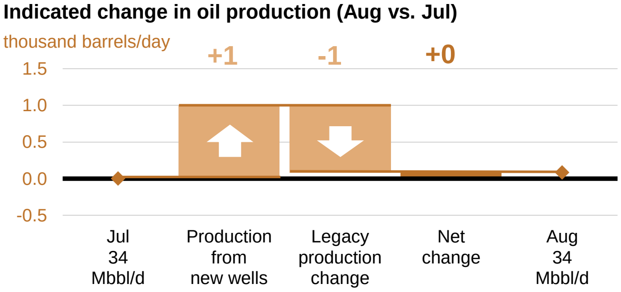
Haynesville Region
Legacy oil production change



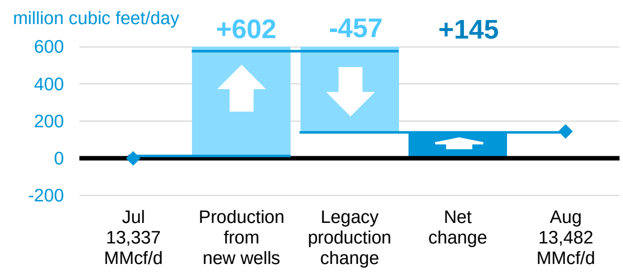
Haynesville Region
Legacy gas production change



Haynesville Region
Indicated change in oil production (Aug vs. Jul)

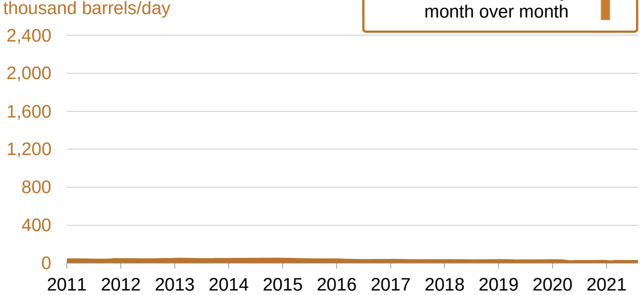


Haynesville Region
Indicated change in natural gas production (Aug vs. Jul)



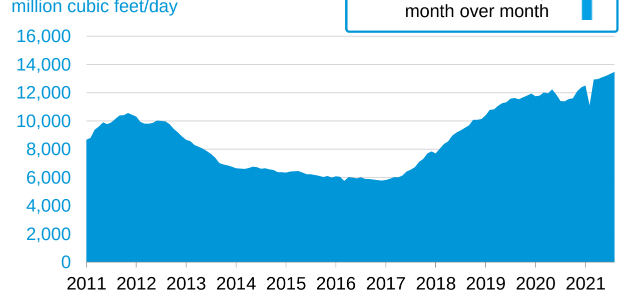
Haynesville Region
Oil production

Oil +0
thousand barrels/day
month over month



Haynesville Region
Natural gas production

Gas +145
million cubic feet/day
month over month



Niobrara Region

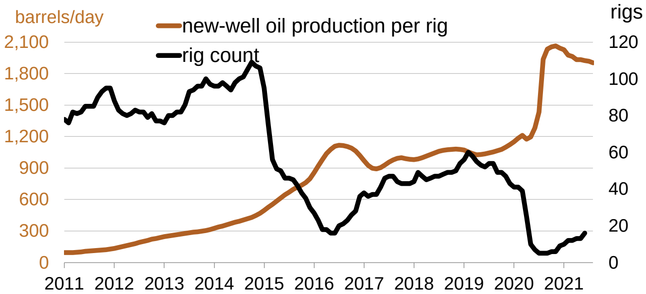
Drilling Productivity Report

July 2021

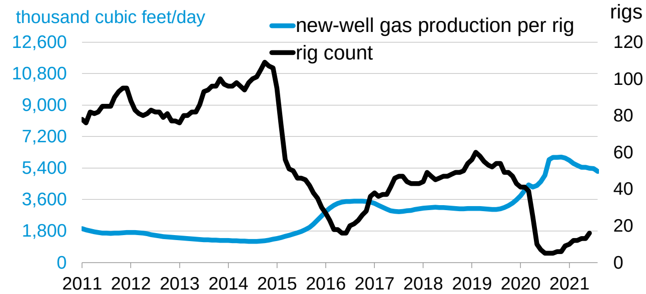
drilling data through June
projected production through August

Oil -17 barrels/day month over month	**1,902** *August* **1,919** *July* barrels/day	**Monthly additions from one average rig**	*August* **5,209** *July* **5,370** thousand cubic feet/day	**Gas -161** thousand cubic feet/day month over month

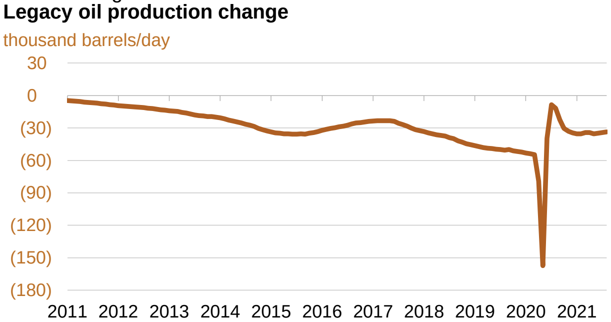
Niobrara Region
New-well oil production per rig



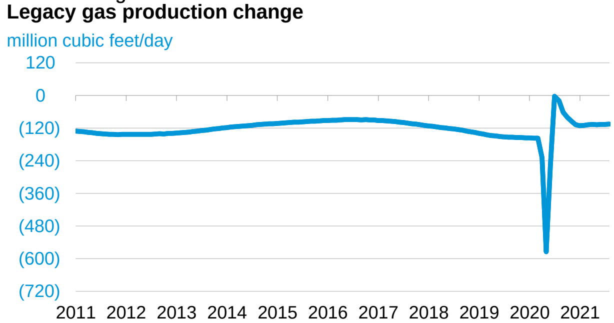
Niobrara Region
New-well gas production per rig



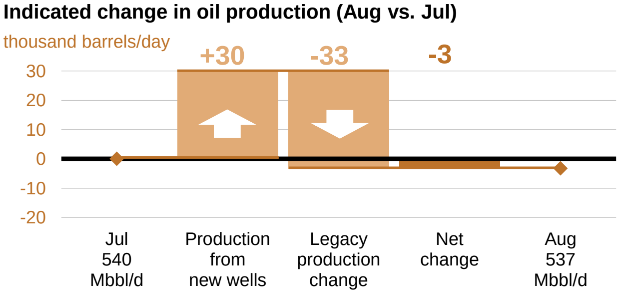
Niobrara Region
Legacy oil production change



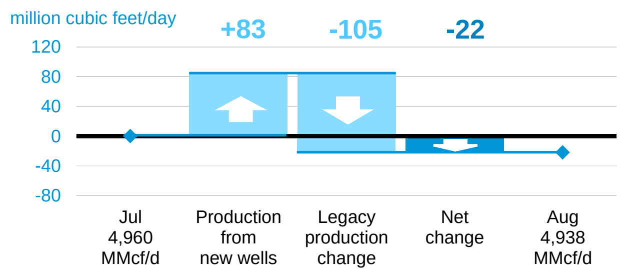
Niobrara Region
Legacy gas production change



Niobrara Region
Indicated change in oil production (Aug vs. Jul)

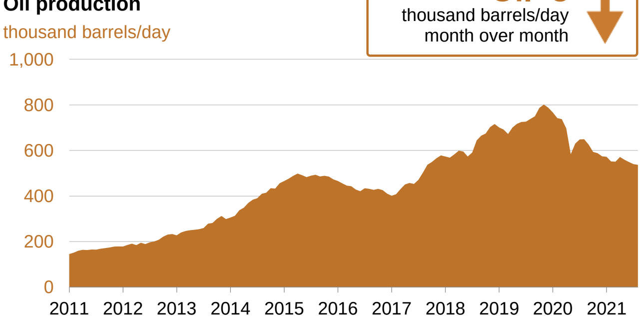


Niobrara Region
Indicated change in natural gas production (Aug vs. Jul)



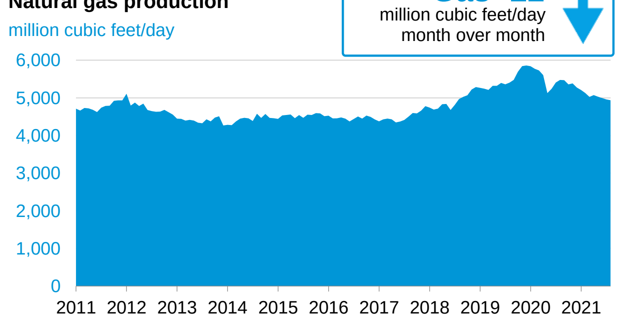
Niobrara Region
Oil production

Oil -3 thousand barrels/day month over month



Niobrara Region
Natural gas production

Gas -22 million cubic feet/day month over month



Permian Region

Drilling Productivity Report

July 2021

drilling data through June
projected production through August

Oil -5
barrels/day
month over month

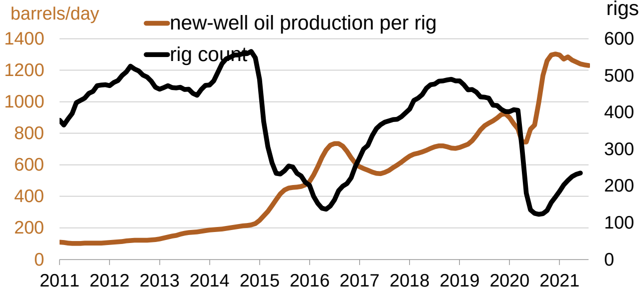
1,229 *August*
1,234 *July*
barrels/day

Monthly additions from one average rig

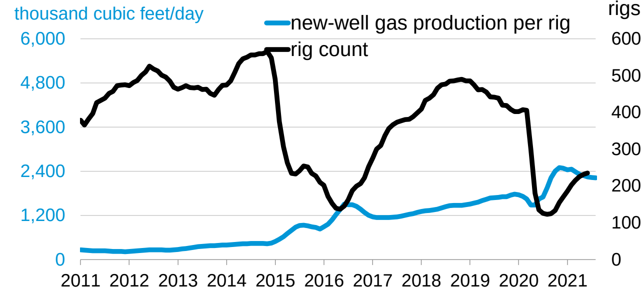
August **2,220**
July **2,231**
thousand cubic feet/day

Gas -11
thousand cubic feet/day
month over month

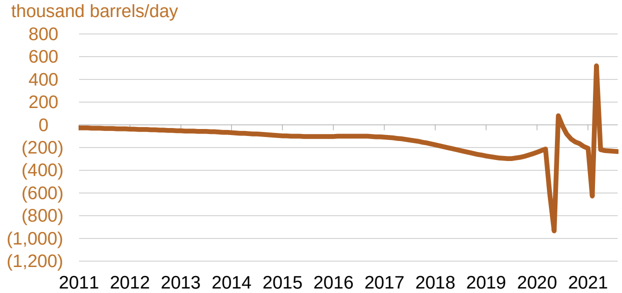
Permian Region
New-well oil production per rig



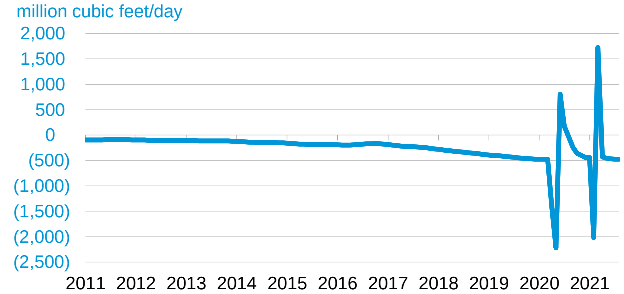
Permian Region
New-well gas production per rig



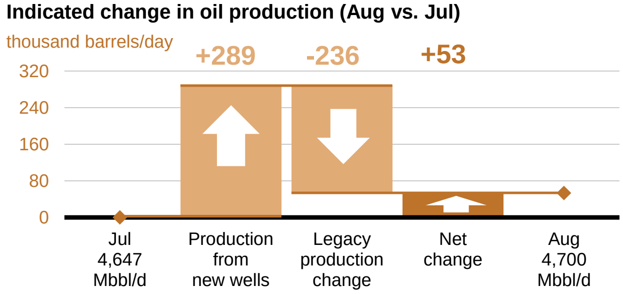
Permian Region
Legacy oil production change



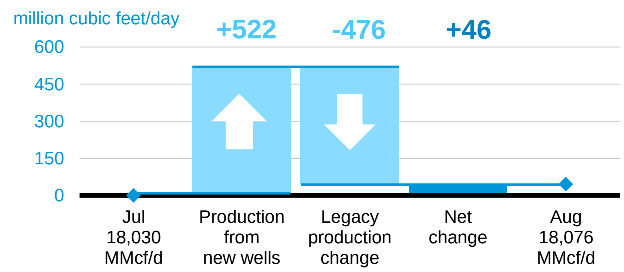
Permian Region
Legacy gas production change



Permian Region
Indicated change in oil production (Aug vs. Jul)

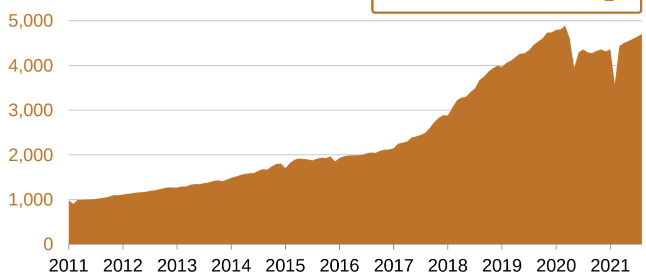


Permian Region
Indicated change in natural gas production (Aug vs. Jul)



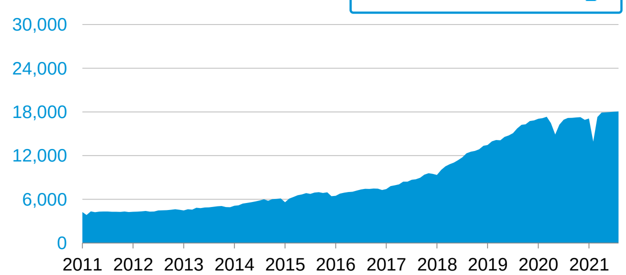
Permian Region
Oil production
thousand barrels/day

Oil +53
thousand barrels/day
month over month



Permian Region
Natural gas production
million cubic feet/day

Gas +46
million cubic feet/day
month over month



The Drilling Productivity Report uses recent data on the total number of drilling rigs in operation along with estimates of drilling productivity and estimated changes in production from existing oil and natural gas wells to provide estimated changes in oil[1] and natural gas[2] production for seven key regions. EIA's approach does not distinguish between oil-directed rigs and gas-directed rigs because once a well is completed it may produce both oil and gas; more than half of the wells do that.

Monthly additions from one average rig

Monthly additions from one average rig represent EIA's estimate of an average rig's[3] contribution to production of oil and natural gas from new wells.[4] The estimation of new-well production per rig uses several months of recent historical data on total production from new wells for each field divided by the region's monthly rig count, lagged by two months.[5] Current- and next-month values are listed on the top header. The month-over-month change is listed alongside, with +/- signs and color-coded arrows to highlight the growth or decline in oil (brown) or natural gas (blue).

New-well oil/gas production per rig

Charts present historical estimated monthly additions from one average rig coupled with the number of total drilling rigs as reported by Baker Hughes.

Legacy oil and natural gas production change

Charts present EIA's estimates of total oil and gas production changes from all the wells other than the new wells. The trend is dominated by the well depletion rates, but other circumstances can influence the direction of the change. For example, well freeze-offs or hurricanes can cause production to significantly decline in any given month, resulting in a production increase the next month when production simply returns to normal levels.

Projected change in monthly oil/gas production

Charts present the combined effects of new-well production and changes to legacy production. Total new-well production is offset by the anticipated change in legacy production to derive the net change in production. The estimated change in production does not reflect external circumstances that can affect the actual rates, such as infrastructure constraints, bad weather, or shut-ins based on environmental or economic issues.

Oil/gas production

Charts present all oil and natural gas production from both new and legacy wells since 2007. This production is based on all wells reported to the state oil and gas agencies. Where state data are not immediately available, EIA estimates the production based on estimated changes in new-well oil/gas production and the corresponding legacy change.

Footnotes:

1. Oil production represents both crude and condensate production from all formations in the region. Production is not limited to tight formations. The regions are defined by all selected counties, which include areas outside of tight oil formations.
2. Gas production represents gross (before processing) gas production from all formations in the region. Production is not limited to shale formations. The regions are defined by all selected counties, which include areas outside of shale formations.
3. The monthly average rig count used in this report is calculated from weekly data on total oil and gas rigs reported by Baker Hughes.
4. A new well is defined as one that began producing for the first time in the previous month. Each well belongs to the new-well category for only one month. Reworked and recompleted wells are excluded from the calculation.
5. Rig count data lag production data because EIA has observed that the best predictor of the number of new wells beginning production in a given month is the count of rigs in operation two months earlier.

The data used in the preparation of this report come from the following sources. EIA is solely responsible for the analysis, calculations, and conclusions.

Drilling Info (http://www.drillinginfo.com) Source of production, permit, and spud data for counties associated with this report. Source of real-time rig location to estimate new wells spudded and completed throughout the United States.

Baker Hughes (http://www.bakerhughes.com) Source of rig and well counts by county, state, and basin.

North Dakota Oil and Gas Division (https://www.dmr.nd.gov/oilgas) Source of well production, permit, and completion data in the counties associated with this report in North Dakota

Railroad Commission of Texas (http://www.rrc.state.tx.us) Source of well production, permit, and completion data in the counties associated with this report in Texas

Pennsylvania Department of Environmental Protection (https://www.paoilandgasreporting.state.pa.us/publicreports/Modules/Welcome/Welcome.aspx) Source of well production, permit, and completion data in the counties associated with this report in Pennsylvania

West Virginia Department of Environmental Protection (http://www.dep.wv.gov/oil-and-gas/Pages/default.aspx) Source of well production, permit, and completion data in the counties associated with this report in West Virginia

Colorado Oil and Gas Conservation Commission (http://cogcc.state.co.us) Source of well production, permit, and completion data in the counties associated with this report in Colorado

Wyoming Oil and Conservation Commission (http://wogcc.state.wy.us) Source of well production, permit, and completion data in the counties associated with this report in Wyoming

Louisiana Department of Natural Resources (http://dnr.louisiana.gov) Source of well production, permit, and completion data in the counties associated with this report in Louisiana

Ohio Department of Natural Resources (http://oilandgas.ohiodnr.gov) Source of well production, permit, and completion data in the counties associated with this report in Ohio

Oklahoma Corporation Commission (http://www.occeweb.com/og/oghome.htm) Source of well production, permit, and completion data in the counties associated with this report in Oklahoma https://rbnenergy.com/better-days-us-lng-feedgas-rebounds-as-spring-maintenance-season-rolls-off

Better Days - U.S. LNG Feedgas Rebounds As Spring Maintenance Season Rolls Off

Sunday, 07/11/2021
Published by: Lindsay Schneider

Global gas prices have had a record-breaking year so far, with JKM in Asia hitting all-time seasonal highs in spring, and TTF in Europe last week reaching the highest level since 2008. Prices have been spurred on by a global LNG market that is undersupplied and hunting for additional cargoes. If you were just looking at U.S. feedgas levels over the past several weeks, though, you would never know that we are in the middle of an incredible bull run. U.S. LNG feedgas deliveries have trailed below full-utilization levels for more than a month due to a combination of spring pipeline maintenance, LNG terminal maintenance, and operational issues. The reduced availability of pipeline and liquefaction capacity led feedgas deliveries in June to average 9.35 Bcf/d, or about 85% of full capacity. However, this was just a small and short-lived setback before what is likely to be a breakthrough summer for U.S. LNG. Feedgas demand is already back above 95% utilization and is poised to head even higher over the next few months both from new liquefaction capacity coming online and potentially from spot market cargo production. In today's blog, we take a look at the impact of spring maintenance on U.S. LNG production and potential feedgas demand growth in the months ahead.

Prior to the COVID-19 pandemic and the subsequent global market crash, U.S. LNG facilities operated mostly at their contracted capacity. Feedgas for LNG exports steadily ramped up from zero in early 2016 to just above 9 Bcf/d in early 2020, with feedgas demand increasing with each new liquefaction train that came online and only deviating to the downside when operational issues or maintenance reduced capacity or to the upside in order to produce the occasional spot market cargo. In April 2020, however, with winter demand subsiding, COVID lockdowns spreading worldwide with no end in sight, and global gas prices nearing rock bottom, offtakers began canceling cargoes from U.S. LNG plants. Just about every Gulf Coast LNG terminal had to pare back operations and partially shut-in production, which sent feedgas plummeting even as new capacity came online (See LNG Interruption and Sultans of Swing for more). Figure 1 below shows the growth in daily feedgas volume (orange line) compared with the estimated feedgas requirement at full-contracted capacity at all the operating Lower-48 terminals combined (black line). As you can see below, prior to the pandemic, feedgas tracked the capacity line closely. However, cargo cancellations curtailed feedgas demand from April to October last year (dashed blue oval), peaking in July and August. At the same time, more than 10 MMtpa or nearly 1.4 Bcf/d of new LNG capacity ramped up as Freeport, Cameron and Elba all brought new trains online during the six-month period that saw the cargo cancellations.

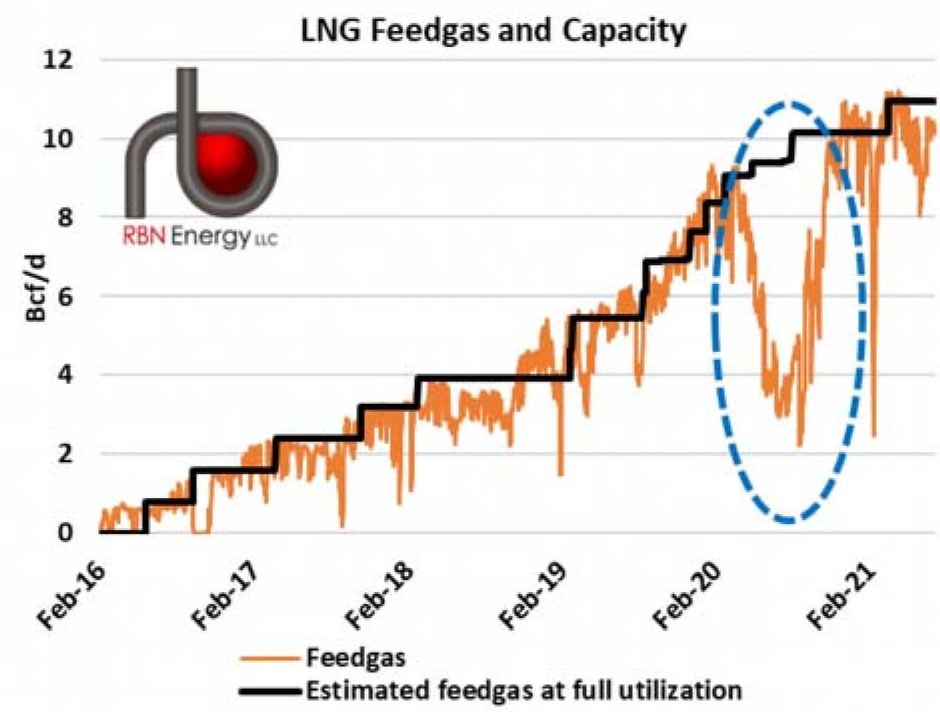


Figure 1. LNG Feedgas and Capacity at Full Utilization. Source: RBN LNG Voyager

The new capacity additions set feedgas demand up for a startling recovery once cargo cancellations finally subsided in October. By then, economic cancellations had waned from their summer peaks, but a record-breaking hurricane season through late summer and fall reduced feedgas deliveries for some time after cancellations began easing. Storms impacted U.S. terminal production from August through early November and delayed what could otherwise have been a fall recovery from the summer cargo cancellations. Feedgas averaged just 3.3 Bcf/d in July and by November had climbed to 9.6 Bcf/d, a new record level, although one that couldn't hold on for long. Feedgas demand climbed even higher in the winter as Corpus Christi Train 3 began commissioning (see Such Great Heights). In February this year, Winter Storm Uri forced most of the U.S. terminals to shut-in for at least a few days, depressing feedgas flows to well below capacity for about two weeks while the Gulf Coast dealt with extreme cold weather (see Feed Me). But feedgas demand bounced back and then some after that, hitting new record highs as Corpus Christi Train 3 came online in late March.

With new capacity online and absolutely no talk of cargo cancellations, feedgas this April averaged more than 10.75 Bcf/d. Global prices continued to soar as European storage was struggling (and still is) to refill inventories, cold weather lingered, and COVID lockdowns were mostly over (see Summertime for more on global prices), setting the U.S. up for potentially robust exports this spring/early summer. But pipeline maintenance, some terminal maintenance, and operational issues noticeably limited feedgas flows in May, when it averaged 10.2 Bcf/d, and in June when it was just 9.35 Bcf/d — the lowest level since October 2020, excluding the shut-ins due to Winter Storm Uri. These maintenance-related disruptions were a temporary setback and a normal part of the gas market, however, and they are now already in the rearview mirror of what still will be a big summer for U.S. LNG.

Gas pipelines typically carry out maintenance during the shoulder months in the spring and fall. This is designed to cause minimal disruption to gas customers by taking advantage of the times when domestic demand is lower. However, the U.S. LNG market doesn't have any lower demand times, barring last year's cargo cancellations. So, LNG terminals will feel the impact of the maintenance season more strongly than the average residential or commercial customer. Most maintenance and testing done during this time has little prolonged impact on gas flow. However, this spring, there were a few longer outages either from more extensive work that needed to be done or because of issues uncovered during the regular tuning process, and these impacted LNG feedgas at Corpus Christi and Sabine Pass in particular this year. Figure 2 below, shows daily feedgas by terminal to highlight the impact of maintenance and operational issues on LNG the past few months.

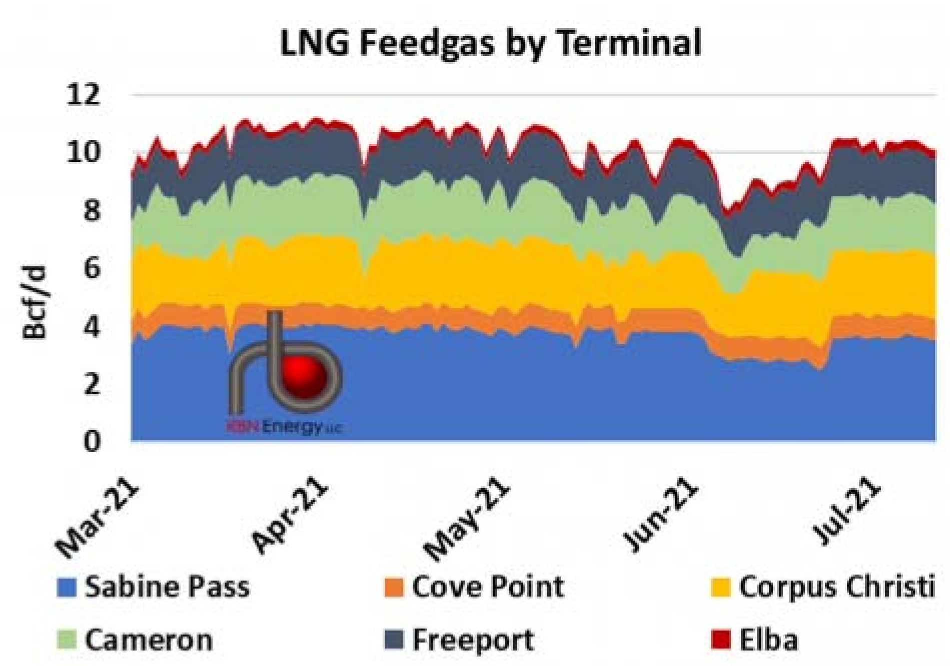


Figure 2. LNG Feedgas by Terminal. Source: RBN LNG Voyager

Corpus Christi feedgas (yellow layer in Figure 2) was reduced from May 14 to June 10, in part due to maintenance on the Transco Pipeline, but mostly driven by a force majeure event on the Natural Gas Pipeline of America (NGPL) that began on May 18 and was caused by horsepower issues at a compressor station in Victoria County, TX. The force majeure was lifted on June 6, and a few days later, feedgas flows to Corpus Christi were back to levels consistent with full utilization, where it has been since then.

Sabine Pass (blue layer in Figure 2) had its feedgas supply reduced from June 4 to June 24 because of maintenance on Transco and the Creole Trail Pipeline. Transco conducted extensive maintenance work in Louisiana this year, which curtailed flows to Sabine Pass. The work, which ran from June 4 to June 18, was concentrated on the Southwest Louisiana (SWLA) lateral and compressor station 45 located on the mainline in southern Louisiana. Flows from Transco to Sabine Pass were reduced by between about 450 and 700 MMcf/d during the maintenance. Just as work on Transco was drawing to an end, Creole Trail began electrical upgrades, causing reduced flows to the terminal and offsetting the rebound in Transco flows. The upgrades were completed on June 22 and then followed by a half-day of compressor maintenance on June 23. Feedgas from Creole Trail varies daily but is typically around 1.35 Bcf/d when the terminal is operating at full capacity. Flows during the first three days of maintenance slumped below 500 MMcf/d and then recovered to around 1 Bcf/d after that.

In addition to pipeline maintenance, LNG terminals also conduct periodic maintenance in the spring and fall. LNG train maintenance is often not publicized in advance, with the exception of Cove Point, which typically conducts maintenance on its single train every year in October. This spring, **Cameron** (green area in Figure 2) conducted maintenance on one of its trains, thought to be Train 3, although that was not confirmed by Sempra (Cameron's terminal operator). Feedgas to the terminal averaged around 1.2 Bcf/d between June 7 and June 18, about 800 MMcf/d shy of typical full utilization.

The other three terminals — Cove Point, Elba, and Freeport — have not had any prolonged maintenance events that caused significant deviations from typical full utilization feedgas levels. All three of the terminals, however, do have unique issues of note in their operations. **Elba's Unit 2** has been offline ever since a fire broke out in May 2020. Terminal operator Kinder Morgan said in early April (2021) that a repair plan was in place for Unit 2, and it hoped to restore service in the fourth quarter of this year, depending on the arrival of the equipment needed from its vendors. No updates have been provided since then, but in recent days, Elba feedgas flows (red layer in Figure 2) have been inching up and there have been multiple days where it appeared that Unit 2 was potentially taking feedgas. This has not been confirmed by Kinder Morgan, however, and feedgas is currently at a level consistent with nine out of 10 units in operation.

Freeport (dark blue layer in Figure 2) has not had any lengthy outages. However, the brief-but-frequent feedgas flow disruptions and filings with the Texas Commission on Environmental Quality (TCEQ) indicate there are clearly ongoing issues with its interconnection to the ERCOT electrical grid. Freeport had eight unplanned restarts of individual or multiple liquefaction trains in June most of which were caused by electrical or voltage issues. Freeport is the only U.S. terminal experiencing these types of shut-downs, likely because it is the only one using all-electric compressors to power its liquefaction process and it is also the only U.S. terminal to buy its electricity from a deregulated power market. The other U.S. terminals use either gas or a combination of gas and electricity in the liquefaction process. Others that buy electricity as well, like Cameron, do so directly from a regulated utility rather than from the grid. The most recent trip at Freeport happened on June 29. Most of the incidents have been caused by a power surge leading to one or more of the trains going offline, causing unplanned gas flaring, which then has to be reported to the TCEQ. The restarts almost always happen the same day as the incident, and feedgas is usually only reduced for one or two days. Despite the operational issues, Freeport has mostly been able to maintain its cargo output this month by taking higher levels of feedgas when it is able to.

Finally, at **Cove Point** (orange layer in Figure 2), feedgas flows have been remarkably strong for the past two months, exceeding the facility's contracted capacity and typical flow volumes for this time of year by about 10% from May 1 until June 29. Given the high global prices and consistently high feedgas levels, Cove Point most likely produced two additional cargoes for the spot market over that period. With only a single production train operating, it takes Cove Point about a month to take in the additional feedgas needed to produce a spot market cargo.

While maintenance has been a drag on U.S. feedgas demand this spring, it has remained a net bullish factor for the U.S. gas market, particularly when you compare with last year. In May 2021, feedgas deliveries were nearly 4 Bcf/d higher than in May 2020, and in June, even though feedgas dropped by about 800 MMcf/d month-on-month, it was up 5.35 Bcf/d year-on-year. Every single terminal in the U.S. saw higher levels of feedgas this spring compared with last spring. Pipeline and LNG terminal maintenance is a normal part of gas market operations, and while exact impacts will vary from season to season and year to year, the spring and fall are always going to be subject to some supply curtailments from maintenance, not to mention operational issues and force majeure events, which can occur at any time.

Maintenance events aside, we are in the middle of a decidedly bullish period for U.S. LNG. Global gas prices remain strong. So far this spring and summer, every time prices take a step back, they rally dramatically soon after. Just last week, prices in Europe fell from the record-breaking mid-$12/MMBtu level to the low $11/MMBtu, but then rallied by more than $1/MMBtu on Friday to close out the week at another new post-2008 high. What's more, low storage inventories in Europe, coupled with strong global demand — which is making it extremely difficult to rebuild those storage inventories — mean that European prices will be well-supported through at least the coming winter.

How strong might exports be? To answer that, let's take a look at the export economics. Figure 3 summarizes regional prices and export costs for U.S. LNG over the past year and for the year ahead, based on the current forward curves. Specifically, the graphs show the JKM and TTF price indices vs. RBN's estimate of the range of marginal costs to deliver to Asia (left graph) and Europe (right graph). We discussed the various components that make up these costs and how they are calculated at great length in our [Sultans of Swing]() blog series and in [Wild Thing](). In short, the marginal cost ranges (shown in blue for deliveries to Asia and orange for deliveries to Europe) represent the high and low estimates for all the marginal costs associated with exporting LNG to Asia or Europe. When destination prices (black line) are above the range, U.S. exports are profitable and economic cancellations are unlikely. When the line is below the range, widespread economic cancellations happen. And when the line is in the middle of the range, some cargoes/terminals clear the marginal cost of exporting and some don't, and some cancellations are likely.

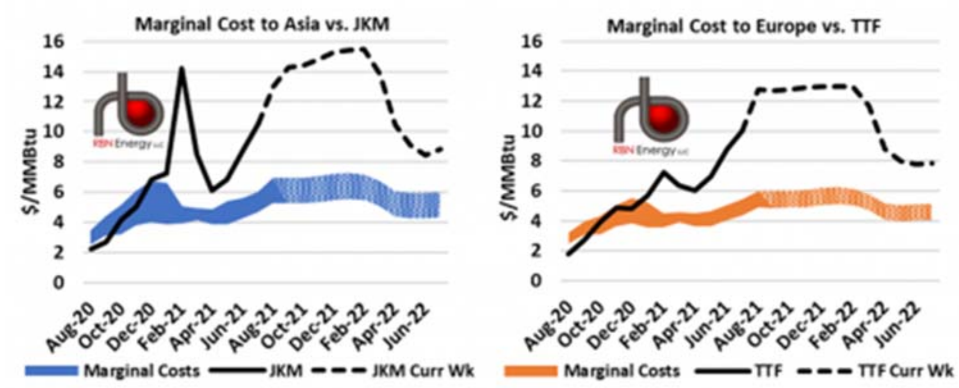


Figure 3. Marginal Cost of U.S. LNG Exports vs. Global Prices. Source: [RBN LNG Voyager]()

As is clear from the graphs in Figure 3, gas prices are strong throughout the forward curve right now, and there is no risk of economic cargo cancellations in sight. Prices are not only well above the marginal cost of exporting but also the full-cycle cost of U.S. LNG, meaning that we may see more production of spot cargoes as pipeline maintenance rolls off heading into the peak summer months. Cove Point has most likely already produced spot cargoes, as we noted above, but other terminals could follow suit, pushing U.S. feedgas to record highs. If that's not enough, new liquefaction capacity is right around the corner that could drive feedgas even higher. Sabine Pass Train 6 received FERC authorization to commission the fuel gas system in late June, and the full liquefaction plant commissioning, along with increased feedgas and first LNG production, will follow in the next few months. Calcasieu Pass should also begin commissioning this summer. With new capacity coming online soon and spot market production on the table, we will almost certainly see new record feedgas levels this summer and continued strength in feedgas demand at least until the next maintenance period in the fall.

For regular updates on feedgas, terminal operations, and export economics please check out our LNG Voyager report [here]().

"Better Days" was written by Bruce Springsteen and is the first song on Springsteen's 10th studio album, *Lucky Town.* Released as the first single from the album in March 1992, the song went to #16 on the Billboard Hot 100 Singles chart. Personnel on the record were: Bruce Springsteen (lead vocals, guitar, keyboards, harmonica, percussion), Gary Mallaber (drums), Randy Jackson (bass), and Patti Scialfa, Soozie Tyrell, Lisa Lowell (backing vocals).

Lucky Town was recorded between September 1991 and January 1992 at Thrill Hill Recording and A&M Studios in Los Angeles. Produced by Springsteen, along with Jon Landau, Chuck Plotkin, and Roy Bittan, the album was released simultaneously with the LP *Human Touch* in March 1992. Springsteen had been working on *Human Touch* since 1990, and when he had written and recorded

10 new songs since wrapping up the LP, he decided to release two new albums at the same time. *Lucky Town* is a more personal, stripped-down folksy record than *Human Touch*. *Lucky Town* went to #3 on the Billboard Top 200 Albums chart and has been certified Platinum by the Recording Industry Association of America (RIAA). *Human Touch* went to #2 on the Billboard Top 200 chart. It too was certified Platinum by the RIAA. Four singles were released from *Lucky Town*, three from *Human Touch*.

Bruce Springsteen is an American singer, songwriter, and musician. He has released 20 studio albums, 23 live albums, eight compilation albums, one soundtrack album, seven EPs, and 73 singles. He has sold more than 135 million records worldwide. He has earned 20 Grammy Awards, two Golden Globes, one Academy Award, and one Tony Award. Springsteen is a member of the Rock and Roll Hall of Fame and the Songwriters Hall of Fame. He has received Kennedy Center Honors, the Presidential Medal of Freedom, and a Woody Guthrie Prize. Springsteen continues to record and tour.

https://lngir.cheniere.com/news-events/press-releases/detail/224/cheniere-corpus-christi-stage-iii-and-tourmaline-sign

Cheniere Corpus Christi Stage III and Tourmaline Sign Long-Term Gas Supply Agreement

Download as PDFJULY 15, 2021 5:02PM EDT

HOUSTON--(BUSINESS WIRE)-- Cheniere Energy, Inc. ("Cheniere") (NYSE American: LNG) announced today that its subsidiary, Corpus Christi Liquefaction Stage III, LLC ("Corpus Christi Stage III"), has entered into a long-term gas supply agreement ("GSA") with Tourmaline Oil Marketing Corp. ("Tourmaline"), a subsidiary of Tourmaline Oil Corp. (TSX: TOU), the largest natural gas producer in Canada.

Under the GSA, Tourmaline has agreed to sell 140,000 MMBtu per day of natural gas to Corpus Christi Stage III for a term of 15 years beginning in early 2023. The LNG associated with this gas supply, approximately 0.85 million tonnes per annum ("mtpa"), will be marketed by Cheniere. Cheniere will pay Tourmaline an LNG-linked price for its gas, based on the Platts Japan Korea Marker (JKM), after deductions for fixed LNG shipping costs and a fixed liquefaction fee. Tourmaline Oil Corp. is acting as guarantor of the GSA on behalf of Tourmaline. This Integrated Production Marketing (IPM) transaction is expected to support the development of the Corpus Christi Stage III project.

"This latest IPM agreement with Canada's largest natural gas producer demonstrates the breadth of Cheniere's natural gas resource supply and the range of our commercial options," said Jack Fusco, Cheniere's President and CEO. "This commercial agreement is expected to support our shovel-ready Corpus Christi Stage III project while enabling Canadian natural gas to reach international LNG markets. Additionally, it reinforces Cheniere's track record of creating collaborative, innovative solutions to meet customers' needs and supports Cheniere's growth."

"Our long-term supply agreement with Cheniere is the next important step in Tourmaline Oil Corp's evolving market diversification strategy. We are pleased to be supplying low emission Canadian natural gas with Cheniere to growing international markets," said Mike Rose, Tourmaline Oil Corp's President and CEO.

The Corpus Christi Stage III project is being developed to include up to seven midscale liquefaction trains with a total expected nominal production capacity of approximately 10 mtpa. It has received all necessary regulatory approvals.

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 March 31, 2021, filed with the Securities and Exchange Commission.

Forward-Looking Statements

This press release contains certain statements that may include "forward-looking statements" within the meanings of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. All statements, other than statements of historical or present facts or conditions, included herein are "forward-looking statements." Included among "forward-looking statements" are, among other things, (i) statements regarding Cheniere's financial and operational guidance, business strategy, plans and objectives, including the development, construction and operation of liquefaction facilities, (ii) statements regarding expectations regarding regulatory authorizations and approvals, (iii) statements expressing beliefs and expectations regarding the development of Cheniere's LNG terminal and pipeline businesses, including liquefaction facilities, (iv) statements regarding the business operations and prospects of third parties, (v) statements regarding potential financing arrangements, (vi) statements regarding future discussions and entry into contracts, (vii) statements relating to the amount and timing of share repurchases, and (viii) statements regarding the COVID-19 pandemic and its impact on our business and operating results. Although Cheniere believes that the expectations reflected in these forward-looking statements are reasonable, they do involve assumptions, risks and uncertainties, and these expectations may prove to be incorrect. Cheniere's actual results could differ materially from those anticipated in these forward-looking statements as a result of a variety of factors, including those discussed in Cheniere's periodic reports that are filed with and available from the Securities and Exchange Commission. You should not place undue reliance on these forward-looking statements, which speak only as of the date of this press release. Other than as required under the securities laws, Cheniere does not assume a duty to update these forward-looking statements.

Investors
Randy Bhatia, 713-375-5479

https://www.newswire.ca/news-releases/tourmaline-announces-closing-of-black-swan-energy-acquisition-and-a-new-long-term-gas-supply-agreement-with-cheniere-energy-843605829.html

Tourmaline Announces Closing of Black Swan Energy Acquisition and a New Long-Term Gas Supply Agreement with Cheniere Energy

NEWS PROVIDED BY
Tourmaline Oil Corp.

Jul 15, 2021, 17:00 ET

CALGARY, AB, July 15, 2021 /CNW/ - Tourmaline Oil Corp. (TSX: TOU) ("Tourmaline" or the "Company") is pleased to announce the closing of two strategic North Montney transactions, a North Montney GORR transaction with Topaz Energy Corp. ("Topaz") and a significant long-term gas supply agreement with Cheniere Energy, Inc. ("Cheniere").

BLACK SWAN ENERGY CLOSING

- Tourmaline is pleased to announce the closing of its acquisition of Black Swan Energy Ltd. ("Black Swan").
- Tourmaline will complete the ongoing Nig Creek plant expansion, bringing production from the Black Swan assets to 60,000 boepd early in Q2 2022.
- With the closing of the Black Swan acquisition, Tourmaline is currently producing 465,000–475,000 boepd.
- Tourmaline expects to reach the 500,000 boepd production milestone during Q2 of 2022 and, at approximately 105,000 bpd, has exceeded the 100,000-bpd liquid production milestone (oil, condensate, NGLs).

PARAMOUNT BIRCH

- Tourmaline has acquired Paramount Resources Ltd.'s ("Paramount") lands and assets in the Birch area of the North Montney trend. The acquired assets include 2,400 boepd of current production from 15 Montney horizontals, 2P reserves of 40 mmboe[(1)], and an estimated 105 future Tier 1 locations for total consideration of approximately $88 million before customary closing adjustments.

- The Birch transaction completes the consolidation of key available assets along the future eastern leg of planned Tourmaline infrastructure and lies in immediate proximity to the Black Swan lands.

- These are Tier 1 Montney assets, with EUR, deliverability and economics similar to the Black Swan inventory (8 - 10 bcf, 400 - 500 mbbl/well).

TOPAZ TRANSACTIONS

- Tourmaline closed the previously announced NEBC Montney GORR and infrastructure transaction with Topaz on July 1, 2021, receiving $245 million of cash proceeds.

- Tourmaline has also entered into an agreement with Topaz on the Black Swan and Paramount Birch assets in NEBC, whereby Tourmaline will grant a GORR to Topaz (4% on gas for 2021-2023, reducing to 3% in 2024, 2.5% on condensate) in exchange for cash consideration of $145 million. The closing is scheduled for August 3, 2021.

- Topaz, which was created in part to facilitate participation in the recognized developing generational M&A opportunities in 2H 2019, has provided Tourmaline with $573 million of cash proceeds through GORR and select infrastructure drop down transactions in the 2020 / 2021 timeframe.

- Topaz has, in part, allowed Tourmaline to execute on its consolidation strategy while continuing to deleverage its balance sheet. Tourmaline's net debt[2] at September 30, 2019, was $1.9 billion; the estimated net debt at year-end 2021 is $1.3 billion[3]. Comparing Q4 2021[4] to Q3 2019, quarterly production will have grown by 64%, cash flow[5] by greater than 200%, and free cash flow ("FCF")[6] by greater than $300 million. Debt to cash flow will drop from 2.1 times in mid-2019 to 0.5 times by exit 2021.

CONSOLIDATION / FUTURE M&A

- Tourmaline's two-year consolidation initiative in the Alberta Deep Basin and BC Montney complexes is now essentially complete.

- The Company may pursue smaller asset deals or land purchases of a non-material nature, likely in 2022. There are currently no further large transactions planned.

- Tourmaline's focus will now shift to achieving the envisaged synergies and enhanced FCF opportunities from the numerous assets acquired over the last 18 months. Continued reduction in cash costs[7] and Tourmaline's lower drill/complete capital costs are the key vehicles for accelerating this FCF generation.

- Tourmaline has embarked upon a comprehensive internal margin improvement initiative to reduce all elements of the cash cost equation. Each $1.00/boe of margin improvement will yield approximately $180 million of annual FCF in 2022. Given the very low staff levels that the Company has always maintained (currently 250 head office employees), staff reductions are not part of this initiative.

FREE CASH FLOW LOOK-BACK / KEY SCREENING CRITERIA

- Tourmaline's key screening criteria for M&A activities has been that the acquired assets or companies must generate FCF within 12 months of acquisition and a FCF yield comparable to or better than that delivered by the ongoing five-year EP organic growth plan.

- The 2020 M&A strategy involved four corporate acquisitions for total consideration (including assumption of net debt, cash proceeds and issuance of common shares) of $795 million before accounting for Topaz cash proceeds. These four transactions are expected to generate approximately $170 million of FCF in 2021 and approximately $290 million in 2022 at strip pricing[8]. A FCF yield of 21 - 36% vs the organic EP growth plan of 10 - 12% in 2021/2022.

- Including all 2020/2021 transactions, Tourmaline has acquired 1.2 million net acres, 1.4 billion boe net 2P reserves[9], 4,500 gross drilling locations since Q4 2019. These assets are currently producing 157,000 boepd and are expected to generate over $500 million of FCF in 2022.

LONG-TERM LNG EXPORT MARKETING ARRANGEMENT WITH CHENIERE ENERGY

- Tourmaline, Canada's largest natural gas producer, and Cheniere, the largest LNG company in the United States, have entered into a long-term marketing arrangement whereby Tourmaline will supply 140,000 mmbtu per day (approximately 140 mmcfpd) to the Corpus Christi liquefaction terminal for a 15-year term commencing in January 2023.

- The LNG Netback Supply Arrangement provides international price exposure to JKM ("Platts Japan-Korea Marker") for Tourmaline, for effectively one cargo per month. JKM is currently trading at approximately US$12.98/mmbtu.

- Tourmaline has secured long-term firm transportation with TC Energy Corporation on existing pipeline systems for total tolls of US$0.86/mmbtu, allowing Tourmaline's low-emission natural gas from the Company's Alberta Deep Basin or BC Montney complexes to access Asian LNG market pricing while further diversifying Tourmaline's sales points for natural gas.

NORMAL COURSE ISSUER BID

- Tourmaline is also pleased to announce that the Toronto Stock Exchange (the "TSX") has approved the renewal of Tourmaline's normal course issuer bid (the "NCIB").

- The NCIB allows Tourmaline to purchase up to 14,943,420 common shares (representing 5% of its 298,868,400 outstanding common shares as of July 9, 2021) over a period of twelve months commencing on July 20, 2021. The NCIB will expire no later than July 19, 2022. Under the NCIB, common shares may be repurchased in open market transactions on the TSX and other alternative trading platforms in Canada and in accordance with the rules of the TSX governing NCIB's. The total number of common shares Tourmaline is permitted to purchase is subject to a daily purchase limit of 349,086 common shares, representing 25% of the average daily trading volume of 1,396,344 common shares on the TSX calculated for the six-month period ended June 30, 2021, however, Tourmaline may make one block purchase per calendar week which exceeds the daily repurchase restrictions. Any common shares that are purchased under the NCIB will be cancelled upon their purchase by Tourmaline.

- Under its most recent normal course issuer bid, Tourmaline obtained approval to purchase up to 13,538,778 of its common shares, of which Tourmaline made no purchases.

- Tourmaline believes that at times, the prevailing share price does not reflect the underlying value of the common shares and the repurchase of its common shares for cancellation may represent an attractive opportunity to enhance Tourmaline's per share metrics and thereby increase the underlying value of its common shares to its shareholders. Tourmaline may use the NCIB as another tool to enhance total long-term shareholder returns and may be used in conjunction with management's disciplined free funds flow capital allocation strategy.

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(1) Reserves have been internally estimated by qualified reserve engineers.
(2) "Net debt" is defined as bank debt and senior unsecured notes plus working capital deficit (adjusted for the fair value of financial instruments, short-term lease liabilities, short-term decommissioning obligations and unrealized foreign exchange in working capital deficit). See "Non-GAAP Financial Measures" in this news release and in the Company's Q1 2021 Management's Discussion and Analysis.
(3) Based on net debt of $1.4 billion as forecast in the Five-Year Plan Guidance released on June 11, 2021 and pro forma the August 3, 2021 proceeds of $145 million from Topaz and the $45 million paid to Paramount in connection with the purchase of Birch area assets.
(4) Based on Five-Year Plan Guidance released on June 11, 2021.
(5) "Cash flow" is defined as cash provided by operations before changes in non-cash operating working capital. See "Non-GAAP Financial Measures" in this news release and in the Company's Q1 2021 Management's Discussion and Analysis.
(6) "Free cash flow" or "FCF" is defined as cash flow less total net capital expenditures. Total net capital expenditures is defined as total capital spending before acquisitions and non-core dispositions. Free cash flow is prior to dividend payments. See "Non-GAAP Financial Measures" in this news release and the Company's Q1 2021 Management's Discussion and Analysis.
(7) Cash costs are defined as operating, transportation, general and administrative and financing costs.
(8) Based on oil and gas commodity strip pricing at July 8, 2021.
(9) All but approximately 140 mmboe of the acquired net 2P reserves have been evaluated by GLJ Petroleum Consultants or Deloitte LLP, independent reserve evaluators, as at the respective transaction dates. The remaining 140 mmboe has been internally estimated by qualified reserve engineers.

Reader Advisories

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

<u>One of the reasons why it went under the radar is that major LNG suppliers played stupid on the Mozambique impact.</u> 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".*

<u>There are other LNG supply delays/interruptions beyond Mozambique.</u> 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.*

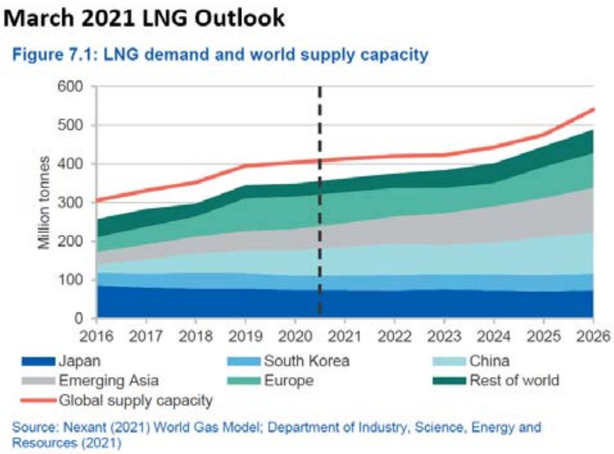
Common theme - new LNG supply is being delayed ie. [Total] Mozambique. Don't forget need capacity>demand due to normal maintenance, etc. Positive for LNG." (ii) Chevron's Gorgon. A big LNG story in H2/20 was the emergence of weld quality issues in the propane heat exchangers at Train 2, which required 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."*

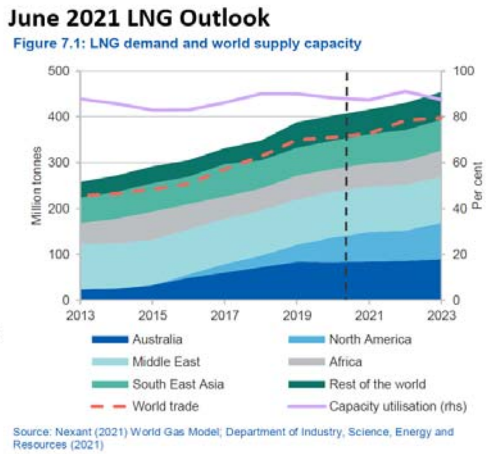
<u>Cheniere stopped the game playing the game on June 30</u>. Our July 4, 2021 Energy Tidbits memo noted that it looks like Cheniere has stopped playing stupid with respect to the strengthening LNG market in 2021. We can't believe they thought they were fooling anyone, especially their competitors. Bu 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



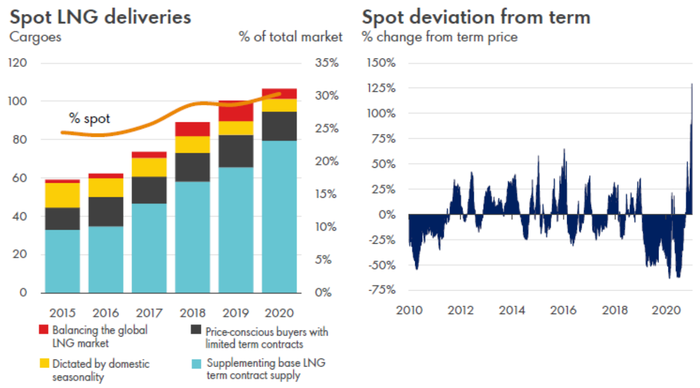


Source: Australia Resources and Energy Quarterly

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.

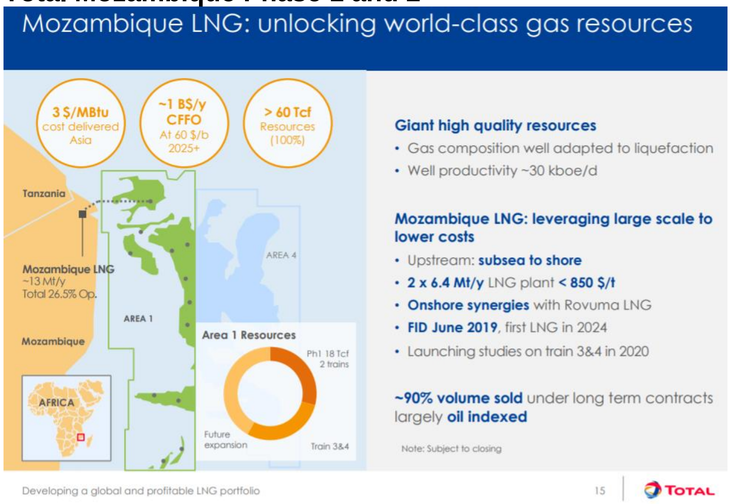
Multiple Brownfield LNG FIDs Now Needed To Fill New LNG Supply Gap From Mozambique Chaos? How About LNG Canada Phase 2?

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



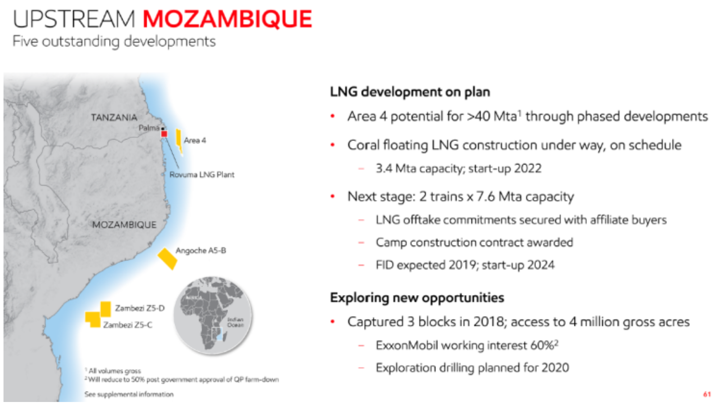
Source: Total Investor Day September 24, 2019

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

<u>Won't LNG and natural gas get hit by Biden's push for carbon free electricity?</u> 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

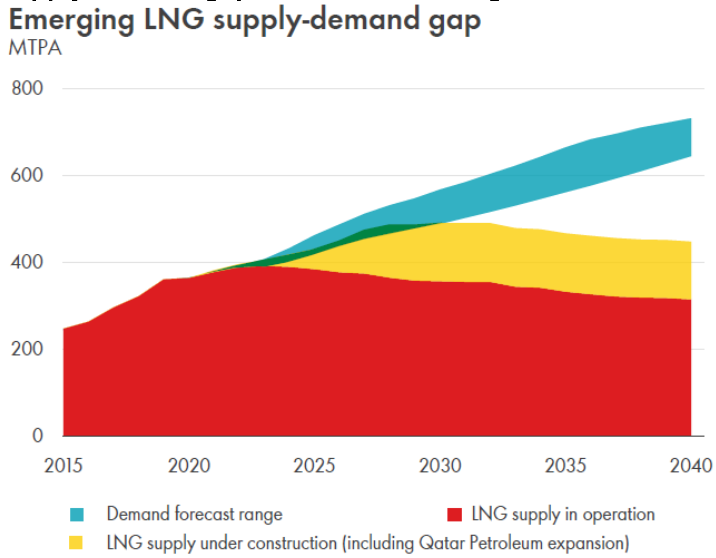
🟢 On Track 🟡 More Efforts Needed 🔴 Not on Track

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.

<u>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?</u> 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

<u>A LNG Canada Phase 2 would be a big plus to Cdn natural gas.</u> 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.

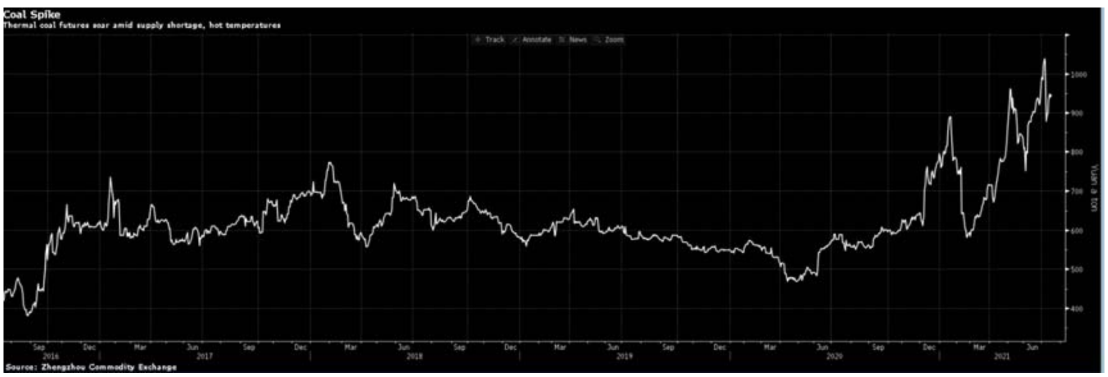
China’s LNG Importers Curb Buying as They Gamble on Price Drop
2021-07-14 05:22:56.429 GMT

By Stephen Stapczynski and Ann Koh
(Bloomberg) -- China’s importers of liquefied natural gas, among the biggest in Asia, have stepped back from the market after spot prices spiked, a move that could leave them vulnerable to a sudden heat wave or supply disruption.
State-owned LNG buyers have curbed activity, with several not planning to buy at all until prices fall at least 10% from current levels, according to traders with knowledge of the strategy. Traders said they would lose money if they purchased spot cargoes at current rates and sold that gas to customers.
End-users from South Korea to India have also balked after spot rates surged to an eight-year seasonal high last month. The moves indicate that Asia’s LNG heavyweights aren’t desperate for cargoes, and are able to eke by on supplies in storage and previously purchased shipments.
Still, extreme temperatures this summer or winter could boost demand and leave utilities flat-footed, forcing them to purchase gas at elevated rates. That would be a repeat of the scenario that played out last winter when bitter cold caught importers unprepared and sent spot rates to a record high.
Chinese end-users have also preferred to purchase pipeline gas, as it has been more affordable than spot LNG. They have also been swapping the timing on LNG shipments within the region in order to optimize supplies.
A step-back from the spot market by Asia could cool the recent price rally for the super-chilled fuel. A global natural gas supply crunch has emerged as a rebound in economic activity and warmer summer weather exacerbates already low storage levels from Louisiana to Germany.
At least two Chinese importers are waiting for spot rates to fall to about $12 per million thermal British units before resuming spot purchases, according to traders, who requested anonymity to discuss private details. The Japan-Korea Marker, the LNG benchmark for North Asia, was trading at the low-$13 per million Btu level on Tuesday.
“Some industrial users, mostly outside of the pipeline grid, may be willing to accept this price level, but the volumes are limited,” said Jenny Yang, a senior director at IHS Markit.
She said the LNG price needs to be $12 or lower to be profitable for traders to sell it into the wholesale market in coastal provinces at current rates.

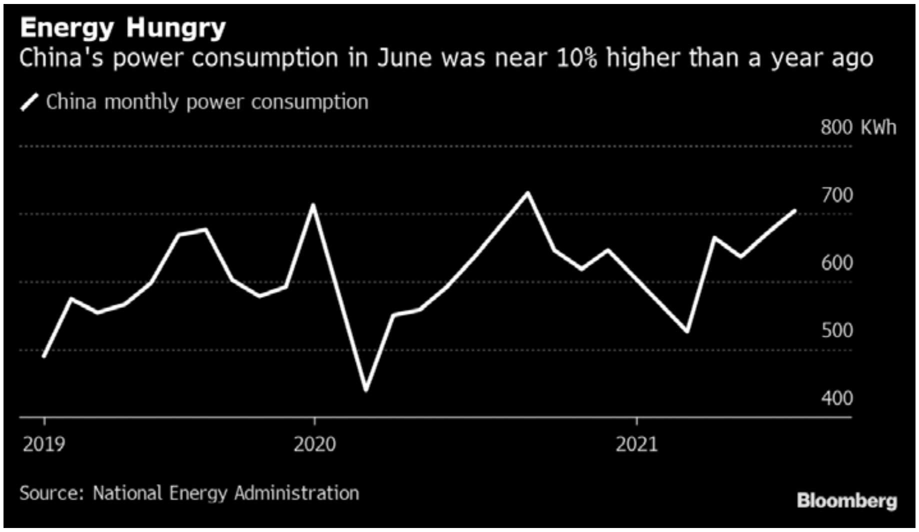
To contact the reporters on this story:
Stephen Stapczynski in Singapore at sstapczynsk1@bloomberg.net;
Ann Koh in Singapore at akoh15@bloomberg.net
To contact the editors responsible for this story:
David Stringer at dstringer3@bloomberg.net
Jeff Sutherland

China’s Heat Wave Is Pushing Coal Prices Toward Record Level (2)
2021-07-16 06:10:14.488 GMT

By Alfred Cang and Krystal Chia
(Bloomberg) -- A heat wave across some of China’s biggest industrial provinces has pushed local electricity consumption to unprecedented levels, sending thermal coal futures toward record highs.
The power load in the eastern province of Zhejiang near Shanghai surpassed 100 million kilowatts per hour on Tuesday for the first time, the State Grid said in its newspaper. Usage has also hit records in nearby Jiangsu and the southern region of Guangdong, where temperatures have reached as high as 37 degrees Celsius (99 degrees Fahrenheit).
The excessive demand boosted Chinese thermal coal futures to the highest in two months, briefly topping 900 yuan a ton in early trading Friday. Futures have rallied more than 30% this year, reaching a record in May, amid a supply shortage.



Coal, China’s principal energy source, has been in short supply as a trade spat with producer Australia has crimped imports, while a spate of fatal accidents has led to safety inspections. At the same time, China’s efforts to limit the use of the dirtiest fossil fuel have been thwarted as hot weather raises air conditioning needs.
It’s Not Over Yet for Coal as Global Prices Surge on Hot Demand
“Southern China has been very hot, and the daily power load is consistently breaking new highs,” said Huatai Futures Co. analyst Wang Haitao. “Although the supply of coal has increased, that’s hard to sustain given the intense draw-down. Some regions are again rationing electricity and issuing warnings about using coal.”
Pressure on the nation’s electricity sources is resurfacing with the onset of summer, which meteorologists have said may be hotter than usual this year. Compounding the problem is China’s strong economic growth as factories return to full strength after the pandemic. Power consumption surged 10% in June.



Authorities have tried several measures to ease the situation. Among the biggest was the plan Thursday to supply 10 million tons of the fossil fuel from reserves, the fifth release of stockpiles this year, according to the Xinhua New Agency. China's top economic planner on Friday vowed a massive buildup of capacity to meet demand and cool prices. China has also considered price caps. But any efforts to boost production at local mines will take time, and the spot market remains especially tight.

Zhejiang's peak load is equivalent to almost five times the energy produced by China's largest hydropower station, the Three Gorges. The province is still highly reliant on coal, with only 30% of its power supplied from renewable sources. Jiangsu's energy needs are even higher, with the province expected to have a peak load of 125 million kilowatt per hour this summer.

Local Export Ban

Extreme weather is upsetting the coal market in more ways than just hot temperatures. A rainstorm days ago temporarily halted the road links between major coal sourcing province Shanxi to some neighboring regions. That forced Henan province to ban exporting its own coal production to other areas, the official Securities Times reported.

Henan also ordered coal producers to report their production and inventories to the government on a daily basis to keep track of supplies and demand, the newspaper said. The government's concern followed a record power load in Zhengzhou, its capital city, according to the report.

Other commodities also risk being hit by efforts to keep electricity flowing. Aluminum output is likely to come under further pressure as supply curtailments due to electricity shortages persist. Smelters in the major hub of Yunnan won’t restore production as planned after a new round of power rationing due to the hot weather, according to Mysteel.

--With assistance from Karoline Kan.

To contact the reporters on this story:
Alfred Cang in Singapore at acang@bloomberg.net;
Krystal Chia in Singapore at kchia48@bloomberg.net
To contact the editors responsible for this story:
Anna Kitanaka at akitanaka@bloomberg.net
Jeff Sutherland, Jason Rogers

To view this story in Bloomberg click here:
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Excerpt Bloomberg @TheTerminal transcript

PRESIDENT JOE BIDEN HOLDS A NEWS CONFERENCE WITH GERMAN CHANCELLOR ANGELA MERKEL

JULY 15, 2021

SPEAKERS:
PRESIDENT JOSEPH R. BIDEN JR.

GERMAN CHANCELLOR ANGELA MERKEL

BIDEN:
And while I reread - while I reiterated my concerns about Nordstream 2, Chancellor Merkel and I are absolutely united in our conviction that Russia must not be allowed to use energy as a weapon to coerce or threaten its neighbors.

MERKEL:
We talked about Russia and Ukraine, and in this context also about Nord Stream 2. We've come to different assessments as to what this project entails, but let me say very clearly, our idea is and remains that Ukraine remains a transit country for natural gas, that Ukraine, just as any other country in the world, has a right to territorial sovereignty, which is why we've become engaged and continue to be engaged in the Minsk process. We will being actively acting should Russia not respect this right of Ukraine, that it has as a transit country. So Nord Stream 2 is an additional project and certainly not a project to replace any kind of transit through Ukraine. Anything else would obviously create a lot of tension. And we're also talking about how we can actually make this very clear together.

QUESTION: Thank you very much, Madam Chancellor. Mr. President, allow me if I may to ask a question as it regards Nord Stream to Madam Chancellor. You just said that you would act actively should Russia be in breach of its commitments, for example, interrupt gas transit for Ukraine. What do you mean in concrete terms on (ph) Germany than switch off Nord Stream 2 from the German side and what sort of legal grounds would you be sort of claiming?

Mr. President, you have fought so many years -- the U.S. has fought so many years against Nord Stream 2, now there will be only a few days left until this pipeline comes into operation. Why -- will you allow it to go ahead, to put it in operation or will the people who operate the system actually have to contend with sanctions on the horizon?

MERKEL: Well, Mr. Kunis (ph), as the chancellor, you know that we've worked a lot, not only Germany incidentally, but the whole of the European commission for talking to Russia and Ukraine, negotiating a treaty that ensures until 2023 the gas contract and after that gas deliveries must be possible as well.

That is what I've heard, at least. Let me be very careful here in my wording. And then should that now go ahead, we have a number of instruments at our disposal, which are not necessarily on the German side but on the European side, for example sanctions and as regards Crimea in breach of Minsk Treaty has shown that we have those sanctions -- those instruments at our disposal.

We have possibilities to react. We are in contact with our European friends on this. But at the -- at the point in time of which I hope we will never have to take those decisions; you will then see what we do.

BIDEN: My view on Nord Stream 2 has been known for sometimes. Good friends can disagree and -- but by the time I became president it was 90 percent completed and imposing sanctions did not seem to make any sense. It made more sense to work with the chancellor on finding out how she'd proceed based on whether or not Russia tried to essentially black mail Ukraine in some way. And so the Chancellor and I have asked our teams to look at practical measures we could take together, and whether or not your energy security - Ukraine security are actually strengthened or weakened based on Russian actions. And so this is a - we'll see, we'll see.

(Inaudible).

https://energyworkforce.org/archives/june-employment-report-sector-adds-jobs-for-4th-consecutive-month/

13 JUL 2021
ENERGY WORKFORCE NEWS, INDUSTRY NEWS

June Employment Report: Sector Adds Jobs for 4th Consecutive Month

Employment in America's energy technology and services sector increased by an estimated 8,002 jobs in June, a fourth consecutive month of growth, according to preliminary data from the Bureau of Labor Statistics (BLS) and analysis by the Energy Workforce & Technology Council.

The 1.3% growth comes after the sector added nearly 24,000 positions over the past three months after hitting a pandemic low of 591,413 jobs in February, according to BLS data. Gains over the past four months bring the sector to a net increase of an estimated 9,043 jobs in 2021.

The monthly Energy Technology & Services Employment Report, compiled and published by the Council, estimates a peak of nearly 102,000 pandemic-related job losses. Since then, the sector has restored approximately 18,600 positions, bringing total pandemic employment cuts to 83,000 jobs and more than $9.4 billion in annualized lost wages.

Using BLS data, the Council, in consultation with researchers from the Hobby School of Public Affairs at the University of Houston, found that reductions were heaviest in April 2020, when the sector shed 57,294 jobs — the largest one-month total since at least 2013.

Sector employment has grown slowly in 2021 as companies have focused on reducing debt, repaying investors and investing in research and development instead of boosting production. Employment in the sector is down 11.8% since the onset of the pandemic in March 2020.

Below are the top states for employment in the energy technology and services sector, and estimated job gains in June 2021 compared to the same month in 2020, according to BLS data:

1. **Texas** — 303,100, +4,400 jobs
2. **Louisiana** — 52,100, +745
3. **Oklahoma** — 47,400, +679
4. **Colorado** — 25,300, +362
5. **New Mexico** — 23,300, +334
6. **California** — 22,800, +327
7. **Pennsylvania** — 22,600, +323
8. **North Dakota** — 19,400, +278
9. **Wyoming** — 14,500, +207
10. **Ohio** — 10,300, +148
11. **Alaska** — 9,700, +138
12. **West Virginia** — 9,500, +137

Energy technology and services sector employment is estimated by analyzing data published by the U.S. Bureau of Labor Statistics and covers the economic activities of energy technology and services companies, which include oil and gas extraction, construction and manufacturing. Total employment is estimated using the Quarterly Census of Employment and Wages, published by BLS, and jobs data reported by BLS monthly.

Note: BLS data is preliminary for the two most recent months and is subject to revision. The Council incorporates monthly totals according to BLS corrections, and updates the statistical model quarterly.

For additional information or questions about the report, contact lead researcher and Council Director of Communications and Research **Kevin Broom**.

https://biv.com/article/2021/07/trans-mountain-pipeline-hits-major-milestone

Trans Mountain pipeline hits a major milestone

Start of tunnel through Burnaby Mountain brings expansion to 30% completion

By Nelson Bennett | July 14, 2021

Twinning a 1,150-kilometre long pipeline is no mean feat of engineering, especially considering that the last 2.6 kilometres pipe has to be threaded through a mountain.

The $12.6 billion Trans Mountain pipeline twinning project is one of four major energy-related construction projects underway in B.C. It will add a second pipeline to the existing one, which runs from Edmonton to Burnaby, increasing its capacity to 890,000 barrels per day from 300,000.

A total of 13,000 people have been hired since construction started. At the end of May, the project alone accounted for 9,000 workers in Alberta and B.C. About 1,900 are concentrated in the Lower Mainland, with much of that manpower focused on expansions of the Burnaby tank farm and Westridge Marine Terminal.

“The terminals are really some of the big meat of the work,” said Trans Mountain Corp. manager of communications Ali Hounsell in a recent progress update. “Overall, we’re at just over 30% complete on the project, and that’s as of mid-June. We have 182 kilometres of pipe in the ground. The completion rate really varies spread by spread.”

The pipeline twinning project is broken into nine sections or “spreads.” Spread 1 out of Edmonton is 94% complete, whereas work on the Fraser Valley – Spread 6 – hasn’t even started yet, as the company is still waiting for the Canadian Energy Regulator to issue permits from detailed route hearings.

Much of the work is being done by Canadian contractors, although there are a few points along the pipeline’s route that pose some engineering, geotechnical and construction challenges that require expertise not found in Canada.

Burying a pipeline in the steep mountainous terrain between Hope and the Coquihalla Summit, for example, requires international technical expertise and specialized equipment. For that section, Trans Mountain has contracted Kiewit and an Italian company, Bonatti.

“We’re running grades of 30 degrees up there,” said Dean Palin, head project director for the TMX project. “So we brought in Kiewit Bonatti Group to help us get through the steep slopes on that piece of it.”

Trans Mountain also brought in specialized marine barge-crane operators from the U.S. to work on the foreshore of Westridge Marine terminal.

One of the bigger engineering challenges is boring a 2.6-kilometre tunnel through Burnaby Mountain. A major milestone in the project’s construction was achieved May 26, when tunnel boring officially began. The tunnel is needed to connect the Burnaby tank farm and Westridge Marine Terminal with distribution lines.

The Burnaby tank farm is being expanded with 14 additional storage tanks. The Westridge Marine terminal, where oil is loaded onto tankers for export, involves the construction of three new berths. This requires the installation of 162 piles, and all of this has to be done in the water around the terminal without interfering with ongoing operations.

The marine terminal and tank farm are more than two kilometres apart and are connected by distribution pipes that were originally put underground in the 1950s. Since then, the City of Burnaby has built up around that area. So rather than tear up city streets to install new distribution pipes to connect the Burnaby tank farm and Westridge Marine Terminal, planners decided to bore the long tunnel through Burnaby Mountain.

The tunnel boring took a year of preparatory work and six years of planning, design and regulatory approvals. The prep work included building entrance and exit portals at either end, which required the construction of retaining walls at the Burnaby tank farm and Westridge Marine Terminal.

This involved 106 secant piles being sunk 18 metres deep into the ground at the marine terminal end. About 300,000 cubic metres of soil then had to be excavated in front of these piles to reveal the new retaining walls, and then a platform was built for the tunnel boring machine. Another small retaining wall was built at the Burnaby Tank farm end.

The boring began with cutting a 4.4-metre entrance into the new retaining wall near Westridge Marine Terminal.

Chewing through a mountain requires specialized machinery. A custom-built tunnel boring machine was built by Herrenknecht AG in Germany at a cost of about $10 million. The machine is 122 metres long – the length of a soccer field – and is operated by a crew of 12, who work inside the machine.

The machine operates seven days a week, 24 hours a day. It will take about 290 days to complete the tunnel. As of the end of June, only about 25 metres of the tunnel had been excavated.

“Right now, we’re not moving very fast, because as we slowly start to wind this machine up, we’ve got commissioning that’s ongoing, making sure everything’s right before we get too far into the tunnel,” Palin said.

The expansion project has suffered a number of delays and stop-work orders. Some of the delays were due to the pandemic, but there was also a three-week halt-work order issued by Trans Mountain in December, after a number of workplace injuries, including one fatality.

“It’s such a huge project, and we’ve had some challenges,” Hounsell said. “We had a clearing stop-work order a little while ago. COVID obviously has been a challenge in many different ways, but in some other ways we catch up. Overall, we are still projecting for completion at the end of 2022.” •

Posted as of July 15, 2021

https://www.transmountain.com/project-overview

Expansion Project

The original Trans Mountain Pipeline was built in 1953 and continues to operate safely today. The Expansion is essentially a twinning of this existing 1,150-kilometre pipeline between Strathcona County (near Edmonton), Alberta and Burnaby, BC. It will create a pipeline system with the nominal capacity of the system going from approximately 300,000 barrels per day to 890,000 barrels per day.

On June 18, 2019 the Government of Canada approved the Trans Mountain Expansion Project. The Project is subject to 156 conditions enforced by the Canada Energy Regulator.

Here are some quick facts about the expansion:

- It will be approximately 980 km of new pipeline
- 73 per cent of the route will use the existing right-of-way, 16 per cent will follow other linear infrastructure such as telecommunications, Hydro or highways and 11 per cent will be new right-of-way
- It will include 193 km of reactivated pipeline
- 12 new pump stations will be built
- 19 new tanks will be added to the existing storage terminals in Burnaby (14), Sumas (1) and Edmonton (4)
- Three new berths will be built at Westridge Marine Terminal in Burnaby. Once the new berths are completed and in service, the number of tankers loaded at the Westridge Marine Terminal could increase to approximately 34 per month.
- The existing pipeline will carry refined products, synthetic crude oils, and light crude oils with the capability for heavy crude oils
- The new pipeline will carry heavier oils with the capability for transporting light crude oils
- Engagement with communities, landowners, stakeholders and Indigenous communities has been ongoing since 2012 and will continue through to operation
- Environmental protection plans have been developed along the entire route. Volume 5 and Volume 6 of the Facilities Application cover the environmental assessment and protection planning. We will continue to conduct field studies along the route as required.
- It's expected to cost approximately $12.6* billion.
- Expected in-service date is December, 2022.
- It will create benefits including new short- and long-term jobs, job-related training opportunities and increases in taxes collected by all three levels of government
- To date, Trans Mountain and our contractors have hired approximately 13,185 people to work on the Expansion Project.
- The combined impact on government revenue for construction and the first 20 years of expanded operations is $46.7 billion; revenues that can be used for public services such as health care and education – British Columbia receives $5.7 billion, Alberta receives $19.4 billion and the rest of Canada receives $21.6 billion.*

**Actual project costs may change. Numbers are based on Conference Board of Canada studies in 2014 and 2015; and Canadian Chamber of Commerce report in 2013*

Why expand?

The Trans Mountain Expansion Project will help make sure Canada gets full value for its oil. Everyone will benefit. Workers will benefit during the $12.6* billion construction project. Oil producers will earn more revenue for their product. Government will collect more tax revenue from oil. These revenues contribute to services that benefit all Canadians.

Currently, nearly all the oil produced in Western Canada goes to one market, the United States Midwest. However, there's a limit to how much oil this market needs. For much of the last decade, Canada has been selling into the United States at a discount to the world price for similar oil products.

The simple truth is that Canada's oil will fetch a better price if we give ourselves the option of shipping more of it via Trans Mountain's Pacific tidewater terminal in Burrard Inlet. Canada will earn more on every barrel of oil that's piped west compared to those sold to our existing customers in the United States Midwest market, a differential that exists regardless of the price of oil. The Project will allow Canadian oil to be delivered to international markets and, as a result, Canada will earn approximately $3.7 billion more per year.

Independent estimates conclude oil producer revenues will increase by $73.5 billion over 20 years of operations and Canada will earn $46.7 billion in additional taxes and royalties to federal and provincial governments.

With oil sands production expanding in Alberta in the years ahead, new markets and new opportunities are emerging. As countries in Asia Pacific begin to develop the same quality of life we enjoy here in Canada, they need to secure sources of energy. Canada is a natural trading partner for these countries, and with an expanded Trans Mountain Pipeline system, we will be in a position to provide for their growing needs for years to come.

Who's involved?

When oil producers told us they could reach new markets by expanding the capacity of North America's only pipeline with access to the West Coast, Trans Mountain proposed the Expansion Project.

These oil producers have made significant 15- and 20-year commitments that add up to roughly 80 per cent of the capacity in the expanded Trans Mountain Pipeline:

- Athabasca Oil Corporation
- BP Canada Energy Trading Company
- Canadian Natural Resources Limited
- Cenovus Energy Inc.
- Imperial Oil Limited
- MEG Energy Corp.
- PetroChina Canada Limited
- Suncor Energy Marketing Inc.
- Teck Canadian Energy Sales Ltd.
- Marathon Petroleum Canada Trading & Supply ULC
- Total E&P Canada Ltd.

Pipeline Alternatives

Pipelines are proven to be the safest and most efficient method to move petroleum products over great distances on land. Petroleum products can also be shipped by tanker trucks or railcars.

Every day, member companies of the Canadian Energy Pipeline Association (CEPA) move enough crude oil and petroleum products through pipelines to fill 15,000 tanker truckloads and 4,200 railcars. The existing Trans Mountain pipeline system moves the equivalent of about 1,400 tanker truckloads or 441 tanker railcars daily. Expanding the Trans Mountain pipeline results in safer, more efficient and more economic shipment of oil between Alberta and BC.

Previous Expansion

This is not the first expansion of the Trans Mountain line. In fact, since operation began in 1953, the capacity of the pipeline system has been increased numerous times, with the initial expansion in 1957. The most recent expansion project took place between 2006 and 2008 with the construction of 13 new pump stations and modifications to existing stations. Also during this time, the Anchor Loop project added 160 kilometres of new pipe through Jasper National Park and Mount Robson Provincial Park between Hinton, Alberta and Hargreaves, BC.

**Actual project costs may change. Numbers are based on Conference Board of Canada studies in 2014 and 2015; and Canadian Chamber of Commerce report in 2013* https://naalakkersuisut.gl/en/Naalakkersuisut/News/2021/07/1507_oliestop

Greenland halts new oil exploration

15.07.2021

The Greenlandic underground

The Greenlandic underground is rich in both oil resources and minerals, and the history of exploration and exploitation activities goes back many years and has a global reach.

The Greenlandic government, Naalakkersuisut, remains committed to developing the country's vast mineral potential, where this does not involve the extraction of uranium. Therefore, a draft-bill has just been sent out for consultation, which bans preliminary investigation, exploration and extraction of uranium in Greenland.

The Greenlandic population has based its livelihood on the country's natural resources for centuries, and the ban on uranium mining is rooted in a profound belief that business activities must take nature and the environment into account.

It is the same concerns that form the backdrop for the Greenlandic government's decision to introduce a stop to new oil and gas exploration.

An end to oil exploration

Greenlandic underground contains large unexplored deposits of oil. A recent study from The Geological Survey of Denmark and Greenland (GEUS) estimates that there are DKK 18 billion de-risked barrels of oil on the west coast of Greenland. Large deposits are also expected to hide below the seabed on the east coast of Greenland.

However, the Greenlandic government believes that the price of oil extraction is too high. This is based upon economic calculations, but considerations of the impact on climate and the environment also play a central role in the decision.

Against this background, Naalakkersuisut has decided to cease issuing new licenses for oil and gas exploration in Greenland. This step has been taken for the sake of our nature, for the sake of our fisheries, for the sake of our tourism industry, and to focus our business on sustainable potentials.

The Minister for Housing, Infrastructure, Mineral Resources and Gender Equality, Naaja H. Nathanielsen states:
"As a society, we must dare to stop and ask ourselves why we want to exploit a resource. Is the decision based upon updated insight and the belief that it is the right thing to do? Or are we just continuing business as usual? It is the position of the Greenlandic government that our country is better off focusing on sustainable development, such as the potential for renewable energy."

The Minister for Fisheries and Hunting, Aqqaluaq B. Egede says:
"The decision emphasizes that Greenland manages its natural resources sustainably. It is a strong signal to be able to announce that our fish and catch comes from a country that puts sustainable management of our natural resources high on the agenda. By doing so we can continue to supply the world's consumers with premium raw materials."

The Minister for Agriculture, Self-sufficiency, Energy and Environment, Kalistat Lund states:
"Naalakkersuisut takes climate change seriously. We can see the consequences in our country every day, and we are ready to contribute to global solutions to counter climate change. Naalakkersuisut is working to attract new investments for the large hydropower potential that we cannot exploit ourselves. The decision to stop new exploration for oil will contribute to place Greenland as the country where sustainable investments are taken seriously."

The Minister for Business, Trade, Foreign Affairs and Climate, Pele Broberg says:
"International investments in the energy sector in recent years are moving away from oil and gas and into renewable

energy. It is therefore natural that we emphasise business on the opportunities of the future and not on the solutions of the past. The decision to halt oil exploration is also the story of a population that puts the environment first. It is a story I look forward to sharing with the tourism sector and include when I represent Greenland internationally."

For more information contact: Ministry of Mineral Resources; e-mail: asn@nanoq.gl

Oil Market Highlights

Crude Oil Price Movements

Crude oil spot prices rose firmly in June, extending previous monthly gains, driven by a rally in futures markets, as well as a strengthening global physical crude market, amid higher crude demand from refiners. The OPEC Reference Basket (ORB) increased for the second-consecutive month in June, reaching its highest monthly average since October 2018. The ORB value rose $4.98 m-o-m, or 7.4%, to settle at an average of $71.89/b. Year-to-date (y-t-d), the ORB averaged $63.85/b, representing a gain of $24.64, or 62.9%, compared to the same month last year. In June, investors turned increasingly optimistic about the outlook for the oil demand recovery amid expectations for a tighter global oil market in 2H21. The ICE Brent front month rose $5.10 m-o-m in June, or 7.5%, to average $73.41/b, and NYMEX WTI increased $6.20, or 9.5%, m-o-m to average $71.35/b. Consequently, the ICE Brent and NYMEX WTI spread narrowed by $1.10 m-o-m to average $2.06/b in June, its lowest level since October 2020. The backwardation structure of all three major oil benchmarks strengthened in June on a tightening outlook for oil supply and demand fundamentals in the coming months. Hedge funds and other money managers boosted bullish positions related to crude in June, particularly in WTI, as speculators focus on expectations for rising oil prices.

World Economy

The global economic growth forecast for 2021 remains unchanged at 5.5%. In an initial assessment, global economic growth for 2022 is forecast at 4.1%. However, future global growth continues to be impacted by uncertainties, including the spread of COVID-19 variants and the pace of the global vaccine rollout. In addition, sovereign debt levels in many regions, together with inflationary pressures and central bank responses, remain key factors that require close monitoring. Nevertheless, upside potential could materialize as ongoing containment COVID-19 measures in combination with additional fiscal and monetary stimulus could turn out to be more effective than envisaged, leading to further gains in consumption and investments. US economic growth in 2021 remains at 6.4%, followed by growth of 3.6% in 2022. The Euro-zone economic growth in 2021 remains at 4.1%, followed by growth of 3.0% in 2022. Similarly, Japan's economic growth forecast remains at 2.8% for 2021, followed by growth of 2.0% in 2022. After an unchanged growth forecast of 8.5% in 2021, China's economic growth forecast for 2022 stands at 6.3%. India's 2021 growth forecast remains at 9.5%, followed by growth of 6.8% in 2022. Brazil's growth forecast for 2021 was revised up to 3.2%, followed by growth of 2.5% in 2022. Russia's forecast for 2021 remains at 3.0%, followed by growth of 2.3% in 2022.

World Oil Demand

World oil demand growth in 2021 is forecast at 6.0 mb/d, unchanged from last month's assessment, although there have been some regional revisions. Total oil demand is projected to average 96.6 mb/d. The 1Q21 was revised lower, amid slower than anticipated demand in the main OECD consuming countries. This was counterbalanced by better-than-expected data from OECD Americas in 2Q21, which is now projected to last through the 3Q21. Solid expectations exist for global economic growth in 2022. These include improved containment of COVID-19, particularly in emerging and developing countries, which are forecast to spur oil demand to reach pre-pandemic levels in 2022. World oil demand is anticipated to rise by 3.3 mb/d y-o-y in 2022, while total world oil demand is projected to average 99.86 mb/d, with the 100 mb/d mark exceeded in 2H22. OECD oil demand is anticipated to increase by 1.5 mb/d, as OECD Americas is expected to rise firmly with US oil demand only marginally below 2019 levels, mainly due to lagging transportation fuel demand. Non-OECD oil demand is projected to show an increase of 1.8 mb/d, with gains in China and India exceeding pre-pandemic levels, supported by a respectable recovery in transportation fuels and firm industrial fuel demand, including petrochemical feedstock.

World Oil Supply

Non-OPEC liquids supply in 2021 is revised down by 0.03 mb/d, despite upward revisions to the US and Canada. Growth is now at 0.81 mb/d for an average of 63.8 mb/d. The preliminary US liquids production recovery in 2Q21 indicates an increase of 1 mb/d, q-o-q. The main drivers for 2021 supply growth are expected to be Canada, China, Norway, Brazil and Guyana, with the US now expected to see y-o-y growth of 0.06 mb/d. The initial forecast for 2022 sees non-OPEC liquids supply growing by 2.1 mb/d, with a 1.1 mb/d expansion in in the OECD, 0.8 mb/d growth in the non-OECD and a 0.1 mb/d recovery in processing gains. At the same time, uncertainty remains high regarding financial and operational aspects of US production. OPEC NGLs are forecast to grow by 0.1 mb/d y-o-y in 2021 and 2022 to average 5.2 mb/d and 5.3 mb/d, respectively. OPEC crude oil production in June increased m-o-m by 0.59 mb/d, to average 26.03 mb/d, according to available secondary sources.

Product Markets and Refining Operations

Refinery margins in all main trading hubs declined in June as refineries ramped up processing rates following peak spring refinery maintenance season, which led to stronger product availability. This led to a longer overall product balance, as product output outpaced fuel consumption recovery, weighing on product crack spreads. The ongoing vaccination rollout and optimism following the relaxation of lockdown measures in many countries, leading to expectations of higher fuel consumption levels going forward, contributed to the rise in refinery runs, which are expected to remain strong in the near term.

Tanker Market

Dirty tanker rates remained at depressed levels in June as ample tonnage availability and limited tanker demand continued to weigh on the market. The search for better rates have even encouraged the use of new built VLCCs to carry clean products, eroding clean tanker rates. New deliveries, minimal scrapping and weak tanker demand point to a continued sluggish tanker market, possibly into next year.

Crude and Refined Products Trade

The US provided key seasonal support for global trade flows in June, according to preliminary data. US crude imports rose 0.7 mb/d m-o-m, or more than 11%, to average 6.7 mb/d in June, the highest since December 2019. US crude exports also rose sharply m-o-m in June, jumping 0.8 mb/d or almost 30%, to average 3.6 mb/d, the second-highest on record. China’s crude oil imports averaged 9.7 mb/d in May, representing a further decline of 0.2 mb/d or 2% m-o-m and a cumulative decline of 2.1 mb/d or 18% over the last two months. Preliminary figures for June show the country’s crude imports ticking up, but remaining below 10 mb/d. India’s crude imports fell to a seven-month low in May, as the peak of the second COVID-19 wave arrived in the middle of that the month. With reduced COVID-19 infections at the end of June, refiners in India have begun began to slowly lift run rates which could strengthen crude inflows in July. Meanwhile, Japan’s crude imports fell back in May from the strong levels seen the month before, averaging 2.4 mb/d, as renewed lockdown measures undermined expectations for product demand. The start of the 2021 Tokyo Olympics in July should provide some boost to crude and product imports, although uncertainty regarding COVID-19 measures are clouding product needs.

Commercial Stock Movements

Preliminary May data sees total OECD commercial oil stocks up by 8.3 mb m-o-m. At 2,934 mb, inventories were 276.9 mb lower than the same month last year; 86.6 mb lower than the latest five-year average; and 21.7 mb below the 2015-2019 average. Within components, crude and product stocks were up by 1.1 mb and 7.2 mb, respectively. At 1,466 mb, OECD crude stocks stood 60.8 mb below the latest five-year average and 32.5 mb below the 2015-2019 average. At 1,468 mb, OECD product stocks were 25.9 mb below the latest five-year average, but 10.8 mb above the 2015-2019 average. In terms of days of forward cover, OECD commercial stocks fell 0.8 days m-o-m in May to stand at 64.2 days. This is 13.4 days below the May 2020 level, 0.8 days below the latest five-year average, but 2.4 days above the 2015-2019 average.

Balance of Supply and Demand

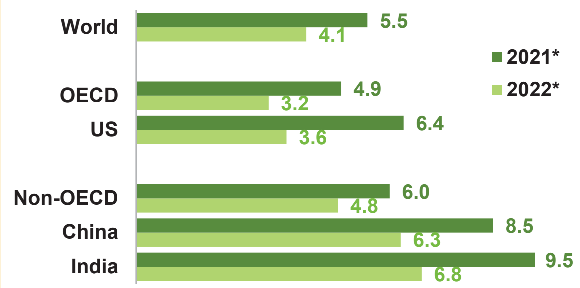
Demand for OPEC crude in 2021 remains unchanged from the previous report at 27.7 mb/d, around 5.0 mb/d higher than in 2020. Based on the initial forecasts for world oil demand and non-OPEC supply in 2022, demand for OPEC crude is forecast at 28.7 mb/d, some 1.1 mb/d higher than the 2021 level.

Feature Article

The outlook for the oil market in 2022

Following a strong rebound in 2021, global economic growth in 2022 is forecast to grow by 4.1%, y-o-y (***Graph 1***).

Graph 1: GDP growth forecast, y-o-y changes, %



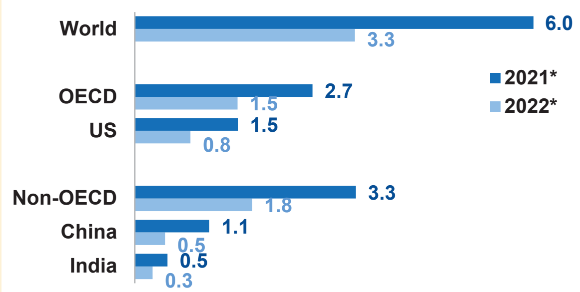
*Note: * 2021-2022 = Forecast. Source: OPEC.*

This forecast assumes continued progress in the containment of the COVID-19 pandemic. Moreover, the ongoing broad-based stimulus measures and high saving rates in advanced economies are forecast to lead to a release of pent-up demand in 2H21, which will carry over into 2022. Consumption is forecast to improve, particularly in the contact-intensive sectors. However, a strong recovery could lead to a quick rise in inflation and consequently rising interest rates. Very high sovereign debt levels could thus become a considerable burden for the fiscal health of many economies.

The positive developments in the containment of the pandemic as well as the solid expectations for global economic growth are assumed to spur consumption for oil in 2022, with world oil demand forecast to grow by 3.3 mb/d y-o-y, to average 99.9 mb/d. World oil demand in 2H22 is expected to exceed 100 mb/d.

Within regions, OECD oil demand is forecast to rise by 1.5 mb/d. Of this, OECD Americas is expected to rise firmly, with US oil demand marginally below 2019 levels, mainly due to lagging transportation fuel demand. OECD Europe and Asia Pacific will grow, but remain below 2019 levels. Non-OECD oil demand is projected to show an increase of 1.8 mb/d, rising the most in China and India to exceed pre-pandemic levels, supported by a recovery in transportation fuels and firm industrial fuels demand, including petrochemical feedstocks.

Graph 2: World oil demand growth forecast, y-o-y changes, mb/d

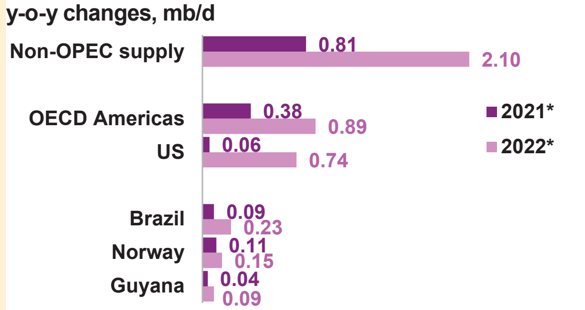


*Note: * 2021-2022 = Forecast. Source: OPEC.*

In terms of fuels, gasoline and diesel are expected to lead oil demand growth in 2022. The gradual return to normalcy is expected to support mobility in major consuming countries, such as the US, China and India. Both on-road diesel, including trucking, as well as increasing industrial, construction and agricultural activities in OECD America, Europe and China will support diesel demand. Light distillates will be supported by capacity additions – NGL plants in the US, Propane Dehydrogenation (PDH) plants in China, and steady petrochemical margins. Jet fuel will continue to recover, as domestic and international air travel pick up, but business travel is expected to lag. Uncertainties remain, including COVID-19-related challenges and their impact on transportation fuels; the above-mentioned economic developments; extreme weather; technological advances, including digitalization; penetration of electric vehicles; and energy policy changes.

Non-OPEC oil supply is forecast to grow by 2.1 mb/d y-o-y in 2022, on stronger demand and higher oil price levels. Upstream investment in non-OPEC countries is expected at around $348 billion, a minor increase from 2020-2021 levels, but still only half of the $737 bn seen in 2013. The expected cumulative output from new projects has been decreasing, from 109 mb/d in 2013 to only 19 mb/d in 2021. US production is forecast to grow by 0.7 mb/d. Oil production growth in North America, forecast at 0.9 mb/d, will come from the Permian Basin, Gulf of Mexico and oil sands in Canada. Oil production in Brazil, Norway, Guyana, China, India and the UK is expected to increase through the ramping up of existing projects and new field start-ups. Moreover, OPEC NGLs are forecast to grow by 0.1 mb/d y-o-y.

Graph 3: Non-OPEC supply growth forecast, y-o-y changes, mb/d



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

Looking ahead to 2022, risks and uncertainties loom large and require careful monitoring to ensure the recovery from the COVID-19 pandemic. OPEC and the non-OPEC countries participating in the Declaration of Cooperation (DoC) will continue to closely evaluate the various factors that could impact the ongoing developments on a monthly basis, thereby being able to act swiftly in a very timely manner to safeguard the delicate recovery of the market balance.

World Oil Demand

For 2021, world oil demand is foreseen to rise by 6.0 mb/d, unchanged from last month's estimate and despite some regional revisions. Total oil demand is projected to average 96.6 mb/d. 1Q21 was revised down amid slower-than-anticipated demand in the main OECD consuming countries. This was counterbalanced by better-than-expected data from OECD Americas in 2Q21, which is now projected to continue through 3Q21.

In the OECD region, oil demand is anticipated to rise by 2.7 mb/d to reach 44.7 mb/d of total demand. This is nearly 3.0 mb/d lower than total demand in 2019, mainly due to a limited recovery in transportation fuel, especially jet fuel. OECD Americas demand is anticipated to rise the most in 2021, led by the US on the back of recovering gasoline and diesel demand. Light distillates are also projected to support demand growth this year.

In the non-OECD region, oil demand is anticipated to rise by 3.3 mb/d to reach 51.9 mb/d of total demand in 2021. That is nearly 0.4 mb/d lower than 2019 total demand, despite expectations of fully recovering demand in China and India. A steady increase in industrial and transportation fuel demand supported by recovering economic activity is projected to boost demand in 2021.

In 2022, healthy expectations for global economic growth in addition to improved containment of COVID-19 through the acceleration of vaccination programmes, effective treatment and natural immunization, particularly in emerging and developing countries, along with frequent testing procedures, are assumed to spur consumption of oil next year to comparable pre-pandemic levels. World oil demand is anticipated to rise by 3.3 mb/d y-o-y, while total world oil demand is projected to reach 99.9 mb/d with 2H22 exceeding 100 mb/d.

In the OECD, oil demand is anticipated to rise by 1.5 mb/d, as OECD Americas is expected to climb firmly, with US oil demand marginally below 2019 levels mainly due to lagging transportation fuel demand. OECD Europe and Asia Pacific will grow but remain lingering below 2019 consumption levels.

In the non-OECD, oil demand is projected to show an increase of 1.8 mb/d with demand growth rising the most in China and India to exceed pre-pandemic levels, supported by a respectable recovery in transportation fuels and firm industrial fuel demand, including petrochemical feedstock. Other regions such as Other Asia, Latin America and the Middle East are also expected to see decent gains, supported by a positive economic outlook.

In terms of fuels, gasoline and diesel are assumed to lead oil demand growth next year. A gradual return to pre-COVID-19 normality is expected to continue into 2022, which in turn will further support mobility in major consuming countries such as the US, China and India. Diesel gains will stem from both on-road diesel, including trucking, as well as increasing momentum in industrial, construction and agricultural activities in OECD America, Europe and China. Light distillates will be supported by new capacity additions; NGL plants in the US, propane dehydrogenation (PDH) plants in China and steady petrochemical margins are assumed to additionally encourage demand for light-end products. Jet fuel will continue its recovery as domestic and international air travel pickup their pace, but slower demand for business travel will pressure this product category, forcing it to return to 2019 levels.

The forecast remains subject to uncertainties, most profoundly COVID-19-related challenges and their impact on transportation fuels, trade tension issues, developments on the economic front, unusual weather conditions, the impact of technological advancements including digitalization, penetration of electric vehicles and energy policy changes are principal factors that may influence the short-term forecast for oil demand.

World oil demand in 2021 and 2022

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

World oil demand	2020	1Q21	2Q21	3Q21	4Q21	2021	Change 2021/20 Growth	%
Americas	22.56	23.09	24.73	24.84	24.75	24.36	1.80	7.99
of which US	*18.44*	*18.99*	*20.11*	*20.34*	*20.45*	*19.98*	*1.54*	*8.33*
Europe	12.43	11.88	12.73	13.61	13.71	12.99	0.56	4.49
Asia Pacific	7.07	7.61	7.17	7.16	7.51	7.36	0.29	4.16
Total OECD	**42.06**	**42.58**	**44.63**	**45.61**	**45.97**	**44.72**	**2.65**	**6.31**
China	13.19	12.95	14.27	14.93	15.05	14.30	1.11	8.43
India	4.51	4.94	4.52	4.91	5.61	5.00	0.49	10.82
Other Asia	8.13	8.36	8.93	8.54	8.59	8.61	0.47	5.83
Latin America	6.01	6.15	6.16	6.46	6.40	6.29	0.28	4.68
Middle East	7.55	7.95	7.67	8.24	7.97	7.96	0.42	5.51
Africa	4.08	4.39	3.96	4.16	4.48	4.25	0.16	4.03
Russia	3.37	3.57	3.37	3.57	3.74	3.56	0.19	5.77
Other Eurasia	1.07	1.18	1.19	1.14	1.28	1.20	0.12	11.43
Other Europe	0.65	0.73	0.62	0.68	0.74	0.69	0.05	6.97
Total Non-OECD	**48.56**	**50.23**	**50.69**	**52.62**	**53.85**	**51.86**	**3.30**	**6.79**
Total World	**90.62**	**92.80**	**95.32**	**98.24**	**99.82**	**96.58**	**5.95**	**6.57**
Previous Estimate	90.62	92.93	95.26	98.18	99.82	96.58	5.95	6.57
Revision	0.00	-0.13	0.06	0.06	0.00	0.00	0.00	0.00

*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	24.36	24.33	25.64	25.72	25.55	25.32	0.95	3.92
of which US	*19.98*	*20.05*	*20.89*	*21.11*	*21.17*	*20.81*	*0.83*	*4.16*
Europe	12.99	12.38	13.15	14.01	14.04	13.40	0.41	3.17
Asia Pacific	7.36	7.85	7.36	7.29	7.62	7.53	0.17	2.27
Total OECD	**44.72**	**44.55**	**46.14**	**47.02**	**47.21**	**46.25**	**1.53**	**3.43**
China	14.30	13.50	14.75	15.32	15.44	14.76	0.45	3.16
India	5.00	5.28	4.75	5.14	5.88	5.26	0.27	5.32
Other Asia	8.61	8.78	9.24	8.82	8.86	8.93	0.32	3.72
Latin America	6.29	6.39	6.34	6.61	6.56	6.48	0.18	2.89
Middle East	7.96	8.29	7.91	8.49	8.20	8.23	0.26	3.32
Africa	4.25	4.57	4.09	4.28	4.61	4.39	0.14	3.29
Russia	3.56	3.67	3.42	3.62	3.79	3.63	0.07	1.83
Other Eurasia	1.20	1.25	1.23	1.17	1.32	1.24	0.05	3.76
Other Europe	0.69	0.75	0.63	0.69	0.76	0.71	0.02	2.38
Total Non-OECD	**51.86**	**52.48**	**52.37**	**54.15**	**55.41**	**53.61**	**1.75**	**3.38**
Total World	**96.58**	**97.03**	**98.52**	**101.17**	**102.62**	**99.86**	**3.28**	**3.40**

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

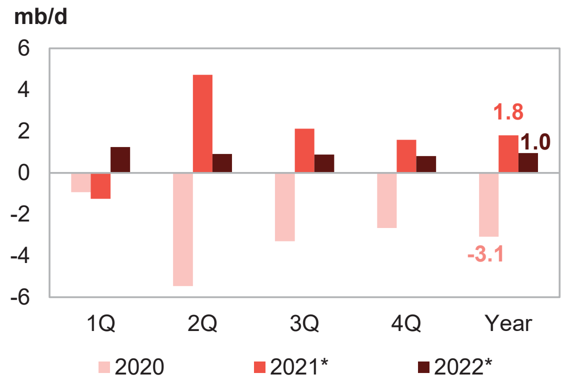
OECD

OECD Americas

Update on the latest developments

Oil demand in **OECD Americas** increased by 6.0 mb/d y-o-y in **April**, following an increase of 0.6 mb/d y-o-y in March. More than 60% of this increase is attributed to recovering transportation fuels, particularly gasoline and jet fuel requirements. Gasoline grew by a massive 3.3 mb/d y-o-y with rebounding miles travelled weighing in. A historical drop in April 2020 also contributed to this gain. Demand for transportation fuels, as well as total petroleum product demand, remained lingering below April 2019 as gasoline and jet fuel recorded a 1.6 mb/d drop compared with April 2019, while total petroleum product consumption was lower by 0.9 mb/d compared with April 2019. All countries in the region posted solid gains as demand rebounded most in the US, followed by Canada, Mexico and Chile.

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



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

The latest available **US** monthly demand data for **April** imply sharply increasing US oil demand by approximately 4.8 mb/d y-o-y, making up 85% of losses incurred during the historical drop of April 2020. Demand was lower than in April 2019 by almost 0.9 mb/d. Gasoline and jet kerosene requirements increased the most, with gasoline gaining 2.9 mb/d y-o-y, while jet/kerosene increased by 0.6 mb/d y-o-y in April 2021. Both fuels fell sharply during the April 2020 COVID-19 pandemic, by 3.6 mb/d and 1.1 mb/d y-o-y, respectively. According to the Federal Highway Administration, vehicle miles of travel in the US shot up by 54.6% y-o-y in April this year after rising by 18.8% y-o-y in March. In April 2020, the indicator plunged by more than 40% y-o-y, to the lowest y-o-y- decline ever recorded. Additionally, light vehicle retail sales, as reported by Autodata and Haver Analytics, were at 18.7 million units according to seasonally adjusted annual rates (SAAR), compared with 18.1 million units in March. A quick recap of historical figures for the same index show total sales of 8.7 million units in April 2020 and 16.6 million units in April 2019. Industrial production, a gauge for industrial fuel demand, was also higher by 17.6% y-o-y in April after increasing by 1.5% y-o-y in March. The index dropped similarly in April 2019 by approximately 17.7% y-o-y, according to Federal Reserve Board data. Diesel demand was higher by 0.5 mb/d y-o-y in April 2021 following an increase of 0.1 mb/d in March. Diesel consumption was at par with April 2019 levels.

Preliminary data for May based on weekly input indicate the continuation of a recovery in transportation fuel performance, with both gasoline and jet kerosene increasing by more than 2.7 mb/d y-o-y collectively. Diesel is foreseen to increase by 0.5 mb/d y-o-y in May 2021.

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

			Change Apr 21/Apr 20	
By product	**Apr 20**	**Apr 21**	**Growth**	**%**
LPG	2.83	2.89	0.06	2.1
Naphtha	0.15	0.21	0.06	39.2
Gasoline	5.85	8.79	2.94	50.2
Jet/kerosene	0.69	1.29	0.59	85.7
Diesel	3.51	3.99	0.48	13.8
Fuel oil	0.13	0.14	0.02	14.4
Other products	1.83	2.44	0.62	33.8
Total	**14.98**	**19.75**	**4.77**	**31.8**

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

Near-term expectations

Going forward, the vaccination rollout has provided optimism regarding management of the COVID-19 pandemic, together with massive stimulus programmes, high household savings and improving unemployment rates. This supports a positive outlook for oil demand prospects until the end of the year. The outlook remains pressured by COVID-19 developments, including the emergence of new variants and possible government countermeasures. A rebound in transportation fuels, including gasoline, is associated with labour market developments and gasoline retail prices, which currently are assumed to be limited due to high household savings. Risks stemming from the structural impact of COVID-19 on consumer behaviour, especially in the aviation sector, as well as the speed of vaccination programmes, are to be monitored closely going forward. Nevertheless, the aviation sector is projected to remain below 2019 levels.

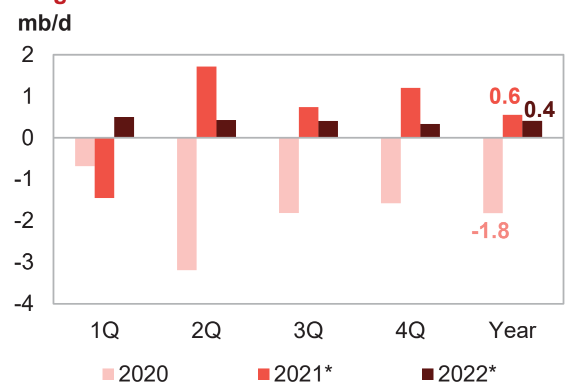
In **2022**, OECD Americas oil demand is projected to increase by around 1.0 mb/d y-o-y with the US leading the region, up by more than 0.8 mb/d y-o-y. Demand growth will be driven by healthy economic growth, supported by large stimulus packages. Additionally, a strong increase in household savings during the pandemic and improved unemployment data will lend support to oil demand next year. Gasoline is projected to continue recovering in 2022, supported by improved unemployment rates, higher miles driven y-o-y, and steady y-o-y increases in vehicle sales. However, gasoline demand is anticipated to lag in 2019, pressured by a number of factors such as penetration of alternative fuels vehicles, improved efficiency in combustion engines and the increased use of technology impacting mobility. Expansion in the petrochemical industry, coupled with healthy petrochemical margins, will provide additional support to light distillates in 2022. On the other hand, reduced business travel post-2021, a continuation in fuel substitution programmes, and fuel efficiency gains, particularly in the road transportation sector, are all factored into OECD America's 2022 oil demand outlook.

OECD Europe

Update on the latest developments

European oil demand recorded the first monthly y-o-y increase in **April**, for the first time since April 2019 and the third time since August 2018. Demand showed an increase of almost 1.9 mb/d y-o-y, following a decline of 0.4 mb/d in March. When contrasted with April 2019, oil demand remained drastically lower by 2.2 mb/d as impairment in jet fuel demand lagged April 2019 levels by nearly 1.0 mb/d. The y-o-y increase in April 2021 oil demand originated with diesel, primarily automotive diesel, and gasoline for road transportation, in addition to higher requirements for jet kerosene and fuel oil. Demand gains were marginally offset by declines in industrial diesel and the other product groups. Increases were the highest in France and Italy by 0.4 mb/d and 0.3 mb/d y-o-y, respectively.

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



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

Mobility inched higher in the region, moving from around 79% of pre-pandemic levels in March to 81% in April and continuing to edge higher in May and June as the main economies in the regions relaxed COVID-19 restriction measures amid falling infection cases. Mobility improved the most in the UK, Spain and Italy, while it stagnated in Germany and declined in France.

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

By product	Apr 20	Apr 21	Change Apr 21/Apr 20 Growth	%
LPG	0.38	0.43	0.05	13.1
Naphtha	0.53	0.60	0.07	13.6
Gasoline	0.65	0.97	0.32	49.3
Jet/kerosene	0.26	0.34	0.09	33.5
Diesel	2.58	2.98	0.40	15.5
Fuel oil	0.12	0.16	0.03	26.0
Other products	0.38	0.38	0.00	-1.0
Total	**4.90**	**5.86**	**0.96**	**19.5**

*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.

Certainly, the historical decline in consumption in April 2020 created a statistical gap in consumption data. Transportation fuel demand was steeply lower than in April 2019, as diesel and gasoline were 0.5 mb/d and 0.3 mb/d lower than April 2019 levels. One of the indicators of European oil demand, new passenger car registrations, increased in April by 222% y-o-y, after increasing by 91.7% in March. It's worth highlighting that the indicator recorded a decline of 78.8% y-o-y in April 2020 and 65.9% y-o-y in March 2020.

Near-term expectations

Going forward, the general expectations for the region's oil demand in May, June and 2H21 remain positive with some predominant downside risks, as a result of uncertainties in relation to unforeseen strong COVID-19 waves that could strain the medical system or/and possible disruption of vaccination programmes. On the one hand, projected improvements in the economy, particularly in the travel and tourism, hospitality and leisure sectors, government-led stimulus programmes, improved mobility – both road and air – and last year's low baseline call for a steady recovery in oil requirements throughout 2H21.

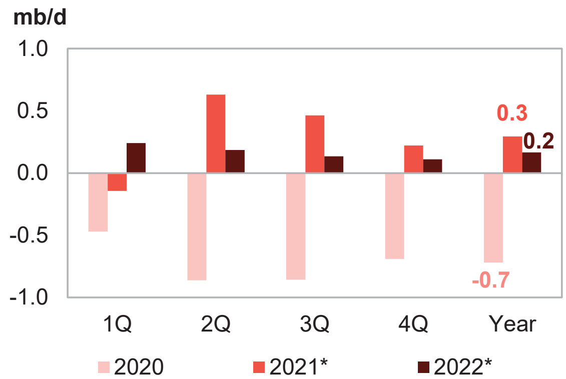
In **2022**, OECD Europe oil demand is anticipated to rise by around 0.4 mb/d. Estimated developments in the economy, along with better containment of COVID-19, are the main assumptions for OECD Europe oil demand growth in 2022. In terms of products, middle distillates – including automotive diesel, followed by gasoline – are anticipated to lead product consumption in 2022, supported by improvements in mobility amid better COVID-19 containment measures, along with positive developments in the industrial and construction sectors. Conversely, downward risks that might affect the 2022 oil demand outlook are mostly related to economic uncertainty, including high debt levels and budgetary constraints, in addition to fuel substitution and efficiencies in the road transportation sector. OECD Europe oil demand will continue to linger below 2019 levels, mainly due to a slower pace of recovery in the transportation sector leading to slowly growing jet fuel and on-road diesel requirements compared with pre-pandemic levels.

OECD Asia Pacific

Update on the latest developments

OECD Asia Pacific oil demand increased by 0.4 mb/d y-o-y in **April**, following an increase of more than 0.1 mb/d y-o-y in March. However, data showed significantly lower levels than in April 2019 by almost 1.0 mb/d, pressured by weak jet fuel, diesel and gasoline demand. Demand increased the most in Australia and South Korea during the month of April, adding 0.3 mb/d and 0.2 mb/d y-o-y, respectively, supported by improving mobility in Australia, encouraging a gasoline recovery, while strong demand for naphtha as a feedstock for steam crackers stimulated demand in South Korea. In Australia, all major product categories recoded steady gains in April, led by transportation fuels and diesel. In South Korea, product performance was mixed. Demand for naphtha and jet fuel sharply increased, diesel and gasoline were flat, while LPG and fuel oil declined compared with the same month last year.

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



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

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

By product	May 20	May 21	Change May 21/May 20 Growth	%
LPG	0.32	0.33	0.02	5.9
Naphtha	0.60	0.67	0.08	12.8
Gasoline	0.63	0.72	0.09	14.3
Jet/kerosene	0.18	0.32	0.14	77.2
Diesel	0.65	0.63	-0.01	-1.7
Fuel oil	0.18	0.17	-0.01	-7.0
Other products	0.18	0.07	-0.11	-59.4
Total	**2.73**	**2.92**	**0.20**	**7.2**

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

The most recent available preliminary oil demand data for **May** from the Japanese Ministry of Economy Trade, and Industry (METI), show rising demand by almost 0.2 mb/d y-o-y compared with an increase of 0.1 mb/d y-o-y in April. Demand was lower than in May 2019 by 0.5 mb/d, mainly due to a weaker transportation fuel recovery than expected. The May y-o-y increase in oil demand resulted from rebounding transportation fuels, coming from a low baseline, and steady mobility data. The mobility index hovered around 103%, using January 2020 as a reference.

Near-term expectations

Going forward, the recent lockdown measures by Australian authorities in an attempt to contain the spread of the Delta variant will hamper the oil demand recovery. However, the impact is anticipated to be limited to the months of June and July, and a positive rebound is projected thereafter. Generally, regional lockdown measures may occur to contain the spread of new COVID-19 variants, causing possible downside risks to the 2021 oil demand outlook. However, OECD Asia Pacific's 2021 oil demand is anticipated to rise, supported by a low baseline, along with steady petrochemical requirements and a transportation fuel recovery. Petrochemical feedstock demand is projected to encourage oil demand on the back of steady consumption for plastics and improving industrial sector requirements.

In **2022**, OECD Asia Pacific oil demand is anticipated increase by 0.2 mb/d, but remain below 2019 levels. Projections for 2022 are based on the assumption that the GDP will increase in all countries of the region, led by South Korea and Australia. Limited impact from COVID-19-related challenges on transportation fuel demand is anticipated, as herd immunity is projected to reach desired targets in 2022 amid an acceleration in vaccination rollouts. As such, gasoline is anticipated to increase the most, followed by diesel for the industrial sector. Petrochemical feedstock types LPG and naphtha are also projected to rise, supported by steady petrochemical margins and increased end-user demand.

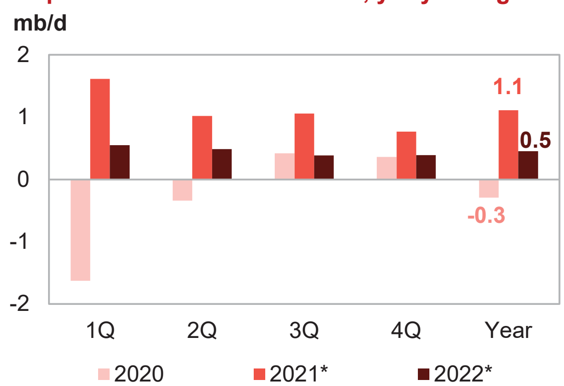
Non-OECD

China

Update on the latest developments

May oil demand data saw growth of around 1.0 mb/d y-o-y compared with a rise of 1.6 mb/d y-o-y in April, largely due to the size of the baseline decline in April and May of 2020. Additionally, when compared with May 2019, demand is nearly 0.7 mb/d higher amid healthy growth in light distillates. During May, gasoline consumption continued to increase, up by around 0.6 mb/d y-o-y boosted by improving mobility and despite marginally decreasing motor vehicle sales. Mobility exceeded pre-pandemic levels in May, posting 106% compared with 2019 after showing 100% in April, according to google and apple mobility indexes.

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



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

However, motor vehicle sales edged lower compared with May 2020, showing a drop of 2.7% after posting an increase of 9.9% y-o-y in April. It's worth highlighting that motor vehicle sales showed an increase of 13.5% in May, according to the China Association of Automobile Manufacturers. Jet fuel demand also posted gains of 0.3 mb/d y-o-y following an increase of 0.7 mb/d y-o-y in April and was at par with May 2019 levels. Improved air travel volume, especially in the domestic market, supported product recovery. Petrochemical feedstock, led by LPG, grew by roughly 0.4 mb/d y-o-y. LPG was supported by strong capacity additions at PDH plants and healthy cracker margins.

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

By product	May 20	May 21	*Change May 21/May 20* Growth	%
LPG	1.91	2.27	0.36	18.8
Naphtha	1.00	1.08	0.08	8.4
Gasoline	2.75	3.32	0.58	21.0
Jet/kerosene	0.63	0.92	0.29	45.5
Diesel	3.29	3.15	-0.14	-4.2
Fuel oil	0.65	0.63	-0.02	-3.0
Other products	2.31	2.12	-0.19	-8.2
Total	**12.53**	**13.49**	**0.96**	**7.7**

*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, oil demand growth is anticipated to rise strongly in 2H21, driven by a healthy economic outlook and mobility returning to pre-pandemic levels, with strong control expected over COVID-19 cases. The main sectors of the economy are projected to show steady growth mainly in 2H21, as the overall health of the global economy improves and the impact of a low baseline in 1H21 subsides. Generally, the oil demand outlook for 2021 is based on the assumptions of increasing gasoline demand driven by developments in the economy, rising vehicle sales compared with 2020 and improving vehicles miles travelled. In terms of products, diesel demand is projected to show growth in 2021 due to developments in industrial, construction and agricultural activity, and due to a low baseline in 2020. Additionally, demand for light distillates should record healthy gains, driven by capacity development.

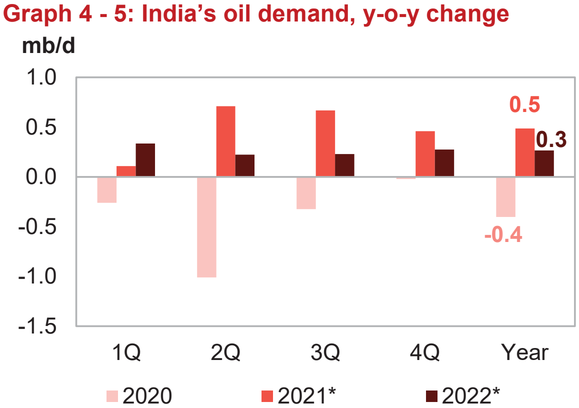
In **2022**, China's oil demand is anticipated to increase by 0.5 mb/d for total demand to exceed 2019 figures, driven by robust economic growth projections. Oil demand in the transportation and industrial sectors is anticipated to continue increasing, supported by a steady rise in mobility, a growing passenger car fleet and firm industrial activity demand. Regarding fuels, gasoline is projected to increase the most next year followed by diesel. Petrochemical end-user demand is also anticipated to supported light distillate consumption. On the other hand, fuel quality programmes targeting fewer emissions and substitution by other fuels are projected to cap oil demand growth next year.

India

Update on the latest developments

In **May**, **Indian oil demand** inched lower by 0.03 mb/d y-o-y, after rising by nearly 1.6 mb/d y-o-y in April. May oil demand data showed a decline of 0.8 mb/d compared with May 2019. A resurgence of COVID-19 cases towards the end of April and during the month of May led to regional lockdowns in various parts of the country, which included limitations on mobility and the movement of people. However, due to a large decline in oil consumption in May 2020, most petroleum products edged higher y-o-y, with the exception of the LPG and other products' categories, which declined.

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



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

Mobility plummeted in May to a record 52% of pre-pandemic levels compared with 83% for the month of April and 108% in March, according to the google and apple maps mobility index.

Transportation fuels were largely impacted by this slowdown in mobility, resulting in gasoline increasing by only 0.06 mb/d y-o-y in May, following an increase by 0.4 mb/d in April. However, gasoline was at more than 0.2 mb/d below May 2019 levels. Diesel was marginally positive as construction, trucking and agricultural activities were hit by a resurgence of COVID-19 cases and containment measures. Nevertheless, various developments, as well as early indicators for June, indicate a further recovery m-o-m. The path of the recovery is assumed to continue during 2H20, though there is still the possibility of momentum stalling should another resurgence of COVID-19 cases occur.

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

By product	May 20	May 21	Change May 21/May 20 Growth	%
LPG	0.98	0.93	-0.05	-4.9
Naphtha	0.31	0.38	0.07	22.8
Gasoline	0.52	0.58	0.06	11.6
Jet/kerosene	0.18	0.20	0.03	14.8
Diesel	1.21	1.22	0.01	0.9
Fuel oil	0.18	0.18	0.00	0.1
Other products	0.43	0.28	-0.15	-35.3
Total	**3.81**	**3.77**	**-0.03**	**-0.8**

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

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

Near-term expectations

Recent oil demand data indicate positive m-o-m momentum as May's surge in COVID-19 cases and accompanying challenges already started to ease. Improvements in mobility, industrial production activity and the resumption of overall economic activity are assumed to boost oil demand in 2H21. On the other hand, a resurgence of COVID-19 cases will pose a downside risk to oil demand until the end of the year. An acceleration in vaccination rates to reach targeted herd immunity will provide positive upside potential to oil demand over the short term. Oil demand is projected to pick up pace in 2H21, supported by diesel consumption in the construction and agricultural sectors and coming from a low 2020 baseline. Transportation fuels are anticipated to post respectable increases, though they will remain dependent on COVID-19 developments. Demand for transportation fuel is projected to account for the bulk of demand, followed by middle distillates.

For **2022**, India's oil demand growth is anticipated to rise by around 0.3 mb/d, with total volumes expected to exceed pre-pandemic levels on an annualized basis. COVID-19 containment measures are projected to improve, backed by an acceleration in vaccination rollouts, natural immunization and better treatment of COVID-19. On the economic front, the country's GDP is to increase solidly in 2022, supporting oil demand. From the product side, transportation fuels, led by gasoline, are projected to lead oil demand growth in 2022. Support will be driven by an increase in mobility through the use of private vehicles, particularly two wheelers that use gasoline as fuel. Diesel will gain strength in 2022, supported by healthy industrial, construction and agricultural activities.

Other Asia

Update on the latest developments

Oil consumption has increased in **Other Asia**, recording a rise of 0.8 mb/d y-o-y in **April** after increasing by 0.5 mb/d y-o-y in March. April data suggest a decline of 1.0 mb/d compared with April 2019, indicating that demand remained sharply lagging at 2019 levels. In Thailand, demand increased by 0.1 mb/d y-oy, Malaysia by 0.3 mb/d y-o-y, the Philippines by 0.2 mb/d, y-o-y, while Indonesia showed a marginal increase of 0.04 mb/d y-o-y. The y-o-y increase in petroleum product demand was led by diesel and transportation fuels, including gasoline and jet fuel, on the back of a low baseline and despite declining m-o-m mobility. Miles driven decreased in main consuming countries such as Indonesia, Thailand and Singapore compared with a month earlier. Diesel, which grew the most, was supported by an increase in trucking and agricultural activities, but remained largely impaired compared with 2019 levels.

Near-term expectations

Going forward, oil demand is projected to improve y-o-y, supported by heathier y-o-y industrial development and a steady recovery in mobility. However, COVID-19 and the recent prevalence of a new variant in a number of countries in the region, such as Indonesia, will pose a downside risk to the forecast going into 2H21. In terms of countries, Malaysia, Indonesia, Singapore and the Philippines are projected to account for the bulk of gains. The transportation sector is projected to lead oil demand growth in Other Asia, with gasoline being the largest contributor, followed by on-road diesel. Additionally, demand for industrial fuels, including diesel and fuel oil, will be largely dependent on the recovery in economic activities in 2021.

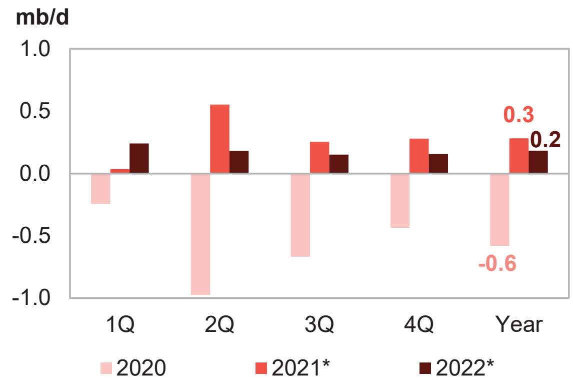
In **2022**, Other Asia's oil demand growth is expected to firmly increase by around 0.3 mb/d, with expectations based on firm GDP growth almost matching this year's levels. Indonesia and Thailand are projected to be the main contributors to growth, with respectable contributions from Malaysia, Singapore and the Philippines. Similar to other regions, transportation fuels are projected rise most in light of the projected better management of COVID-19 and improved mobility. Diesel will be the second product leading oil demand growth in 2022 and supporting the industrial sector.

Latin America

Update on the latest developments

Latin America's oil demand increased further in **April** to show a rise of 0.7 mb/d y-o-y, following an increase of more than 0.3 mb/d y-o-y in March. However, oil demand remained down compared with April 2019 by 0.3 mb/d, with transportation fuels causing most of the decline. The y-o-y increase in April was largely supported by transportation fuels recovering from last year's low baseline and some uptick in mobility data. Mobility in Brazil, the largest consuming country in the region, posted a marginal increase in April to reach 84% of pre-pandemic levels compared with 82% in March.

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



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

Gasoline and jet fuel recorded growth of around 0.2mb/d y-o-y collectively, after posting marginal growth in March. Both fuels remained largely below pre-pandemic levels and showed a drop of around 0.3 mb/d compared with April 2019.

Diesel demand was supported by a steady rebound in industrial and agricultural activities. Diesel was 0.3 mb/d higher y-o-y, even above April 2019 by around 0.1 mb/d.

In terms of regions, demand increased the most in Brazil (0.4 mb/d y-o-y) and Argentina (0.2 mb/d y-o-y), while other countries in the region posted marginal y-o-y gains.

Brazilian oil demand increased by 0.3 mb/d y-o-y in May 2021, though remaining below May 2019 levels by 0.1 mb/d. Positive increases in transportation fuels, coupled with an uptick in industrial fuel demand, supported the overall y-o-y increase. Diesel and gasoline demand grew most, supported by a pickup in the industrial sector, increased trucking movement and the low baseline of May 2020.

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

			Change May 21/May 20	
By product	**May 20**	**May 21**	**Growth**	**%**
LPG	0.22	0.23	0.00	2.1
Naphtha	0.15	0.14	0.00	-2.0
Gasoline	0.51	0.63	0.12	23.2
Jet/kerosene	0.02	0.06	0.04	181.2
Diesel	0.88	1.02	0.13	15.0
Fuel oil	0.08	0.08	0.00	1.8
Other products	0.30	0.35	0.05	15.1
Total	**2.16**	**2.50**	**0.34**	**15.6**

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

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

Near-term expectations

Going forward, an improvement in the mobility rate after a recent easing of restrictions is assumed to support demand going into 2H21. Demand is assumed to be dependent on developments around COVID-19 cases and how well the virus stays controlled through progressing vaccination programmes. However, some downside risks may pressure the oil demand recovery process, including hiccups in vaccination programmes, high unemployment rates and overall political tension, which may weigh on oil demand recovery over the short term. Generally, oil demand in the region is projected to rise as economic conditions improve, supporting industrial fuel demand. In terms of products, diesel is anticipated to grow the most, followed by gasoline, as the economy and mobility improve y-o-y.

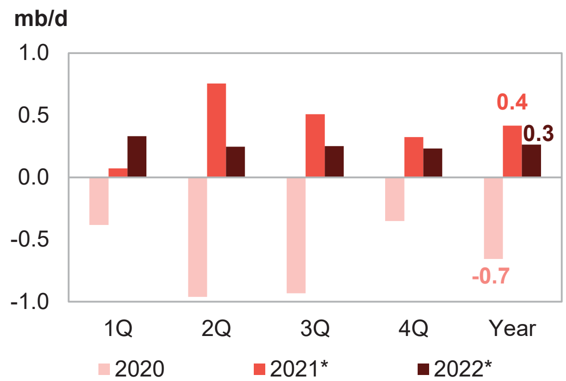
In **2022**, oil demand in Latin America is projected to increase by nearly 0.2 mb/d, but will remain below 2019 levels. Growth will be more fully determined by developments in economic activity. The largest economy in the region, Brazil, is anticipated to be the main contributor to growth, with some contribution from Argentina, Venezuela and Ecuador. Transportation fuels are projected to rise the most in 2022, stemmed by further developments in the transportation sector, as containment measures for COVID-19 improve and the overall economy gains momentum. Moreover, construction and industrial fuels are also anticipated to gain pace in 2022.

Middle East

Update on the latest developments

Middle Eastern oil demand rose by 1.0 mb/d, y-o-y in **April 2021** after increasing by around 0.7 mb/d y-o-y in March. However, compared with April 2019, demand posted a decline of some 0.1 mb/d, as transportation fuels were largely below pre-pandemic levels, though light distillate demand is already trending above pre-pandemic levels. All countries in the region recorded y-o-y growth, led by Saudi Arabia (0.4 mb/d y-o-y), Kuwait (0.2 mb/d y-o-y each) and Iraq (0.1 mb/d y-o-y). All other countries in the region also posted y-o-y gains. Transportation fuel led the recovery in April amid reduced movement restrictions and improved COVID-19 controls.

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



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

Gasoline and jet fuel demand increased by more than 0.4 mb/d y-o-y collectively, following an increase of more than 0.2 mb/d y-o-y in March. Both fuels remained well below pre-pandemic levels of more than 0.4 mb/d compared with April of 2019. The increase in diesel demand is supported by an uptick in construction and truck movements, mainly in Saudi Arabia. Cement deliveries rose by 40.8% y-o-y in April, after posting growth of 4.1% y-o-y in March. It's worth highlighting that indicators dropped by 28.8% in April 2020, as reported by the Yamama cement company and Haver analytics. This shows the continuation of a positive trend in the construction sector.

In **May**, oil demand in **Saudi Arabia** continued to increase compared with the same time last year, adding 0.3 mb/d y-o-y, making up nearly 96% of lost demand from May 2020. Rebounding gasoline accounted for most of the gains, increasing by 0.2 mb/d y-o-y after posting similar gains in April. Middle distillate demand continued to expand, as both diesel and jet fuel gained around 0.1 mb/d y-o-y, showing comparable gains to those made in April.

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

			Change May 21/May 20	
By product	**May 20**	**May 21**	**Growth**	**%**
LPG	0.04	0.05	0.01	25.0
Gasoline	0.27	0.46	0.18	67.6
Jet/kerosene	0.02	0.05	0.02	100.0
Diesel	0.42	0.46	0.04	9.0
Fuel oil	0.60	0.61	0.01	2.0
Other products	0.48	0.52	0.04	9.0
Total	**1.83**	**2.15**	**0.32**	**17.4**

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

Sources: JODI and OPEC.

Near-term expectations

Going forward, oil demand is anticipated to continue its recovery process and show respectable growth in 2021, with most consumption occurring in 2H21. On the other hand, the risk of a resurgence in COVID-19 cases and prevalence of new variants will continue to create a downside risk. Gasoline demand is anticipated to continue improving over the summer driving season, while gasoil also rose on improved industrial activity and positive developments in infrastructure projects. A slow recovery in the aviation sector will continue to challenge jet fuel consumption and remain below 2019 levels.

In **2022**, Middle East oil demand growth is anticipated to gain further strength over the current year's levels, to increase by around 0.3 mb/d amid sustained economic growth. In terms of countries, Saudi Arabia is anticipated to lead the oil demand increase in the region, driven by steady economic expectations, controlled COVID-19 cases and a healthy petrochemical sector. As a result, transportation fuels gasoline and on-road diesel, in addition to light distillates for petrochemical usage and construction fuels, are anticipated to be the products leading oil demand growth next year.

World Oil Supply

Non-OPEC liquids supply growth in 2021 (including processing gains) was revised down by a minor 26 tb/d from the previous assessment, despite upward revisions to the US and Canada, and is now expected to grow by 0.81 mb/d to average 63.76 mb/d. The oil demand projection for 2021 was revised upward due to better-than-expected data for global vaccinations, in addition to higher oil demand growth expectations for 2022, which is leading to an expected gradual recovery in non-OPEC supply. Despite prices being higher than expected, none of the US independents raised capex guidance for 2021, as most available free cash flow was used to pay debts. Nevertheless, some US independents reinvested part of their operating cash flow, some kept investment plans in the exploration and production (E&P) sector on hold, and some have gone a step further and decided to halt production at mature fields to reduce cost. The US production growth forecast has been revised up slightly by 23 tb/d, owing to higher-than-anticipated production from April until now, with growth of 0.06 mb/d y-o-y. The 2021 oil supply forecast primarily sees growth in Canada, China, Norway and Brazil, and is projected to decline in the UK, Colombia, Egypt and the Sudans.

Non-OPEC liquids production in 2022 is expected to grow by 2.1 mb/d to average 65.85 mb/d (including a recovery of 0.11 mb/d in processing gains). The supply forecast, including expected growth of OPEC NGLs, should be at 2.2 mb/d. Liquids supply in the OECD countries is expected to increase next year by 1.1 mb/d, and growth of 0.8 mb/d in the non-OECD region is anticipated. The main drivers for liquids supply growth are expected to be the US (0.74 mb/d), Russia, Brazil, Norway, Canada, Guyana and Kazakhstan, whereby the majority of the increase in the US and some other countries represents a production recovery from the 2020 oil market downturn due to curtailments, rather than growth from new projects. Nevertheless, uncertainty regarding the financial and operational aspects of US production remains high.

OPEC NGLs and non-conventional liquids production in 2021 is estimated to grow by 0.12 mb/d to average 5.17 mb/d. For 2022, it is likely to grow by 0.13 mb/d to average 5.29 mb/d. OPEC-13 crude oil production in June increased by 0.59 mb/d m-o-m to average 26.03 mb/d, according to secondary sources.

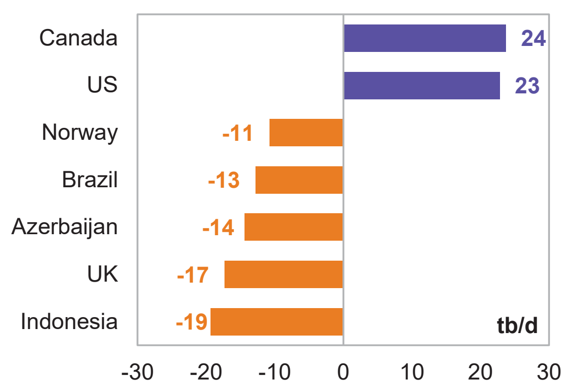
Preliminary non-OPEC liquids production in June, including OPEC NGLs, is estimated to have increased by 0.52 mb/d m-o-m to average 68.46 mb/d, up by 2.76 mb/d y-o-y. As a result, preliminary data indicates that global oil supply increased by 1.10 mb/d m-o-m to average 94.49 mb/d, down by 6.53 mb/d y-o-y.

Main monthly revisions

Non-OPEC liquids production growth in 2020 was revised down by 48 tb/d owing to a downward revision in processing gains in all quarters, as well as to historical production in Colombia and Canada, and is now estimated to have declined by 2.58 mb/d to average 62.94 mb/d for the year.

Non-OPEC liquids production growth in 2021 was revised down by 26 tb/d m-o-m and is now forecast to see growth of 0.81 mb/d (including processing gains), to average 63.76 mb/d. This was mainly due to downward revisions in production forecasts for Indonesia, the UK, Azerbaijan Brazil and Norway. Meanwhile, production forecasts for the US and Canada were revised up compared with the previous assessment, due to higher-than-expected output in 2Q21.

Graph 5 - 1: Revisions on annual supply growth forecast in 2021*, July MOMR/June MOMR

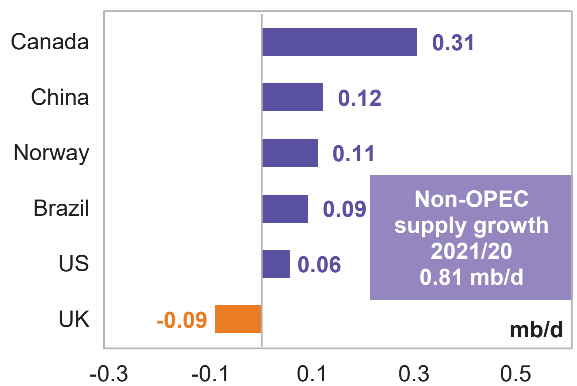


*Note: * 2021 = Forecast. Source: OPEC.*

Key drivers of growth and decline

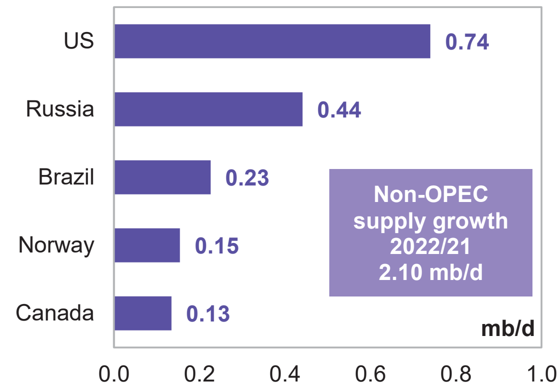
The **key drivers for non-OPEC liquids supply growth in 2021** are projected to be Canada, China, Norway, Brazil, the US, Guyana, Russia and Azerbaijan, while oil production is expected to decline mainly in the UK, Colombia, Egypt, and the Sudans.

Graph 5 - 2: Annual liquids production changes for selected countries in 2021*



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

Graph 5 - 3: Annual liquids production changes for selected countries in 2022*



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

For **2022**, the key drivers for non-OPEC supply growth are forecast to be the US, Russia, Brazil, Norway, Canada, Guyana, Kazakhstan, China, India, Oman, Qatar, the UK and Azerbaijan, while oil production will decline mainly in Egypt, Thailand, Indonesia and Malaysia.

Many institutes and agencies have forecast strong production growth for the next year, but with differing views of US and Russian production. Their near-term outlooks are mainly based on varying judgments regarding the continuation of financial and logistical circumstances in the US into 2022, and uncertainty over other countries' production.

Non-OPEC liquids production in 2021 and 2022

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

							Change 2021/20	
Non-OPEC liquids production	**2020**	**1Q21**	**2Q21**	**3Q21**	**4Q21**	**2021**	**Growth**	**%**
Americas	24.71	24.11	24.83	25.55	25.86	25.09	0.38	1.54
of which US	*17.62*	*16.64*	*17.66*	*18.10*	*18.30*	*17.68*	*0.06*	*0.32*
Europe	3.90	3.95	3.64	4.03	4.10	3.93	0.03	0.74
Asia Pacific	0.53	0.51	0.54	0.55	0.55	0.54	0.01	1.09
Total OECD	**29.15**	**28.56**	**29.01**	**30.13**	**30.51**	**29.56**	**0.41**	**1.42**
China	4.12	4.25	4.27	4.23	4.20	4.24	0.12	2.94
India	0.77	0.76	0.76	0.75	0.74	0.76	-0.01	-1.55
Other Asia	2.51	2.49	2.45	2.47	2.46	2.47	-0.04	-1.54
Latin America	6.04	5.94	6.02	6.31	6.50	6.19	0.15	2.50
Middle East	3.18	3.19	3.20	3.24	3.25	3.22	0.04	1.29
Africa	1.41	1.38	1.35	1.34	1.32	1.35	-0.07	-4.72
Russia	10.59	10.47	10.74	10.66	10.66	10.63	0.04	0.38
Other Eurasia	2.91	2.96	2.91	2.98	2.98	2.96	0.04	1.46
Other Europe	0.11	0.11	0.11	0.10	0.10	0.11	-0.01	-6.58
Total Non-OECD	**31.64**	**31.54**	**31.82**	**32.08**	**32.22**	**31.91**	**0.27**	**0.86**
Total Non-OPEC production	60.79	60.10	60.82	62.21	62.73	61.48	0.69	1.13
Processing gains	2.15	2.28	2.28	2.28	2.28	2.28	0.13	6.03
Total Non-OPEC liquids production	**62.94**	**62.38**	**63.10**	**64.49**	**65.01**	**63.76**	**0.81**	**1.29**
Previous estimate	62.89	62.41	63.06	64.30	65.10	63.73	0.84	1.33
Revision	0.05	-0.03	0.04	0.19	-0.09	0.03	-0.02	-0.04

*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	25.09	26.00	25.79	25.89	26.25	25.98	0.89	3.54
of which US	*17.68*	*18.39*	*18.44*	*18.29*	*18.55*	*18.42*	*0.74*	*4.19*
Europe	3.93	4.12	4.01	4.07	4.39	4.15	0.22	5.66
Asia Pacific	0.54	0.57	0.57	0.56	0.56	0.57	0.03	5.12
Total OECD	**29.56**	**30.69**	**30.37**	**30.53**	**31.21**	**30.70**	**1.14**	**3.85**
China	4.24	4.24	4.24	4.28	4.36	4.28	0.05	1.08
India	0.76	0.77	0.79	0.82	0.84	0.81	0.05	6.65
Other Asia	2.47	2.42	2.37	2.33	2.28	2.35	-0.12	-4.86
Latin America	6.19	6.54	6.48	6.42	6.63	6.52	0.33	5.27
Middle East	3.22	3.25	3.28	3.32	3.32	3.29	0.07	2.32
Africa	1.35	1.29	1.32	1.29	1.27	1.29	-0.05	-4.00
Russia	10.63	10.70	10.97	11.18	11.43	11.07	0.44	4.14
Other Eurasia	2.96	2.98	3.02	3.01	3.18	3.05	0.09	3.06
Other Europe	0.11	0.10	0.10	0.10	0.09	0.10	-0.01	-7.35
Total Non-OECD	**31.91**	**32.29**	**32.59**	**32.75**	**33.40**	**32.76**	**0.85**	**2.65**
Total Non-OPEC production	61.48	62.98	62.95	63.28	64.61	63.46	1.99	3.23
Processing gains	2.28	2.39	2.39	2.39	2.39	2.39	0.11	4.91
Total Non-OPEC liquids production	**63.76**	**65.37**	**65.35**	**65.67**	**67.00**	**65.85**	**2.10**	**3.29**

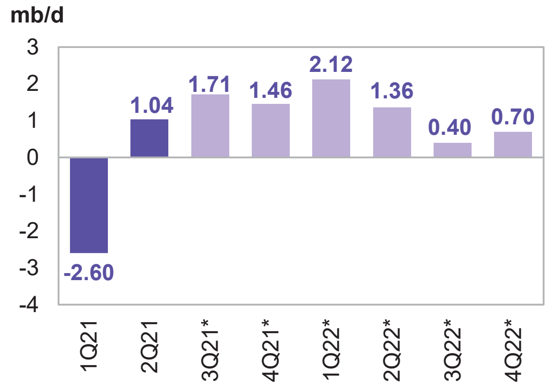
*Note: * 2021-2022 = Forecast. Totals may not add up due to independent rounding. Source: OPEC.*

OECD

OECD liquids production in 2021 is forecast to increase by 0.41 mb/d to average 29.56 mb/d. This is revised up by 21 tb/d m-o-m, owing to an upward revision of 46 tb/d in the production forecast for OECD Americas, which is now projected to grow by 0.38 mb/d to average 25.09 mb/d. OECD Europe was revised down by 21 tb/d m-o-m and is now forecast to grow by 0.03 mb/d, with an average supply of 3.93 mb/d, while oil production in OECD Asia Pacific remained unchanged and is forecast to grow by 0.01 mb/d to average 0.54 mb/d.

For **2022**, oil production in the OECD is likely to grow by 1.14 mb/d to average 30.70 mb/d, with growth from OECD Americas of 0.89 mb/d to average 25.98 mb/d. Oil production in OECD Europe and OECD Asia Pacific is anticipated to grow by 0.22 mb/d and 0.03 mb/d y-o-y to average 4.15 mb/d and 0.57 mb/d, respectively.

Graph 5 - 4: OECD quarterly liquids supply, y-o-y changes



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

OECD Americas

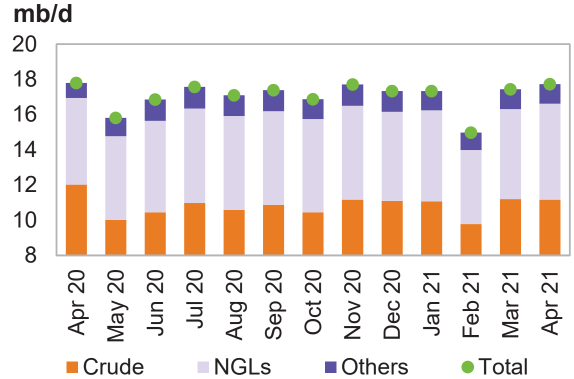
US

US liquids production in April 2021 was higher by 0.29 mb/d m-o-m on the back of outperforming NGLs to average 17.73 mb/d, almost the same level of production as seen in April 2020.

Crude oil production declined in April by 19 tb/d m-o-m to average 11.17 mb/d, a drop of 841 tb/d y-o-y. Meanwhile, production of NGLs increased by 0.33 mb/d m-o-m to average 5.44 mb/d, and other liquids, particularly ethanol, declined by 22 tb/d, to average 1.12 mb/d.

The production of crude oil, including field condensates, decreased on the Gulf Coast, Midwest, and West Coast in April m-o-m, while production in the other two PADDs increased.

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



Source: OPEC.

Crude oil output on the Gulf Coast declined, despite increasing production in Texas and New Mexico by 28 tb/d and 17 tb/d, respectively. However, oil output from the GoM declined by 92 tb/d to average 1.76 mb/d, offsetting gains elsewhere.

In the US Midwest, production in North Dakota was up by an average 6 tb/d for two consecutive months, while output in Oklahoma was down by a minor 2 tb/d. Rocky Mountain, Colorado – home to Niobrara shale – saw the largest growth in April by 31 tb/d to average 401 tb/d. Finally, on the west coast, production in Alaska declined by 7 tb/d m-o-m to average 0.45 mb/d (3.7% due to natural decline).

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

State	Mar 21	Apr 21	*Change* Apr 21/Mar 21
Colorado	370	401	*31*
Oklahoma	402	400	*-2*
Alaska	453	446	*-7*
North Dakota	1,023	1,029	*6*
New Mexico	1,155	1,172	*17*
Gulf of Mexico (GoM)	1,856	1,764	*-92*
Texas	4,763	4,791	*28*
Total	**11,188**	**11,169**	***-19***

Sources: EIA and OPEC.

Average crude oil production in the first four months of the year from the US onshore Lower 48 (excluding Alaska), declined by 1.6 m/d y-o-y. Of this, 1.3 mb/d belongs to US tight oil. Production from the GoM also declined by 0.16 mb/d in the same period. From an operational point of view, US tight crude production improvements have been slowly progressing with the help of more oil rigs coming online. More than 200 oil rigs have been added since the lowest-ever point was reached in mid-August 2020, reaching 376 on 2 July 2021, although the figure is still far from the average of 671 seen in 1Q20 before the 2Q20 downturn in drilling activities. Meanwhile, despite fracking operations and well completions having shown a sudden jump of 25% in January 2021 from December 2020, they have not seen a remarkable rising trend so far in other months. On the contrary, the withdrawal of drilled, but uncompleted, (DUC) wells from the inventory of different shale regions indicates that shale operators are still struggling against a base decline and trying keep production flat through DUC completions.

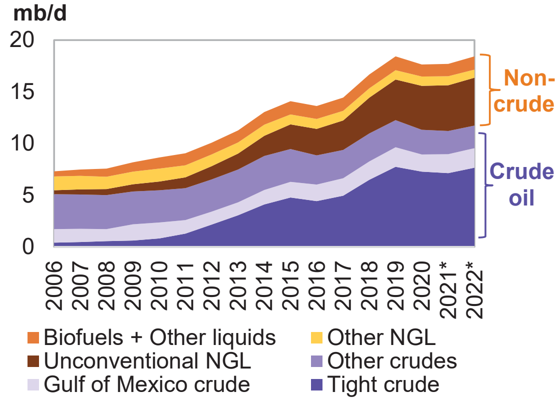
Drilling and well completion activities continued at a slow pace and are unlikely to reach y-o-y growth until 2022. The US Lower 48 – the key growth region and near-term driver for non-OPEC supply growth – is a key area that will suffer from decline in the long term. Nevertheless, US Lower 48 crude oil and NGLs supply is expected to rebound faster in 2022 from 2020-2021 lows, mainly due to favourable oil prices.

The **US liquids production growth forecast for 2021** was revised up by 23 tb/d and now is forecast to grow by 0.06 mb/d y-o-y to reach an average of 17.68 mb/d. Nevertheless, this is still 0.75 mb/d below the average supply seen in 2019.

The US liquids supply in **2022**, excluding processing gains, is anticipated to grow by 0.74 mb/d, y-o-y to average 18.42 mb/d, assuming the current level of drilling and well completion remains steady as seen in 1H21, with possible higher spending in the prolific Permian Basin, Eagle Ford and Bakken shale sites.

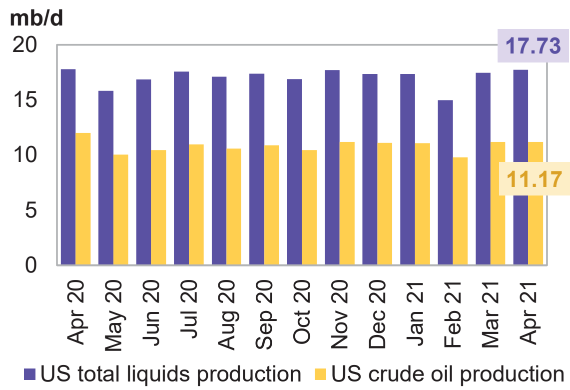
US crude oil production in 2021 is expected to decline by 0.12 mb/d to average 11.20 mb/d. However, growth of 0.15 mb/d in the GoM is expected, to average 1.81 mb/d. US tight crude and conventional crude oil will see a contraction of 0.14 mb/d and 0.13 mb/d to average 7.15 mb/d and 2.24 mb/d, respectively.

Graph 5 - 6: US liquids supply developments by component and forecast of 2021 and 2022



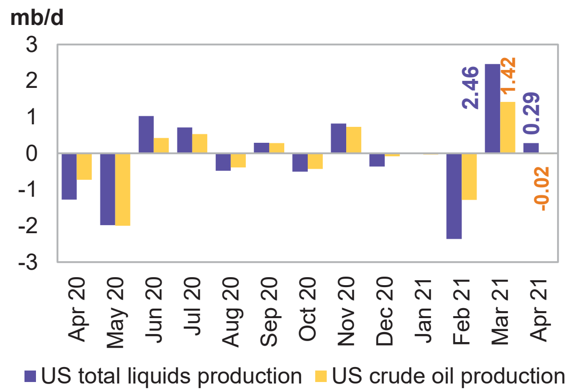
*Note: * 2021-2022 = Forecast. Source: OPEC.*

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



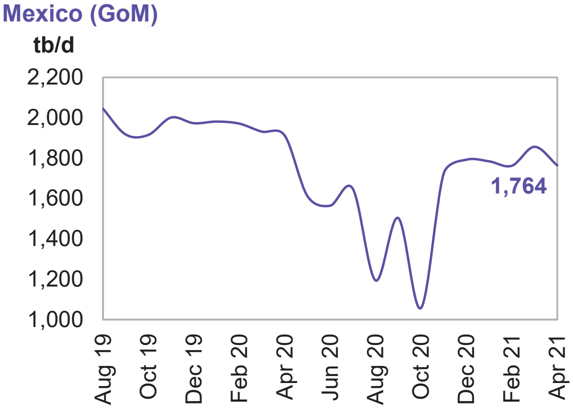
Sources: EIA and OPEC.

Contrarily, the **US NGLs production** forecast was revised up by 0.03 mb/d due to a remarkable increase of 327 tb/d in April m-o-m to average 5.44 mb/d. This represents y-o-y growth of 0.14 mb/d to average 5.30 mb/d. NGLs production, mainly from unconventional sources (around 85%), is forecast to grow to 5.42 mb/d in 2022, with the expectation of ethane rejection in gas plants remaining at the same level as in in 2021.

US biofuels and other non-conventional liquids production are forecast to recover by 0.04 mb/d in 2021 to average 1.19 mb/d. They are expected to see more recovery in 2022 by 0.08 mb/d to average 1.27 mb/d.

Crude oil production in the **GoM** in **2022** is expected to increase by 0.1 mb/d to average 1.91 mb/d, following a production recovery of 0.15 mb/d in 2021. The list of next year's assets which should bring new production on stream, apart from projects already in the ramp-up phase, includes the following five: Argos (Mad Dog Phase 2) with peak production of 120 tb/d, while Power Nap, Manuel, Samurai and Khaleesi are projected to produce around 45 tb/d in 2022, the first year of production. It is worth noting that production in the US GoM is usually affected during hurricane season. This took place in 2020 and recent predictions by the National Oceanic and Atmospheric Administration (NOAA) see a 60% chance of another active Atlantic hurricane season in 2021. Production from the GoM could be impacted by around 100 tb/d in 3Q21.

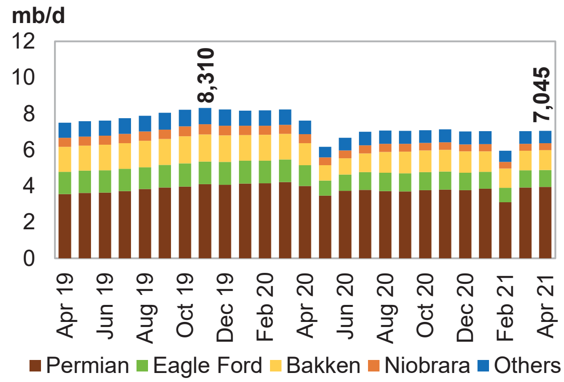
Graph 5 - 9: US crude oil production in Gulf of Mexico (GoM)



Source: EIA.

US tight crude output in April increased by an estimated 15 tb/d m-o-m according to EIA estimates to average 7,045 tb/d, 567 tb/d lower than in the same month a year earlier. The main m-o-m increase in US tight crude output from shale and tight formations through horizontal wells came from the Bakken shale in the Williston Basin by 15 tb/d m-o-m to average 1,106 tb/d, along with the Permian, Midland and Delaware Basins in Texas and New Mexico, which were up by 34 tb/d to average 3,951 mb/d, though lower by 50 tb/d y-o-y. Tight crude output at Eagle Ford declined by 16 tb/d to average 1936 tb/d; output in the Niobrara dropped by 8 tb/d to average 371 tb/d; while in other regions production fell m-o-m by 9 tb/d to average 680 tb/d.

Graph 5 - 10: US tight crude output breakdown



Sources: EIA, Rystad Energy and OPEC.

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	7.29	-0.46	7.15	-0.14	7.65	0.50
Gulf of Mexico crude	1.66	-0.24	1.81	0.15	1.91	0.10
Conventional crude oil	2.37	-0.23	2.24	-0.13	2.17	-0.07
Total crude	11.31	-0.93	11.20	-0.12	11.73	0.53
Unconventional NGLs	4.26	0.33	4.44	0.18	4.62	0.19
Conventional NGLs	0.90	0.00	0.86	-0.05	0.80	-0.06
Total NGLs	5.16	0.34	5.29	0.13	5.42	0.13
Biofuels + Other liquids	1.15	-0.20	1.19	0.04	1.27	0.08
US total supply	**17.62**	**-0.80**	**17.68**	**0.06**	**18.42**	**0.74**

*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 by 0.12 mb/d and 0.38 mb/d, to average 3.98 mb/d and 4.36 mb/d, respectively. Bakken shale production fell by 0.23 mb/d in 2020 and is expected to contract by 70 tb/d in 2021, while growth of 68 tb/d for 2022 is anticipated, to average 1.18 mb/d. Eagle Ford in New Mexico is also a prolific shale region that is expected to grow this year and next by 18 tb/d and 90 tb/d to average 1.07 mb/d and 1.16 mb/d, respectively. Production in other shale plays is not expected to show growth in 2021 or 2022, given current drilling and completion activities. US tight crude saw a contraction of 461 tb/d in 2020 and is expected to see a y-o-y decline of 136 tb/d this year, but is forecast to grow by 0.5 mb/d in 2022 to average 7.65 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	3.86	0.14	3.98	0.12	4.36	0.38
Bakken shale	1.18	-0.23	1.11	-0.07	1.18	0.07
Eagle Ford shale	1.05	-0.19	1.07	0.02	1.16	0.09
Niobrara shale	0.45	-0.06	0.42	-0.03	0.40	-0.02
Other tight plays	0.74	-0.12	0.56	-0.18	0.54	-0.02
Total	**7.29**	**-0.46**	**7.15**	**-0.14**	**7.65**	**0.50**

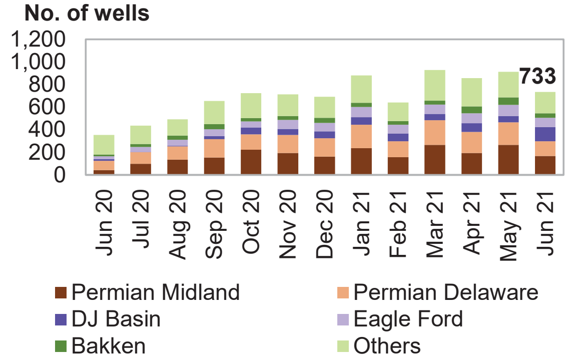
*Note: * 2021-2022 = Forecast. Source: OPEC.*

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

In terms of identified **US oil and gas fracking operations** by region, Rystad Energy reported that 733 wells started fracking in June. This preliminary number is based almost exclusively on analysis of high-frequency satellite data.

The number of frac starts in January touched 860, a jump of 28% from December. The total then plunged by 27% in February as freezing weather conditions halted operations across much of Texas and parts of New Mexico. March saw a renewed 45% surge with 927 frac jobs, the highest level seen since the same month a year earlier at 970 starts.

Graph 5 - 11: Fracked wells count per month

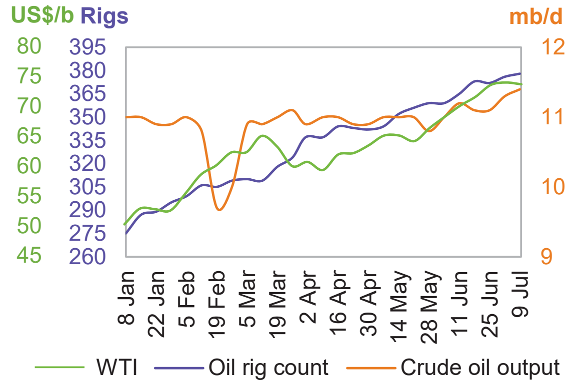


Note: June 2021 = Preliminary data.
Sources: Rystad Energy Shale Well Cube and OPEC.

Total **US active drilling rigs** rose by 4 units w-o-w to 479 rigs, according to the Baker Hughes's weekly survey on 9 July. This includes 461 active onshore rigs, 17 offshore rigs and one rig in inland waters.

The **US oil rig count** increased by 19 units to 378 rigs since the last MOMR for the week ending 4 June, higher by 1,197 rigs y-o-y. The **gas rig count** reached 101 rigs, higher by two rigs w-o-w and up by 26 units compared with a year ago. Rigs targeting oil in the Permian Basin remained unchanged at 237, up by 112 y-o-y. The total rig count is 86% higher than this time last year and up nearly 50% since falling to a record low of 244 in August 2020.

Graph 5 - 12: US weekly rig count vs US crude oil output



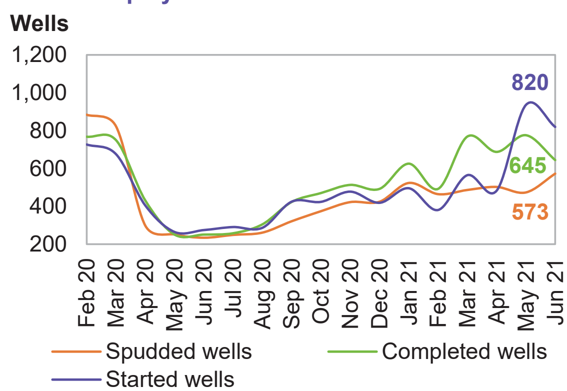
Sources: Baker Hughes, EIA and OPEC.

With the current trend in the weekly increase of drilling rigs, which is a good indicator for predicting future oil production, it does not seem that oil production in onshore fields will increase in 2021 compared to the previous year, and so long as the slope of this trend does not change, crude oil output will continue to grow steadily, but slowly in 2022, unless this trend accelerates significantly. Horizontal wells increased by 213 to now reach 433, and the overall drilling outlook remains healthy, but not sufficient to support strong growth.

With regard to **drilling and completion (D&C) activities for spudded, completed and started wells** in all US shale plays, 573 horizontal wells were spudded in June, compared with 932 in June 2019 when D&C was "normal". That is also a rise of 99 wells m-o-m.

In the same month, preliminary data indicates a lower number of completed and started wells at 645 and 820, respectively, m-o-m. The data shows that in total 3,026 horizontal wells were spudded in all shale regions. At the same time, 3,997 wells were completed, including 1,236 DUCs. Finally, on 1 July Rystad Energy reported that 3,681 wells had started production in 1H21.

Graph 5 - 13: Spudded, completed and started wells in US shale plays

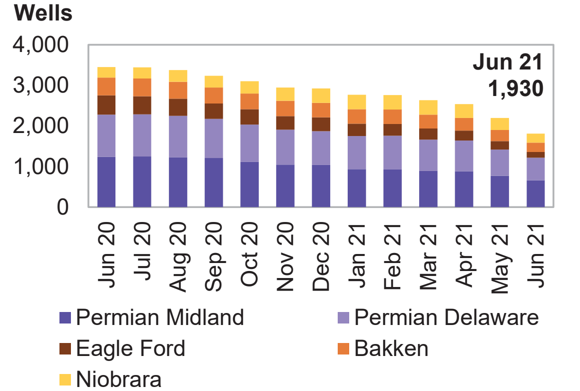


Sources: Rystad Energy and OPEC.

The number of withdrawn **DUCs in June** from inventories in different regions increased by 396 wells m-o-m (preliminary data) following the withdrawal of 327 DUCs in May. Out of 396 DUCs, 203 wells were completed in the Permian Basin, 64 in Eagle Ford, 44 in Bakken, 77 in Niobrara and 8 in other shale regions.

As a result, it is estimated that there are 1,930 economically feasible DUCs (wells which have been drilled over the past two years) which have remained in inventory by 1 July, according to the latest Rystad Energy data.

Graph 5 - 14: US horizontal DUC count by shale play

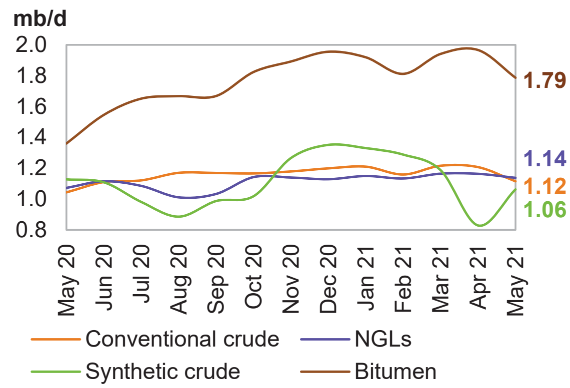


Sources: Rystad Energy and OPEC.

Canada

Canada's liquids production in May showed a decline by 0.06 mb/d m-o-m to 5.14 mb/d, following the continuation of maintenance and following a m-o-m drop of 0.34 mb/d in April. However, this was less than the planned curtailment assumed in the forecast. In May, while production of crude bitumen, conventional crude and NGLs declined by 179 tb/d, 92 tb/d, and 26 tb/d, respectively, some 233 tb/d of synthetic crude was recovered from upgraders m-o-m during the seasonal roundabout to average 1.06 mb/d. Thus, total liquids output was higher than expected by 62 tb/d. Hence, the forecast was revised up for 2Q21, leading to an overall upward revision of 24 tb/d in Canadian liquids output in 2021. This is now expected to grow by 0.31 mb/d y-o-y, which would make Canada the leader in non-OPEC supply growth for the current year.

Graph 5 - 15: Canada's monthly production development



Sources: National Energy Board and OPEC.

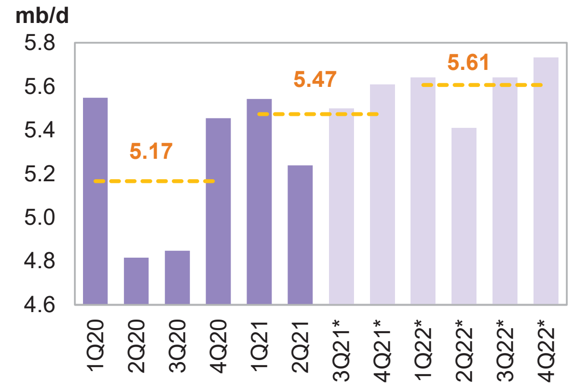
Canada's total oil sands output, mainly in Alberta, rose to 2.85 mb/d in May, up by 54 tb/d m-o-m and 0.36 mb/d y-o-y, but down by 0.4 mb/d compared with January 2021, due to maintenance schedules. Despite heavier-than-normal turnarounds at a number of oil sands projects in 1H21, the forecast is for Canada's total liquids to reach new record highs of 5.61 mb/d in 4Q21. Production will come from the expansion of existing, rather than new, projects. The lifting of Canadian government-ordered curtailments and the restart of oil sands expansion projects that were deferred in 2020 are the main drivers for increasing production in 2021.

Despite the US revoking the presidential permit authorizing construction of the Keystone XL pipeline in January 2021, which would have expanded Canadian crude oil capacity to the US by 830 tb/d, Canada's pipeline export capacity is projected to be adequate through to the end of 2025. It is worth noting that Enbridge's Line 3 replacement, with a capacity of 370 tb/d, will come online at the end of 2021. At the same time, the TransMountain expansion project, with a potential of 590 tb/d, will start transferring oil in 2022. These projects include additional expansion and optimization to Enbridge's existing pipeline system, which can add a total of 400 tb/d of export capacity.

For **2022**, Canadian production is forecast to gradually increase amid higher demand in the coming months, with output expected to average 5.61 mb/d, representing y-o-y growth of 0.13 mb/d.

Incremental production will come mainly from Alberta's oil sands, which saw average output of 3.16 mb/d in 1Q21 before the beginning of turnarounds.

Graph 5 - 16: Canada's quarterly liquid productions



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

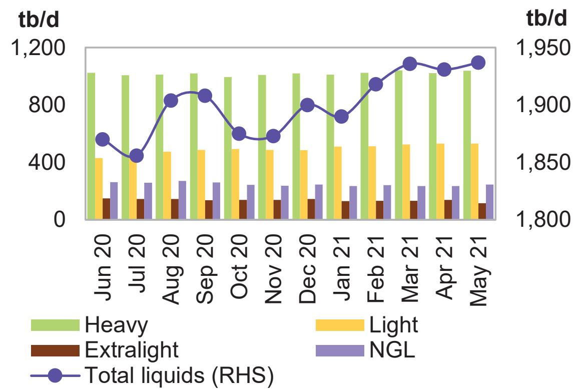
Mexico

Mexico's liquids output in May rose by a minor 6 tb/d m-o-m to average 1.94 mb/d, up by 0.05 mb/d y-o-y, following an increase of 11 tb/d in NGLs output to average 245 tb/d, while crude oil declined by a minor 5 tb/d to average 1.69 mb/d, according to national oil company PEMEX.

For **2021**, liquids production in Mexico is forecast to grow by 0.02 mb/d to average 1.93 mb/d. Production from new projects Ichalkil-Pokoch and Hokchi is supported by production ramp-ups from Integral Ek-Balam, Ixtal-Manik, Crudo Ligero Marino, Litoral De Tabasco, Chalabi and Mulach, all located offshore. They will also be ramping up into 2022.

For **2022**, liquids production is forecast to grow by 0.02 mb/d to average 1.95 mb/d through another two new projects, Amoca FFD (Miamte) with peak capacity of 55 tb/d and Mizton FFD with peak capacity of 26 tb/d, to be actualized in 2025 and 2024, respectively

Graph 5 - 17: Mexico's monthly liquids and crude production by type



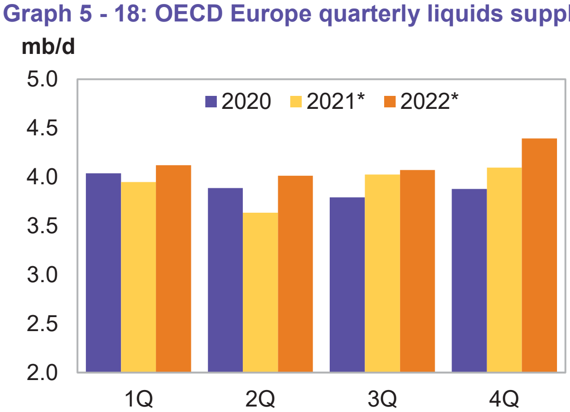
Sources: PEMEX and OPEC.

OECD Europe

OECD Europe's liquids production in 2021 is projected to grow by only 0.03 mb/d to average 3.93 mb/d, owing to a production contraction in the UK of 0.09 mb/d and a slowdown in Norway's production compared with remarkable growth of 0.26 mb/d in 2020. Oil production in Denmark will see a minor decline of 0.01 mb/d, while other OECD Europe will see growth of 0.02 mb/d. The early summer turnaround at the Troll and the Forties pipeline systems (FPS) bring with them a seasonally large drop in North Sea volumes in May and June, with production averaging about 2.43 mb/d.

For **2022**, production is expected to surge to 4.15 mb/d through continued production ramp-ups in Norway and the UK, representing y-o-y growth of 0.22 mb/d for the region.

Graph 5 - 18: OECD Europe quarterly liquids supply



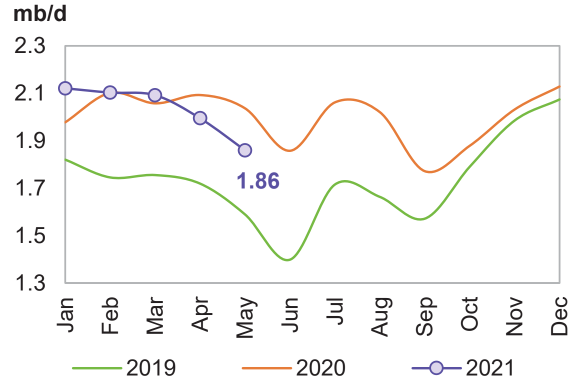
*Note: * 2021-2022 = Forecast. Source: OPEC.*

Norway

Norwegian crude production in May fell by 61 tb/d m-o-m to 1.65 mb/d. Production of NGLs and condensate also declined by 74 tb/d m-o-m to average 0.21 mb/d following maintenance at some gas condensate fields. As a result, total liquids dropped by 0.14 mb/d in May m-o-m to average 1.86 mb/d.

For **2021**, the growth forecast has been revised down by 11 tb/d m-o-m, based on lower output than expected for 2Q21. Production is now expected to average 2.11 mb/d, with growth of 0.11 mb/d y-o-y. In terms of new projects for 2021, Martin Linge is planned for July and production is expected to reach 53 tb/d. Production from Johan Sverdrup phase-1, which passed the 500 tb/d level in January 2021, is expected to reach 535 tb/d in July and continue at this level until the end of year.

Graph 5 - 19: Norway's monthly liquids output



Sources: NPD and OPEC.

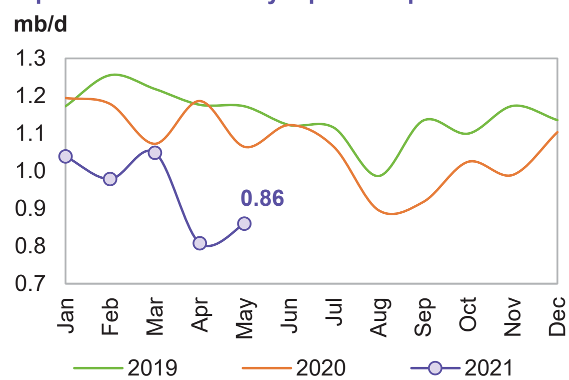
For **2022**, Norwegian liquids production is expected to grow by 0.15 mb/d to average 2.27 mb/d. There are plenty of small-to-large projects planning to start up in 2022. "Norway's tax incentives initiated last year in response to the pandemic are working as intended, with investment increasing in oil and gas projects, especially those tied to existing infrastructure," ESAI Energy reported. Part of John Sverdrup phase-2 is expected to come onstream in December 2022. A number of new crude oil projects, including Nova, Hod (redevelop), Njord Future, Bauge, and Fenja-phase 1 will start production in 2022; they are located offshore.

UK

UK liquids production in **May** was up by 0.05 mb/d m-o-m to average 0.86 mb/d on the back of increasing crude oil output by 49 tb/d to average 0.76 mb/d, lower by 0.21 mb/d y-o-y. NGLs output was almost flat at 0.06 mb/d m-o-m.

Average liquids output in the first five months of the year was at 0.95 mb/d, indicating a decline of 0.14 mb/d y-o-y. UK production was curbed by relatively high levels of maintenance work. The decline was even deeper regarding crude oil production, with output down by 17%, or 170 tb/d, over a year ago. Some maintenance programmes have been deferred from last year, including the planned three-week shutdown of the major (300 tb/d) Forties Pipeline System.

Graph 5 - 20: UK monthly liquids output



Sources: Department of Energy & Climate Change and OPEC.

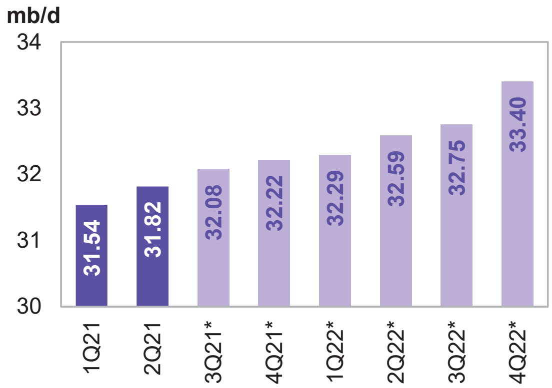
For **2021**, UK oil production is forecast to see a deep contraction of 0.09 mb/d to average 0.98 mb/d due to several outages on the back of maintenance during 1H21.

For **2022**, UK liquids production is forecast to grow by 0.04 mb/d to average 1.01 mb/d following two consecutive years of decline. Production ramp-ups will be seen in some small fields, as well as the start-up of Penguins oil field (Redevelop) and Buzzard Phase 2 (20/06-3), each with a peak capacity of 30 tb/d. Both are expected to peak in 2024 and are the drivers for annual growth in 2022.

Non-OECD

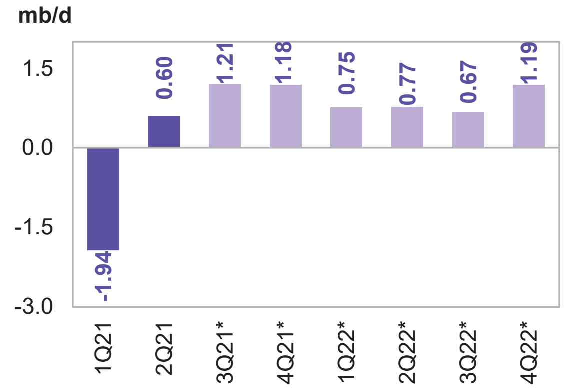
Non-OECD liquids production for 2021 is forecast to grow by 0.27 mb/d to average 31.91 mb/d. Production in China is expected to grow by 0.12 mb/d to average 4.24 mb/d. The key driver remains Latin America, with a y-o-y forecast growth of 0.15 mb/d to average 6.19 mb/d. Oil production is also forecast to increase in the Middle East by 0.04 mb/d to average 3.22 mb/d, while production is seen to decline in Africa and other Asia by 0.07 mb/d to average 1.35 mb/d, and 0.04 mb/d to average 2.47 mb/d, respectively. Oil production in Russia, and other Eurasia is projected to return to positive territory, with minor growth of 0.04 mb/d for each, while other Europe is anticipated to decline by 0.01 mb/d to average 0.11 mb/d in 2021.

Graph 5 - 21: Non-OECD quarterly liquids supply



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

Graph 5 - 22: Non-OECD quarterly liquids supply, y-o-y changes



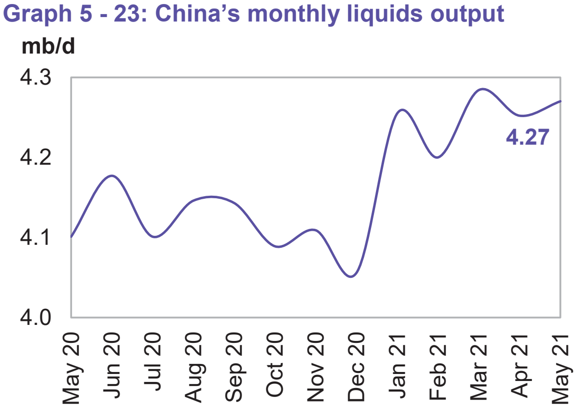
*Note: * 3Q21-4Q22 = Forecast. Source: OPEC.*

For **2022**, liquids production in non-OECD countries is forecast to grow by 0.85 mb/d to average 32.76 mb/d. China and India are expected to grow by 0.05 mb/d each to average 4.28 mb/d and 0.81 mb/d, respectively. The key drivers will be Russia, Latin America, other Eurasia and the Middle East.

China

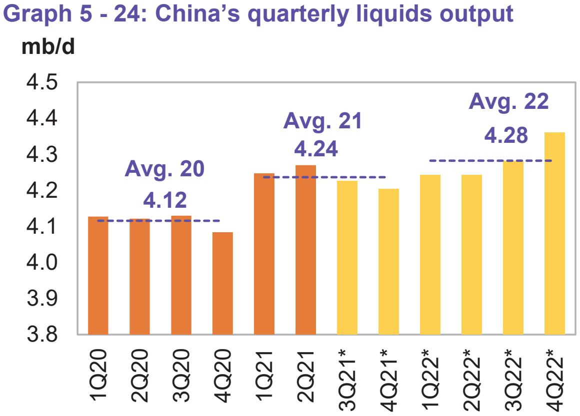
China's **liquids production** in **May** was up by 0.02 mb/d m-o-m to average 4.27 mb/d, higher by 0.17 mb/d y-o-y, according to official data. Crude oil output in May increased by 18 tb/d to average 4.01 mb/d, up by 134 tb/d y-o-y. Preliminary liquids production data in **June** indicates a m-o-m increase of 0.02 mb/d to average 4.29 mb/d. Overall production during the first five months of 2021 has been 3%, or 110 tb/d, higher than the corresponding period in 2020.

Graph 5 - 23: China's monthly liquids output



Sources: CNPC and OPEC.

Graph 5 - 24: China's quarterly liquids output



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

For **2021**, China's liquids supply is projected to see growth of 0.12 mb/d to average 4.24 mb/d. According to a list of new projects for the current year, three projects (namely Liuhua 16-2, Luda 21-2 and Caofeidian 6-4), all offshore, should start production in 2021.

For **2022**, y-o-y growth of 0.05 mb/d is anticipated to average 4.28 m/d. For the next year, two other offshore 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 on stream under CNNOC.

Latin America

Latin America's total liquids supply in May was down by 0.06 mb/d m-o-m to average 5.97 mb/d, mainly on the back of decreasing production in Brazil and Colombia. However, liquids output was up by 0.36 mb/d y-o-y.

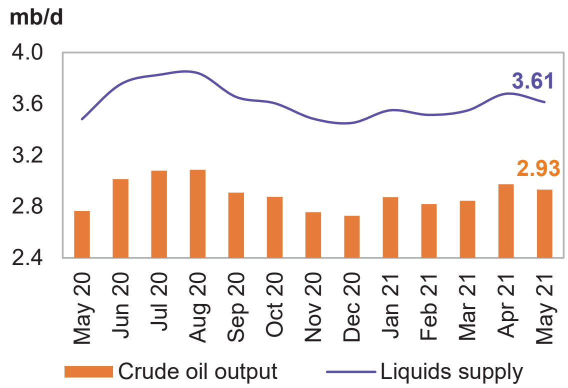
For **2021**, liquids production has been revised down by 18 tb/d m-o-m and is projected to grow by 0.15 mb/d y-o-y to average 6.19 mb/d. Oil production in Brazil, Guyana, Ecuador, Argentina and Peru is forecast to increase, while declines are expected in Colombia and other countries in the region. Production in Ecuador is projected to recover by 0.03 mb/d after outages seen in 2020 to average 0.52 mb/d. Following a national strike and protests across Colombia, crude oil production was impacted through May and June by 60 tb/d vs 1Q21. If protests escalate or go on beyond June, production will continue to drop during 3Q21 as well. Oil production is likely to decline in Colombia by 0.03 mb/d, which has been revised down by 0.05 mb/d m-o-m. Production from the offshore Liza-1 project in Guyana returned to 0.11 mb/d in May after the operator fixed issues in offshore platform's gas compressor in April. Oil production in Liza phase-1 in Guyana is expected to average 0.12 mb/d in 2021, with y-o-y growth of 0.04 mb/d. In Argentina, oil production is forecast to grow by 0.02 mb/d to average 0.68 mb/d. This should come mainly in the form of tight crude from Vaca Muerta, which is expected to grow by 29 tb/d in 2021 to average 137 tb/d. However, possible higher natural declines in mature fields may impact anticipated overall growth for the year.

For **2022**, Latin America's total liquids supply forecast is projected to grow by 0.33 mb/d y-o-y to average 6.52 mb/d. One of the key drivers is Brazil, with expected growth of 0.23 mb/d, including biofuels, to average 3.99 mb/d. Guyana would be the second country in the region experiencing growth next year, through the start-up of Liza phase-2. Oil production in other countries in the region will decline, or see only minor growth.

Brazil

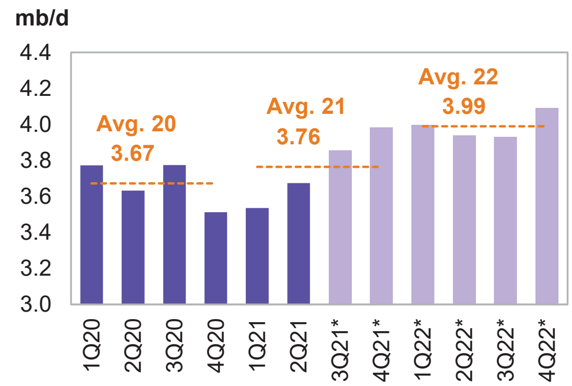
Brazil's crude oil output in May fell by 0.04 mb/d m-o-m to average 2.93 mb/d, as total production in pre-salt areas declined by 0.18 mb/d. Crude oil output averaged 2.89 mb/d in the first five months of the year, down 79 tb/d y-o-y. In May, total liquids production was pegged at an average of 3.61 mb/d, including biofuels and NGLs, up by 0.13 mb/d y-o-y. It is estimated that crude oil output in June already passed the 3 mb/d level. Higher production by 0.3 mb/d in 2H21 is expected through continuation of the ramp-up of Búzios and Atapu. Moreover, the Sépia field (formerly Northeast Tupi), which is located in the pre-salt horizon in the Santos Basin, is planned to start production in 2H21. Nevertheless, Brazilian liquids supply in 2021, including biofuels, is unlikely to see growth of more than 0.09 mb/d y-o-y, to average 3.8 mb/d, due to weaker-than-expected output in 1H21.

Graph 5 - 25: Brazil's monthly crude oil and liquids supply



Sources: ANP, Petrobras and OPEC.

Graph 5 - 26: Brazil's quarterly liquids output



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

For **2022**, crude oil production is expected to increase through three new project start-ups. Mero-1 (Guanabara) which was initially planned to start up in 2021, but was deferred to the next year due to delays in delivery of the floating production storage and offloading unit (FPSO). A final investment decision for the development of the Mero-1 area was reached in December 2017. The FPSO Guanabara, to be deployed in the Mero-1 area, is currently under construction. The processing capacity of the FPSO will be 180 tb/d of oil and 12 mcm of gas per day. The water injection capacity will be 225 tb/d, while the oil storage capacity will be 1.4 mb. The FPSO will be connected to 17 wells.

Moreover, production in Brazil will be boosted through the restart of the Peregrino (South West) field, after operator Equinor halted production as a preventative measure to carry out safety inspections due to operational issues in a gas turbine and a riser in April 2020. Phase 2 will also be brought on stream in 2022 and will be developed through an additional wellhead platform, with production tied back to the existing FPSO.

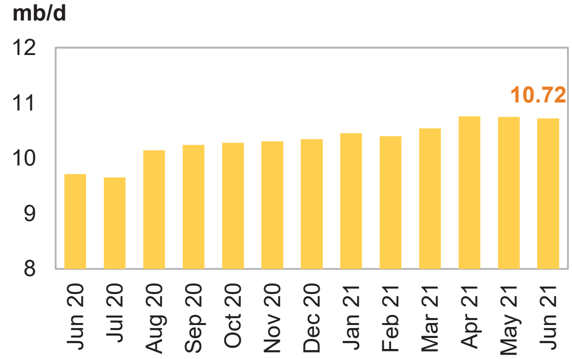
Brazil liquids supply forecast, including biofuels, is set to increase by 0.23 mb/d y-o-y in 2022 to average 3.99 mb/d.

Russia

Preliminary data for **Russia's liquids production in June** shows a decline of 0.03 mb/d m-o-m to reach an average of 10.72 mb/d, higher by 1.0 mb/d y-o-y. Hence, the second quarter is now estimated at 10.74 mb/d, up by 0.27 mb/d q-o-q. Crude oil production in June averaged 9.5 mb/d according to the Ministry of Energy, representing an increase of 0.81 mb/d y-o-y. Total condensate and NGLs output from gas condensate fields was pegged at 1.22 mb/d in 2Q21, up by 14 tb/d q-o-q.

Annual liquids production in **2021** is forecast to increase by a minor 0.04 mb/d y-o-y to average 10.63 mb/d, following a contraction of 1.0 mb/d in 2020.

Graph 5 - 27: Russia's monthly liquids production and forecast



Sources: Nefte Compass, The Ministry of Energy of the Russian Federation and OPEC.

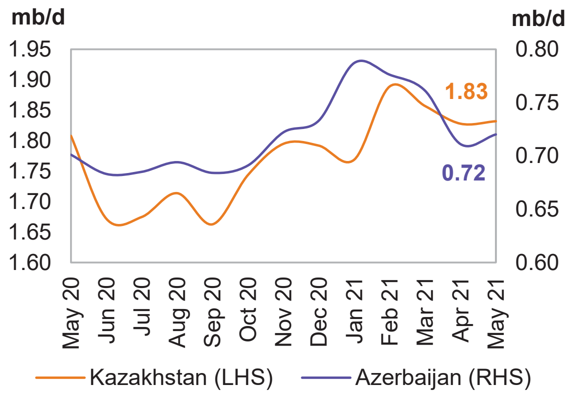
Caspian

Kazakhstan & Azerbaijan

Liquids production in **Kazakhstan** was flat in **May** at 1.83 mb/d, almost unchanged from a month ago. However, crude oil production for the month was down by 15 tb/d to average 1.48 mb/d. In contrast, NGLs output was up by 19 tb/d to average 354 tb/d in May. Kazakhstan liquids output is forecast to grow by 0.02 and 0.06 mb/d in 2021 and 2022 to average 1.84 mb/d and 1.90 mb/d, respectively.

Azeri liquids production in May rose by a minor 9 tb/d to average 0.72 mb/d, up by 0.02 mb/d y-o-y. While crude oil output increased to 0.59 mb/d, 0.01 mb/d higher than in April, NGLs production was flat at 0.13 mb/d. Azerbaijan NGLs output in 2Q21 was down from an average of 0.19 mb/d in 1Q21 to 0.13 mb/d. Azerbaijan's liquids supply is expected to show growth of 0.04 mb/d and 0.03 mb/d in 2021 and 2022 to average 0.77 mb/d and 0.80 mb/d, respectively.

Graph 5 - 28: Liquids monthly output in Caspian



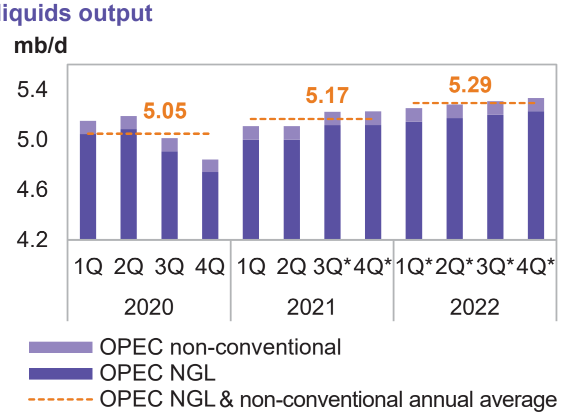
Sources: Nefte Compass and OPEC.

OPEC NGLs and non-conventional oils

OPEC NGLs and non-conventional liquids are estimated to grow by 0.12 mb/d in **2021** 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 will remain unchanged at 0.11 mb/d.

Graph 5 - 29: OPEC NGLs and non-conventional liquids output



*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 26.03 mb/d in June 2021, higher by 0.59 mb/d m-o-m. Crude oil output increased mainly in Saudi Arabia, UAE, Angola, IR Iran and Kuwait, while production decreased primarily in Iraq, Nigeria and Gabon.

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

Secondary sources	2019	2020	4Q20	1Q21	2Q21	Apr 21	May 21	Jun 21	Change Jun/May
Algeria	1,022	897	857	870	886	870	886	903	*17*
Angola	1,401	1,248	1,164	1,135	1,111	1,140	1,080	1,115	*36*
Congo	324	288	273	271	265	270	259	265	*6*
Equatorial Guinea	117	115	112	107	111	115	109	110	*2*
Gabon	208	195	191	185	183	197	179	173	*-7*
IR Iran	2,356	1,988	2,003	2,214	2,443	2,422	2,437	2,470	*33*
Iraq	4,678	4,049	3,817	3,881	3,944	3,947	3,948	3,938	*-10*
Kuwait	2,687	2,432	2,293	2,327	2,356	2,326	2,358	2,383	*25*
Libya	1,097	367	911	1,175	1,152	1,136	1,157	1,163	*7*
Nigeria	1,786	1,579	1,434	1,410	1,420	1,455	1,407	1,399	*-8*
Saudi Arabia	9,794	9,182	8,962	8,445	8,503	8,122	8,481	8,906	*425*
UAE	3,094	2,802	2,515	2,610	2,644	2,613	2,640	2,680	*40*
Venezuela	796	500	408	517	507	481	510	529	*19*
Total OPEC	**29,361**	**25,642**	**24,940**	**25,147**	**25,524**	**25,092**	**25,448**	**26,034**	***586***

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	4Q20	1Q21	2Q21	Apr 21	May 21	Jun 21	Change Jun/May
Algeria	1,023	899	862	874	886	867	891	901	*10*
Angola	1,373	1,271	1,186	1,136	1,125	1,177	1,125	1,073	*-52*
Congo	329	300	285	275	266	264	266	268	*2*
Equatorial Guinea	110	114	106	104	99	98	99	100	*2*
Gabon	218	207	178	183	179	184	171	183	*12*
IR Iran	..	..	..	..	..	..	..	..	*..*
Iraq	4,576	3,997	3,796	3,846	3,890	3,930	3,879	3,862	*-17*
Kuwait	2,678	2,438	2,293	2,327	2,355	2,327	2,355	2,384	*29*
Libya	..	389	972	1,214	1,213	1,168	1,227	1,243	*16*
Nigeria	1,737	1,493	1,301	1,404	1,343	1,372	1,344	1,313	*-31*
Saudi Arabia	9,808	9,213	8,975	8,473	8,535	8,134	8,544	8,928	*383*
UAE	3,058	2,779	2,501	2,610	2,645	2,613	2,641	2,681	*40*
Venezuela	1,013	569	463	533	556	452	582	633	*51*
Total OPEC	**..**	**..**	**..**	**..**	**..**	**..**	**..**	**..**	***..***

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

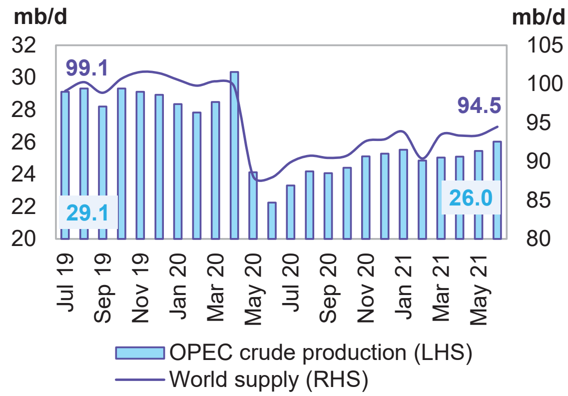
World oil supply

Preliminary data indicates that **global liquids production in June** increased by 1.10 mb/d to average 94.49 mb/d, compared with the previous month.

Non-OPEC liquids production (including OPEC NGLs) increased in June by 0.52 mb/d compared with the previous month to average 68.46 mb/d, higher by 2.76 mb/d y-o-y. Preliminary increases in production over June were mainly driven by the OECD, which saw 0.46 mb/d m-o-m more production compared with an increase of only 0.08 mb/d in non-OECD countries, including participants in the DoC, as production had already been adjusted in May.

The **share of OPEC crude oil in total global production** decreased by 0.3 pp to 27.6% in June compared with the previous month. Estimates are based on preliminary data from direct communication for non-OPEC supply, OPEC NGLs and non-conventional oil, while estimates for OPEC crude production are based on secondary sources.

Graph 5 - 30: OPEC and world oil supply



Source: OPEC.

Commercial Stock Movements

Preliminary May data sees total OECD commercial oil stocks up by 8.3 mb m-o-m. At 2,934 mb, they were 276.9 mb lower than the same time one year ago, 86.6 mb lower than the latest five-year average, and 21.7 mb below the 2015-2019 average. Within the components, crude and product stocks were up by 1.1 mb and 7.2 mb, m-o-m, respectively.

At 1,466 mb, OECD crude stocks stood 60.8 mb below the latest five-year average and 32.5 mb below the 2015-2019 average.

At 1,468 mb, OECD product stocks exhibited a deficit of 25.9 mb below the latest five-year average, but were 10.8 mb above the 2015-2019 average.

In terms of days of forward cover, OECD commercial stocks fell m-o-m by 0.8 days in May to stand at 64.2 days. This is 13.4 days below May 2020 levels, 0.8 days below the latest five-year average, but 2.4 days above the 2015-2019 average.

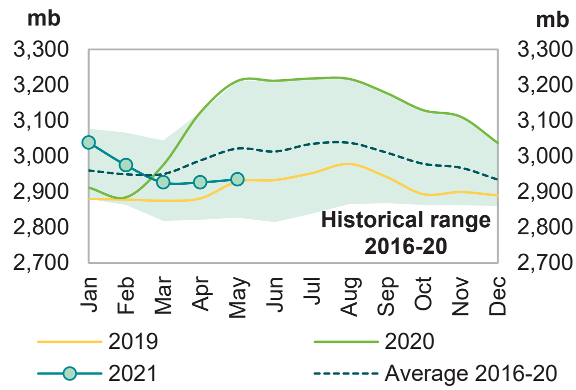
Preliminary data for June showed that total US commercial oil stocks rose slightly m-o-m by 0.4 mb to stand at 1,278 mb. This is 174.6 mb, or 12.0%, lower than the same month a year ago, and 50.3 mb, or 3.8%, below the latest five-year average. Crude stocks fell m-o-m by 26.9 mb, while product stocks rose by 27.4 mb.

OECD

Preliminary May data sees **total OECD commercial oil stocks** up by 8.3 mb m-o-m. At 2,934 mb, they were 276.9 mb lower than the same time one year ago and 86.6 mb lower than the latest five-year average.

Within the components, crude and product stocks were up by 1.1 mb and 7.2 mb, m-o-m, respectively. Total commercial oil stocks in May rose in OECD Asia Pacific and OECD Europe, while they fell in OECD Americas.

Graph 9 - 1: OECD commercial oil stocks



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

OECD **commercial crude stocks** rose m-o-m in May by 1.1 mb to stand at 1,466 mb. This is 128.0 mb lower than the same time a year ago and 60.8 mb below the latest five-year average. Compared with the previous month, OECD Asia Pacific and OECD Europe registered stock builds of 9.0 mb and 2.6 mb, respectively, while OECD America saw a stock draw of 10.5 mb.

Total product inventories also rose by 7.2 mb m-o-m in May to stand at 1,468 mb. This is 148.9 mb less than the same time a year ago, and 25.9 mb below the latest five-year average. Within the OECD regions, product stocks in OECD Europe fell by 1.8 mb, while OECD Americas and OECD Pacific rose by 4.0 mb and 5.1 mb, m-o-m, respectively.

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

OECD stocks	May 20	Mar 21	Apr 21	May 21	*Change May 21/Apr 21*
Crude oil	1,594	1,466	1,465	1,466	*1.1*
Products	1,617	1,460	1,461	1,468	*7.2*
Total	**3,211**	**2,926**	**2,926**	**2,934**	***8.3***
Days of forward cover	**77.7**	**65.7**	**65.0**	**64.2**	***-0.8***

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 0.8 days in May to stand at 64.2 days. This is 13.4 days below May 2020 levels, and 0.8 days below the latest five-year average. OECD Americas and OECD Asia Pacific were below the latest five-year averages: the Americas by 1.7 days at 62.0 days and Asia Pacific by 3.3 days at 51.9 days. OECD Europe, however, showed a surplus of 2.3 days at 74.9 days.

OECD Americas

OECD Americas total commercial stocks fell m-o-m by 6.5 mb in May to settle at 1,553 mb. This is 137.8 mb less than the same month last year and 38.3 mb lower than the latest five-year average.

Commercial crude oil stocks in OECD Americas fell m-o-m by 10.5 mb in May to stand at 831 mb, which is 47.6 mb lower than in May 2020, and 7.8 mb less than the latest five-year average. The stock draw came on the back of higher crude runs in May.

In contrast, **total product stocks** in OECD Americas rose m-o-m by 4.0 mb in May to stand at 722 mb. This was 90.3 mb lower than the same month one year ago and 30.5 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 rose m-o-m by 0.7 mb in May to settle at 1,010 mb. This is 105.7 mb less than the same month last year, and 10.4 mb below the latest five-year average.

OECD Europe's **commercial crude stocks** in May rose m-o-m by 2.6 mb to end the month at 437 mb, which is 44.7 mb lower than one year ago and 11.3 mb below the latest five-year average. The increase in crude oil inventories was due to lower m-o-m refinery throughputs in the EU-14 plus UK and Norway, which decreased by 140 tb/d to 8.77 mb/d.

In contrast, OECD Europe's **commercial product stocks** fell m-o-m by 1.8 mb to end May at 573 mb. This is 61.0 mb lower than a year ago, and 0.9 mb above the latest five-year average.

OECD Asia Pacific

OECD Asia Pacific's total commercial oil stocks rose m-o-m by 14.1 mb in May to stand at 372 mb. This is 33.4 mb lower than a year ago, and 37.9 mb below the latest five-year average.

OECD Asia Pacific's **crude inventories** rose by 9.0 mb m-o-m to end May at 198 mb, which is 35.8 mb lower than one year ago, and 41.7 mb below the latest five-year average.

OECD Asia Pacific's **total product inventories** also rose by 5.1 mb m-o-m to end May at 174 mb. This is 2.4 mb higher than the same time a year ago, and 3.8 mb above the latest five-year average.

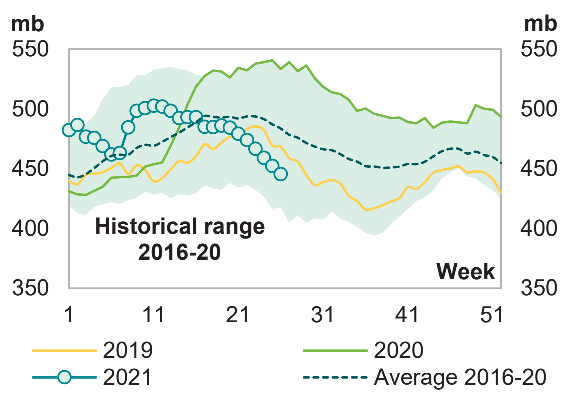
US

Preliminary data for June showed that **total US commercial oil stocks** rose slightly m-o-m by 0.4 mb to stand at 1,278 mb. This is 174.6 mb, or 12.0%, lower than the same month a year ago, and 50.3 mb, or 3.8%, below the latest five-year average. Crude stocks fell by 26.9 mb, while product stocks rose by 27.4 mb, m-o-m.

US **commercial crude stocks** in June fell m-o-m by 26.9 mb to stand at 452.3 mb. This is 79.6 mb, or 15.0%, lower than the same month last year, and 30.2 mb, or 6.3%, below the latest five-year average. The stock draw came on the back of higher crude runs.

In contrast, **total product stocks** in June rose m-o-m by 27.4 mb to stand at 825.9 mb. This is 95.0 mb, or 10.3%, below June 2020 levels, and 20.1 mb, or 2.4%, lower than the latest five-year average. The build was mainly driven by higher refinery output.

Graph 9 - 2: US weekly commercial crude oil inventories



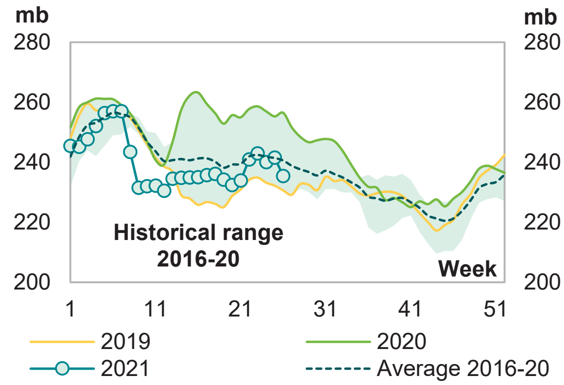
Sources: EIA and OPEC.

Gasoline stocks in June rose m-o-m by 7.6 mb to settle at 241.6 mb. This is 11.7 mb, or 4.6%, below the same month last year, but 0.6 mb, or 0.2%, higher than the latest five-year average. The monthly stock build came mainly on the back of higher gasoline output, which outpaced the increase in gasoline demand.

Distillate stocks also rose m-o-m by 4.3 mb in June to stand at 137.1 mb. This is 38.4 mb, or 21.9%, lower than a year ago, and 8.7 mb, or 6.0%, lower than the latest five-year average. The build in distillate stocks can be attributed to higher distillate production.

Jet fuel rose m-o-m by 2.4 mb, ending June at 44.7 mb. This is 3.2 mb, or 7.7%, higher than the same month last year, and 3.8 mb, or 9.2%, above the latest five-year average.

Graph 9 - 3: US weekly gasoline inventories



Sources: EIA and OPEC.

In contrast, **residual fuel oil stocks** fell m-o-m in June, decreasing by 1.6 mb. At 31.1 mb, this was 8.5 mb, or 21.5%, lower than a year ago, and 3.6 mb, or 10.5%, below the latest five-year average.

Table 9 - 2: US commercial petroleum stocks, mb

US stocks	Jun 20	Apr 21	May 21	Jun 21	Change Jun 21/May 21
Crude oil	**531.9**	**489.7**	**479.3**	**452.3**	***-26.9***
Gasoline	253.3	238.4	234.0	241.6	*7.6*
Distillate fuel	175.4	136.0	132.8	137.1	*4.3*
Residual fuel oil	39.6	31.3	32.7	31.1	*-1.6*
Jet fuel	41.5	40.5	42.3	44.7	*2.4*
Total products	**920.9**	**799.6**	**798.6**	**825.9**	***27.4***
Total	**1,452.8**	**1,289.4**	**1,277.8**	**1,278.3**	***0.4***
SPR	**656.0**	**633.4**	**627.8**	**622.5**	***-5.3***

Sources: EIA and OPEC.

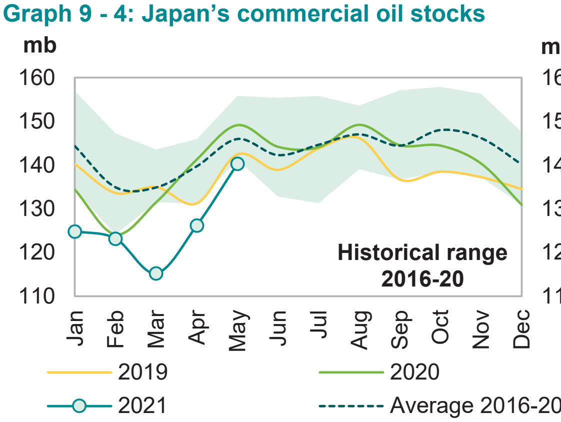
Japan

In **Japan**, **total commercial oil stocks** in May rose m-o-m by 14.1 mb to settle at 140.3 mb. This is 8.8 mb, or 5.9%, lower than the same month last year, and 5.7 mb, or 3.9%, below the latest five-year average. Crude and products stocks rose m-o-m by 9.0 mb and 5.1 mb, respectively.

Japanese **commercial crude oil stocks** rose in May to stand at 75.6 mb. This is 12.8 mb, or 14.5%, below the same month a year ago, and 10.6 mb, or 12.3%, lower than the latest five-year average. The build came on the back of lower crude throughput.

Japan's **total product inventories** rose m-o-m by 5.1 mb to end May at 64.7 mb. This is 4.0 mb, or 6.6%, higher than the same month last year, and 5.0 mb, or 8.3%, above the latest five-year average.

Graph 9 - 4: Japan's commercial oil stocks



Sources: METI and OPEC.

Gasoline stocks rose m-o-m by 1.9 mb to stand at 14.9 mb. This was 2.3 mb, or 18.3%, higher than a year ago, and 3.5 mb, or 30.9%, above the latest five-year average. Lower domestic gasoline sales, which fell by 4.6%, were behind the build in gasoline stocks.

Distillate stocks rose by 2.9 mb m-o-m to end May at 27.5 mb. This is 1.4 mb, or 5.6%, higher than the same month a year ago, and 2.4 mb, or 9.7%, above the latest five-year average. Within distillate components, both **kerosene and gasoil stocks** rose each m-o-m by 16.2%, while jet fuel stocks were down by 5.3%.

Total residual fuel oil stocks rose m-o-m by 0.6 mb in May to stand at 12.8 mb. This is 0.3 mb, or 2.7% higher than the same month last year, but 0.4 mb, or 3.2%, below the latest five-year average. Within components, fuel oil A and fuel oil B.C stocks rose by 3.4% and 5.2%, respectively.

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

Japan's stocks	May 20	Mar 21	Apr 21	May 21	*Change May 21/Apr 21*
Crude oil	**88.4**	**60.0**	**66.6**	**75.6**	***9.0***
Gasoline	12.6	12.5	13.0	14.9	*1.9*
Naphtha	9.6	8.6	9.8	9.5	*-0.3*
Middle distillates	26.0	23.0	24.6	27.5	*2.9*
Residual fuel oil	12.4	11.3	12.2	12.8	*0.6*
Total products	**60.7**	**55.3**	**59.6**	**64.7**	***5.1***
Total**	**149.1**	**115.2**	**126.2**	**140.3**	***14.1***

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

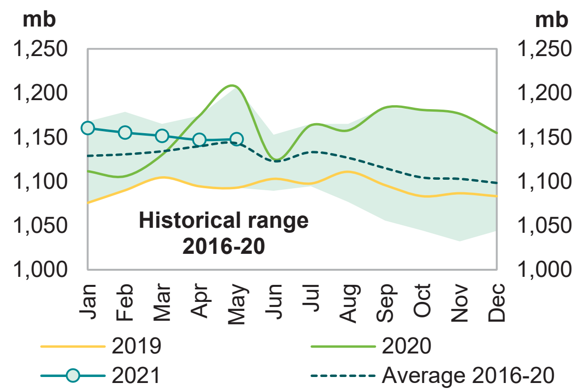
Sources: METI and OPEC.

EU-14 plus UK and Norway

Preliminary data for May showed that **total European commercial oil stocks** rose slightly m-o-m by 0.7 mb to stand at 1,148 mb. At this level, they were 59.6 mb, or 4.9%, below the same month a year ago, but 4.4 mb, or 0.4%, higher than the latest five-year average. Crude stocks went up by 2.6 mb, while total product stocks fell by 1.8 mb, m-o-m.

European **crude inventories** rose in May to stand at 473.6 mb. This is 43.8 mb, or 8.5% lower than the same month a year ago, and 24.8 mb, or 5.0%, lower the latest five-year average. The increase in crude oil inventories was due to lower m-o-m refinery throughputs in the EU-14 plus UK and Norway, which decreased by 140 tb/d to 8.77 mb/d.

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



Sources: Argus, Euroilstock and OPEC.

In contrast**, total European product stocks** fell m-o-m by 1.8 mb to end May at 674.0 mb. This is 15.8 mb, or 2.3%, lower than the same month a year ago, but 29.2 mb, or 4.5%, above the latest five-year average.

Gasoline stocks fell m-o-m by 1.3 mb in May to stand at 116.9 mb. This is 5.7 mb, or 4.7%, lower than the level registered the same time a year ago, but 1.0 mb/d, or 0.9%, higher than the latest five-year average.

Distillate stocks also fell m-o-m by 0.1 mb in May to stand at 456.9 mb. This is in line with the same month last year, and 26.7 mb, or 6.2%, above the latest five-year average.

Residual fuel stocks fell m-o-m by 1.1 mb in May to 68.7 mb. This is 6.3 mb, or 8.4%, lower than the same month one year ago, and 1.7 mb, or 2.4%, below the latest five-year average.

In contrast, **naphtha stocks** rose by 0.6 mb m-o-m in May, ending the month at 31.5 mb. This is 3.5 mb, or 10.1%, below May 2020 levels, but 3.2 mb, or 11.2%, higher than the latest five-year average.

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

EU stocks	May 20	Mar 21	Apr 21	May 21	*Change May 21/Apr 21*
Crude oil	**517.4**	**480.4**	**471.1**	**473.6**	***2.6***
Gasoline	122.6	120.0	118.2	116.9	*-1.3*
Naphtha	35.0	31.2	30.9	31.5	*0.6*
Middle distillates	457.1	454.3	457.0	456.9	*-0.1*
Fuel oils	75.0	65.5	69.8	68.7	*-1.1*
Total products	**689.8**	**671.1**	**675.8**	**674.0**	***-1.8***
Total	**1,207.2**	**1,151.5**	**1,146.9**	**1,147.6**	***0.7***

Sources: Argus, Euroilstock and OPEC.

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

Singapore

In May, **total product stocks in Singapore** fell m-o-m by 0.8 mb at 49.9 mb. This is 5.6 mb, or 10.2%, lower than the same month a year ago.

Light distillate stocks rose m-o-m by 1.1 mb in May to stand at 13.3 mb. This is 1.8 mb, or 12.0%, lower than the same month one year ago.

In contrast, **middle distillate stocks** fell by 1.4 mb in May to stand at 11.7 mb. This is 3.0 mb, or 20.4%, lower than a year ago.

Residual fuel oil stocks also fell by 0.5 mb, ending May at 24.8 mb, which is 0.8 mb, or 3.2%, lower than in May 2020.

ARA

Total product stocks in ARA fell for the third consecutive month in May and were down by 0.1 mb to 46.8 mb. This is 7.6 mb, or 13.9%, lower than the same month a year ago.

Gasoline stocks in May fell m-o-m by 0.1 mb to stand 10.1 mb, which is 1.4 mb, or 12.4%, lower than the same month one year ago.

Residual fuel stocks also fell m-o-m by 1.4 mb to end May at 8.4 mb. This is 2.6 mb, or 23.6%, less than the level registered one year ago.

In contrast, **gasoil stocks** rose m-o-m by 0.7 mb in May to stand at 16.9 mb, which is 3.1 mb, or 15.4%, lower than in May 2020.

Jet oil stocks rose m-o-m by 1.4 mb to end May at 9.1 mb. This is 2.1 mb, or 29.5%, above the level seen one year ago.

Fujairah

During the week ending 28 June 2021, **total oil product stocks in Fujairah** rose by 0.44 mb w-o-w to stand at 23.06 mb, according to data from Fed Com and S&P Global Platts. At this level, total oil stocks were 5.43 mb lower than the same time a year ago. While light distillates witnessed a stock build w-o-w, middle and heavy distillate stocks showed a stock draw.

Light distillate stocks rose by 1.83 mb w-o-w to stand at 7.26 mb, which is 0.66 lower than the same period a year ago. In contrast, **middle distillate stocks** fell by 0.31 mb to stand at 3.94 mb, which is 0.16 mb lower than a year ago. **Heavy distillate stocks** also fell by 1.08 mb to stand at 11.86 mb, which is 4.61 mb lower than the same time last year.

Balance of Supply and Demand

Demand for OPEC crude in 2021 remained unchanged from the previous month at 27.7 mb/d, around 5.0 mb/d higher than the 2020 level. According to secondary sources, OPEC crude production averaged 25.1 mb/d in 1Q21, about 0.2 mb/d lower than demand for OPEC crude in the same period. In the 2Q21, OPEC crude production averaged 25.5 mb/d, 1.6 mb/d lower than demand.

Based on the first world oil demand and non-OPEC supply forecast in 2022, demand for OPEC crude is expected to reach 28.7 mb/d, 1.1 mb/d higher than the 2021 level.

Balance of supply and demand in 2021

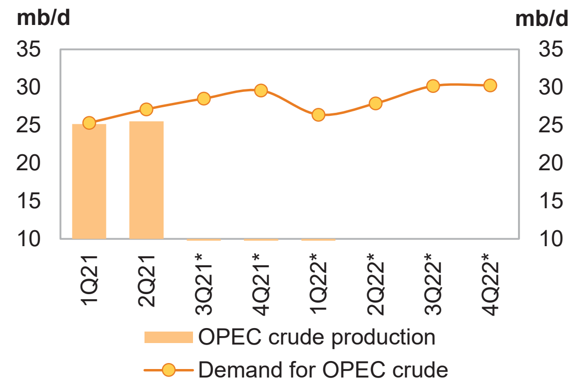
Demand for OPEC crude in 2021 remained unchanged from the previous month at 27.7 mb/d, around 5.0 mb/d higher than in 2020.

Both 1Q21 and 3Q21 were revised down by 0.1 mb/d, while 4Q21 was revised up by 0.2 mb/d, compared to the previous assessment. 2Q21 remained unchanged.

When compared with the same quarters in 2020, demand for OPEC crude in 1Q21 and 2Q21 is estimated to be 3.8 mb/d and 10.1 mb/d higher, respectively. 3Q21 and 4Q21 are expected to see a rise of 3.6 mb/d and 2.5 mb/d, respectively, compared with the same quarters a year earlier.

According to secondary sources, OPEC crude production averaged 25.1 mb/d in 1Q21, about 0.2 mb/d lower than demand for OPEC crude in the same period. In the 2Q21, OPEC crude production averaged 25.5 mb/d, 1.6 mb/d lower than demand.

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



*Note: * 3Q21-4Q22 = 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	**90.62**	**92.80**	**95.32**	**98.24**	**99.82**	**96.58**	***5.95***
Non-OPEC liquids production	62.94	62.38	63.10	64.49	65.01	63.76	*0.81*
OPEC NGL and non-conventionals	5.05	5.11	5.11	5.22	5.23	5.17	*0.12*
(b) Total non-OPEC liquids production and OPEC NGLs	**67.99**	**67.49**	**68.21**	**69.71**	**70.24**	**68.92**	***0.93***
Difference (a-b)	**22.64**	**25.32**	**27.11**	**28.52**	**29.58**	**27.65**	***5.02***
OPEC crude oil production	**25.64**	**25.15**	**25.52**				
Balance	**3.01**	**-0.17**	**-1.58**				

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

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Oil Market Report - July 2021

Flagship report — July 2021

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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

- Following two consecutive months of decline, global oil demand surged by an estimated 3.2 mb/d to 96.8 mb/d in June. Robust global economic growth, rising vaccination rates and easing social distancing measures will combine to underpin stronger global oil demand for the remainder of the year. Global oil demand is expected to increase by 5.4 mb/d in 2021 and 3.0 mb/d in 2022, although escalating Covid cases in a number of countries remain a key downside risk to the forecast.
- World oil supply rose by 1.1 mb/d in June to 95.6 mb/d as OPEC+ eased output cuts and producers outside the alliance ramped up after maintenance. The call on OPEC+ crude oil is set to reach 42.8 mb/d in 3Q21 and 44.1 mb/d in 4Q21, compared with June production of 40.9 mb/d. Non-OPEC countries not part of the pact will boost output by 770 kb/d in 2021 and 1.6 mb/d in 2022.
- Global refining throughput increased by 1.6 mb/d in June after stagnating in May. Runs are expected to increase by another 2.7 mb/d over July and August before a seasonal slowdown in 4Q21. The sharp increase in June was partly behind higher crude oil prices in the month that negatively affected product cracks and refinery margins.
- OECD total industry stocks rose by 18.1 mb in May and stood at 2 945 mb, 75.8 mb below the 2016-2020 average and10.8 mb below the pre-Covid 2015-19 average. Preliminary June data for the US, Europe and Japan show that industry stocks fell by a combined 21.8 mb. Crude oil held in short-term floating storage declined by 23.7 mb to 83.3 mb in June, its lowest since February 2020.
- Crude prices rose in June on bullish oil fundamentals and financial markets. Backwardation steepened on crude futures contracts reflecting tighter markets and falling oil stocks versus demand. North Sea Dated rose $4.41/bbl in June to $72.96/bbl and peaked at $77.70/bbl on 5 July following a deadlock in OPEC+ negotiations to ease supply restrictions from August.

On edge

World oil markets are on edge with OPEC+ negotiations to boost supply now in deadlock. After initially surging to multi-year highs in early July, benchmark crude oil prices have since eased. At the time of writing, Brent was around $75/bbl. Oil prices reacted sharply to the OPEC+ impasse last week, eyeing the prospect of a deepening supply deficit if a deal cannot be reached. At the same time, the possibility of a market share battle, even if remote, is hanging over markets, as is the potential for high fuel prices to stoke inflation and damage a fragile economic recovery. The uncertainty over the potential global impact of the Covid-19 Delta variant in the coming months is also tempering sentiment.

Most OPEC+ delegates tentatively agreed to raise output by around 400 kb/d per month from August until the remaining 5.8 mb/d supply cuts are unwound, effectively extending the deal to the end of 2022. While the UAE supported part of the proposal to raise production, it objected to an extension beyond April, when the current deal expires, and insisted on a higher baseline from which cuts are calculated to better reflect its increased capacity.

The OPEC+ stalemate means that until a compromise can be reached, production quotas will remain at July's levels. In that case, oil markets will tighten significantly as demand rebounds from last year's Covid-induced plunge. The overhang in global oil stocks that built up last year has already been worked off, with OECD industry stocks now well below historical averages.

Crude oil balances are expected to be especially tight. Refiners are ramping up quickly to meet higher demand. Our current balances suggest 3Q21 could see the largest crude oil stock draw in at least a decade. Product stocks are also set to fall as drivers frustrated by confinement and travel restrictions take to the road en masse. Mobility data show US travel in recent weeks far exceeding pre-Covid levels. Our forecast for global oil demand is largely unchanged since last month's Report, rising 5.4 mb/d this year and a further 3 mb/d in 2022.

While prices at these levels could increase the pace of electrification of the transport sector and help accelerate energy transitions, they could also put a drag on the economic recovery, particularly in emerging and developing countries. In June, US retail gasoline prices rose above $3/gal for the first time in nearly seven years. Pump prices have also risen sharply in Europe. In India, gasoline and diesel prices are at their highest level ever, adding to inflationary pressures amid a broader commodities rally. Fuel prices are rising in Brazil, too, amid its steepest consumer price inflation rate in nearly five years.

Oil markets are likely to remain volatile until there is clarity on OPEC+ production policy. And volatility does not help ensure orderly and secure energy transitions – nor is it in the interest of either producers or consumers.

IEA World Oil Supply and Demand Forecasts: Summary (Table)
2021-07-13 08:00:00.3 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	100.6	100.3	98.7	98.2	99.4	98.1	94.7	93.6	99.5	96.4
Total OECD	46.2	46.6	45.7	45.3	46.5	46.0	43.9	42.3	45.9	44.7
Americas	25.3	25.6	25.1	24.5	25.3	25.3	24.3	22.8	25.1	24.4
Europe	13.2	13.7	13.4	13.0	13.5	13.5	12.6	11.9	13.3	12.9
Asia Oceania	7.7	7.3	7.2	7.8	7.7	7.2	7.0	7.6	7.5	7.4
Non-OECD countries	54.4	53.7	53.0	52.9	52.9	52.0	50.8	51.3	53.5	51.8
FSU	5.1	5.0	4.6	4.8	5.0	4.9	4.6	4.6	4.9	4.8
Europe	0.8	0.8	0.7	0.7	0.8	0.7	0.7	0.7	0.7	0.7
China	15.8	15.6	15.7	15.3	15.3	15.1	15.1	14.7	15.6	15.1
Other Asia	14.3	13.7	14.1	14.2	13.9	13.0	12.9	13.6	14.1	13.3
Americas	6.2	6.3	5.9	5.9	6.0	6.0	5.8	5.8	6.1	5.9
Middle East	8.1	8.4	7.9	8.0	7.9	8.4	7.8	7.7	8.1	7.9
Africa	4.1	4.0	4.0	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	n/a	94.5	92.4	n/a	n/a
Non-OPEC	66.2	66.2	65.5	64.8	65.0	65.0	63.7	61.9	65.7	63.9
Total OECD	29.9	29.6	29.2	29.2	29.0	28.6	27.9	27.4	29.5	28.2
Americas	25.7	25.5	25.2	24.9	24.7	24.5	24.1	23.3	25.3	24.2
Europe	3.6	3.5	3.5	3.7	3.7	3.5	3.2	3.6	3.6	3.5
Asia Oceania	0.5	0.5	0.6	0.6	0.6	0.6	0.5	0.5	0.5	0.5
Non-OECD	30.8	30.8	30.8	30.8	30.8	30.8	30.6	30.3	30.8	30.6
FSU	13.7	13.7	13.7	13.7	13.7	13.7	13.7	13.4	13.7	13.6
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	2.9	2.9	2.9	2.9	3.0	3.0	2.9	3.0	2.9	3.0
Americas	5.7	5.6	5.5	5.5	5.6	5.5	5.3	5.3	5.6	5.4
Middle East	3.2	3.2	3.2	3.2	3.2	3.2	3.2	3.1	3.2	3.2
Africa	1.2	1.2	1.2	1.2	1.3	1.2	1.3	1.3	1.2	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	n/a	30.8	30.4	n/a	n/a
Crude	n/a	n/a	n/a	n/a	n/a	n/a	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 *	28.9	28.6	27.6	27.9	29.0	27.7	25.7	26.5	28.3	27.2

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/QW67PZT0AFB9

IEA: June Crude Oil Production in OPEC Countries (Table)
2021-07-13 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:

	June 2021	May 2021	June MoM
Total OPEC	25.93	25.48	0.45
Total OPEC10	21.76	21.38	0.38
Algeria	0.91	0.89	0.02
Angola	1.08	1.12	-0.04
Congo	0.28	0.27	0.01
Equatorial Guinea	0.11	0.11	0.00
Gabon	0.19	0.17	0.02
Iraq	3.90	3.94	-0.04
Kuwait	2.38	2.36	0.02
Nigeria	1.31	1.34	-0.03
Saudi Arabia	8.92	8.54	0.38
UAE	2.68	2.64	0.04
Iran	2.45	2.40	0.05
Libya	1.17	1.15	0.02
Venezuela	0.55	0.55	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/QW67PZT0AFBD

IEA REPORT WRAP: OPEC+ Supply Concern; Demand Forecasts Steady
2021-07-13 08:27:52.22 GMT

By Stephen Voss
(Bloomberg) -- Summary including stories from IEA's monthly
Oil Market Report on Tuesday:
* IEA warns of much tighter oil market unless OPEC+ boosts
supply
** Only minor adjustments to world demand estimates
** 2H demand on course to exceed 1H by 4.6m b/d
** 2021 demand kept little changed at 96.4m b/d
** World oil demand to exceed 100m b/d in 3Q22
** Click here for summary of key IEA supply/demand forecasts
* Possibilities exist for either:
** Market share battle within OPEC+

** High prices fueling inflation
* Saudi oil-supply boost drove up OPEC output in June: IEA
** See full table of June production; total OPEC +450k b/d m/m
* Compliance with pledged cutbacks in June:
** OPEC 123%; non-OPEC 97%; combined OPEC+ 114%
** Saudi Arabia 126%, Russia 96%
* Iran can quickly pump 3.8m b/d of oil if sanctions eased
* Russia's compliance with OPEC+ deal rose to 96% in June
* China will overtake Europe in crude processing in 2022
* Gasoline demand growth to outpace diesel, jet fuel in 3Q
* Canada drives non-OPEC+ output growth; Covid hampers Brazil
* U.S. oil production to reach record high by end of 2022
* Brent-Dubai spread, backwardation pressure Atlantic's crude
* IEA Table: World supply/demand forecasts by quarter
* NOTE: OPEC's own monthly report will be issued Thursday. OPEC+ talks broke down last week, derailing plans to continue gradually raising production. Prior to the breakdown, the 23-nation group was discussing monthly output increases of 400,000 b/d

--With assistance from Amanda Jordan, Jack Wittels, Rachel Graham, Grant Smith, Julian Lee, Olga Tanas, Bill Lehane and Kristian Siedenburg.

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
Christopher Sell

To view this story in Bloomberg click here:
https://blinks.bloomberg.com/news/stories/QW696KT1UM11

IEA Warns of Much Tighter Oil Market Unless OPEC+ Boosts Supply
2021-07-13 08:00:00.18 GMT

By Grant Smith
(Bloomberg) -- Global oil markets are set to "tighten significantly" unless the OPEC+ alliance resolves its standoff and agrees to increase production, the International Energy Agency warned.
Deadlocked by a dispute between Saudi Arabia and the United Arab Emirates, OPEC+ is set to keep output levels unchanged next month even as fuel consumption bounces back from the pandemic and summer driving demand peaks.
The group's impasse threatens to inflict a "deepening supply deficit," with "the potential for high fuel prices to

stoke inflation and damage a fragile economic recovery," the IEA said in its monthly report. Brent crude is trading close to a two-year high above $75 a barrel.
The Organization of Petroleum Exporting Countries and its partners had been gradually restoring the vast quantities of oil production they shuttered during the pandemic, but the spat between the two Middle East nations -- centered around the output quota of the UAE -- is holding up the process.
Their standoff comes at a particularly inopportune moment, the IEA report shows. The oil inventory glut that amassed during the pandemic has cleared, and stocks are now below average levels. Meanwhile, world demand is set to rebound by a vigorous 5.4 million barrels a day this year from the unprecedented slump seen in 2020.
"Robust global economic growth, rising vaccination rates and easing social distancing measures will combine to underpin stronger global oil demand for the remainder of the year," said the Paris-based agency, which advises most major economies.

In Limbo

OPEC+ was on the cusp of approving a plan to revive output in monthly installments of 400,000 barrels a day through to late 2022. The group's talks broke down on July 5 after a third attempt to find an agreement, and despite mediation efforts the deal remains in limbo.
With August sales fixed and most Gulf countries preparing for an Islamic holiday, the discussion will have shifted to September supply volumes by the time the coalition reconvenes, delegates said.
Even if OPEC+ clinches an accord, the IEA report shows that the 400,000 barrel-a-day output hike under consideration will fall far short of consumers' needs.
The 23-nation group pumped 40.9 million barrels a day in June, the IEA estimates. Even if OPEC+ proceeds with increases planned for this month, its output will still be significantly below the 43.45 million a day that the IEA projects will be required from the cartel in the second half of the year.
That could cause inventories to dwindle further. Oil stockpiles in developed nations are already 10.8 million barrels below the average level of 2015 to 2019, the agency said. They had been roughly 250 million barrels above average at the peak of the glut last summer.
Prices have remained volatile since the OPEC+ clash as traders grapple with an alternative outcome, in which the group descends into another price war like the one seen in early 2020.
"The possibility of a market share battle, even if remote, is hanging over markets," the agency said. Whatever the eventual result, the volatility buffeting markets in the meantime isn't

“in the interest of either producers or consumers,” it warned.

To contact the reporter on this story:
Grant Smith in London at gsmith52@bloomberg.net
To contact the editor responsible for this story:
James Herron at jherron9@bloomberg.net

To view this story in Bloomberg click here:
https://blinks.bloomberg.com/news/stories/QW65AZT0G1L0

IEA World Oil Supply/Demand Key Forecasts
2021-07-13 08:00:00.4 GMT

By Kristian Siedenburg
(Bloomberg) -- World oil demand 2022 fcast was unrevised at 99.5m b/d in Paris-based Intl Energy Agency’s latest monthly report.
* 2021 world demand was unrevised at 96.4m b/d
* Demand change in 2022 est. 3.1% y/y or 3m b/d
* Non-OPEC supply 2022 was unrevised at 65.7m b/d
* Call on OPEC crude 2022 was unrevised at 28.3m b/d
* Call on OPEC crude 2021 was unrevised at 27.2m b/d
** OPEC crude production in June rose by 450k b/d on the month to 25.9m b/d
* Detailed table: FIFW NSN QW67PZT0AFB9 <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/QW67R3T1UM11

Saudi Oil-Supply Boost Drove Up OPEC Output in June, IEA Says
2021-07-13 08:00:00.7 GMT

By Amanda Jordan
(Bloomberg) -- OPEC’s June crude production rose 450k b/d from May to 25.93m b/d as Saudi Arabia led the return of barrels to the market, the IEA said in its monthly report.
* Saudi Arabia pumped 8.92m b/d, up 380k b/d from a month earlier, as it continued to unwind its voluntary cuts
** Riyadh could raise July output by 580k b/d as per the OPEC+

agreement and as it phases out its remaining voluntary curbs
* Kuwaiti crude supply inched up to 2.38m b/d, while UAE production climbed 40k b/d to 2.68m b/d, just below its higher OPEC+ target
* Iraq was the only Mideast producer to reduce output, pumping 3.9m b/d -- down 40k b/d from May and 50k b/d below its OPEC+ cap
* Supply from Iran -- exempt from quotas -- advanced 50k b/d to 2.45m b/d
* Among African countries, Nigeria's production slipped 30k b/d to 1.31m b/d, with operational issues, sabotage and pipeline leaks keeping output below its quota
* Angolan supply dropped to 1.08m b/d, 220k b/d below its target
* Libyan production edged up to 1.17m b/d
* OPEC's compliance with quotas was 123% over the month

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
Alaric Nightingale

To view this story in Bloomberg click here:
https://blinks.bloomberg.com/news/stories/QW66VXT1UM0X

Iran Can Quickly Pump 3.8m b/d of Oil If Sanctions Eased: IEA
2021-07-13 08:00:00.5 GMT

By Rachel Graham
(Bloomberg) -- Iran's oil output could quickly increase to 3.8m b/d if sanctions are eased, the IEA said in its monthly oil market report.
* Nation has about 59 million barrels of crude and condensate stored on tankers and it will seek to shift that overhang as quickly as possible
* NOTE: Iran's crude output was 2.49m b/d in June, according to Bloomberg estimates; the IEA's crude-only figure for last month was 2.45m b/d

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/QW676DT0AFB6

Russia's Compliance With OPEC+ Deal Rose to 96% in June: IEA
2021-07-13 08:00:00.32 GMT

By Olga Tanas
(Bloomberg) -- Russia's compliance with OPEC+ agreement in June increased to 96% from 94% in May, the IEA said in its monthly report.
* Planned maintenance led to a 10k b/d drop in crude-only output from May level to 9.52k b/d in June, which is still 70k b/d above nation's target for the month
** NOTE: Russia's crude-only output quota for June under OPEC+ deal is 9.457m b/d. Last month Russian oil producers pumped around 10.419m b/d of crude oil and condensate, according to preliminary data from the Energy Ministry's CDU-TEK unit, which doesn't provide a breakdown between the two types of oil
** Increases from Rosneft and its unit Bashneft, Lukoil and Gazprom Neft were offset by lower production from Tatneft, Slavneft and Sakhalin-1.
* Based on June crude oil production estimates, Russia is withholding 8% of its crude from the market compared with 30% withheld by UAE, 27% by Saudi Arabia, 21% by Iraq and 19% by Kuwait
* Russia's sustainable capacity -- the level that can be reached within 90 days and sustained for an extended period -- is estimated at 10.40m b/d
** Russia's spare capacity versus June is estimated at 0.88m b/d
* READ: (June 30) Russia Able to Boost Oil Production Quickly If OPEC+ Agrees

To contact the reporter on this story:
Olga Tanas in Moscow at otanas@bloomberg.net
To contact the editors responsible for this story:
James Herron at jherron9@bloomberg.net
Christopher Sell

To view this story in Bloomberg click here:
https://blinks.bloomberg.com/news/stories/QW66VST0AFB4

China Will Overtake Europe in Crude Processing in 2022, IEA Says
2021-07-13 08:00:00.8 GMT

By Rachel Graham
(Bloomberg) -- East of Suez crude throughput will rise to a record in 2022 and China will overtake Europe in the amount it processes, the IEA said in its monthly oil market report.
* "After reaching parity in 2019, China's lead is forecast to widen to 3m b/d in 2022 as European activity is not expected to

recover to pre-pandemic levels"
** East of Suez throughput forecast at almost 39m b/d next year
** In Asia, countries with capacity additions such as Brunei and Malaysia will see throughput surpassing pre-pandemic levels next year, while others will take longer to recover fully
** The Middle East and Latin America are on track to surpass 2018 levels in 2022
* For this year, the IEA sees increased throughput globally through August, before declining in September and October due to maintenance
** It expects crude runs to increase to 80.4m b/d in August, about 500k b/d higher than July

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
Fred Pals

To view this story in Bloomberg click here:
https://blinks.bloomberg.com/news/stories/QW67NTT1UM11

Gasoline Demand Growth to Outpace Diesel, Jet Fuel in 3Q: IEA
2021-07-13 08:00:00.17 GMT

By Jack Wittels
(Bloomberg) -- Demand increases in gasoil/diesel and jet/kerosene are expected to be outpaced by gasoline this quarter, the IEA said in its monthly oil market report.
* Global gasoline demand forecast to rise by 1.1m b/d q/q in 3Q
** Jet/kerosene to increase by 830k b/d, gasoil/diesel by 760k b/d
* "While the Covid-19 Delta variant is spreading fast at the time of writing, high vaccination counts, notably amongst the elderly, and the relatively greater availability of vaccine jabs in the OECD have given governments enough confidence to reopen most activities"
** "Nonetheless, Covid-19 remains a significant threat to oil demand growth in the near- to medium-term, in particular in the non-OECD"
* IEA expects global oil demand to rise by 3.3m b/d q/q in 3Q

To contact the reporter on this story:
Jack Wittels in London at jwittels1@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/QW694DT0AFB7

Canada Drives non-OPEC+ Output Growth; Covid Hampers Brazil: IEA
2021-07-13 08:00:00.36 GMT

By Julian Lee
(Bloomberg) -- Canada will be "the largest source of non-OPEC+ supply growth in 2021," while persistently high levels of new Covid-19 cases in Brazil "could hinder production growth expected later this year," the IEA said in its monthly report.
* Canadian production to rise by 350k b/d in 2021 after synthetic crude facilities come back from maintenance in 2Q21
** Syncrude production rebounded by 230k b/d from a 4-year low of 830k b/d in April
** Output will rise by a further 170k b/d in 2022 on higher bitumen production
** Forecast not affected by cancellation of 830k b/d Keystone XL pipeline, with adequate capacity to transport crude by rail and in other new pipelines
* In Brazil, "contrary to expectations, production has yet to make a strong rebound to levels seen in 3Q20"
** Unplanned outages are cutting activity, particularly in the Campos basin, and activity continues to suffer from Covid-19 disruptions
** June output around 3m b/d, 170k b/d below August 2020
** Production outlook has been downgraded, with growth cut to 50k b/d in 2021 and 150k b/d in 2022

To contact the reporter on this story:
Julian Lee in London at jlee1627@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/QW69XET0G1KW

U.S. Oil Production to Reach Record High by End of 2022: IEA
2021-07-13 08:00:00.35 GMT

By Julian Lee
(Bloomberg) -- Rising U.S. production as capital constraints ease should see output of crude, condensate and NGLs "brush up against record highs by end-2022," the IEA said in its

monthly report.
* U.S liquids production, including NGLs, to grow by 950k b/d next year, after no growth in 2021
* Gulf of Mexico production should reach record high above 2m b/d by end of 2022, adding 100k b/d
** 2 fields, Manuel and Praline, brought into production in June with combined liquids production of 20k b/d
** Bigger boost to come next year from start of 3 major projects -- Mad Dog 2, Vito, King's Quay -- with combined plateau production of 300k b/d
* U.S. light tight oil supplies to rise by 190k b/d over 2H21 with higher drilling by privately owned operators and faster completion of previously drilled wells
** Larger shale producers seem to be "sticking with budgets set when WTI was around $40/bbl"
** Capital discipline is expected to ease in 2022, allowing LTO supply to rise 620k b/d y/y, up from 120k b/d in 2021
* Alaska production to remain around 440k b/d, with new supply from GMT-2 project offsetting declines at Kuparuk, Alpine fields

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
Christopher Sell

To view this story in Bloomberg click here:
https://blinks.bloomberg.com/news/stories/QW680BT0AFB7

Brent-Dubai Spread, Backwardation Pressure Atlantic's Crude: IEA
2021-07-13 08:00:00.33 GMT

By Bill Lehane
(Bloomberg) -- The Brent-Dubai premium and the strong ICE Brent backwardation continue to pressure East of Suez demand for Atlantic Basin crude grades, IEA says in report.
* "Nevertheless, Indian refiners bought Nigerian barrels as they boosted runs while Chinese refiners slowly picked-off Angolan barrels"
* West African crude differentials flipped from discounts to North Sea Dated to premiums last month on better buying from Europe, Asia
* Nigeria's Forcados averaged 59c/bbl premium to North Sea Dated, a jump of $1.08/bbl m/m;Bonny Light averaged 34c/bbl, a gain of $1.13/bbl
* Angola's Cabinda averaged 41c/bbl, a gain of 62c/bbl on the month

To contact the reporter on this story:
Bill Lehane in London at blehane@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/QW69IST1UM12

https://www.opec.org/opec_web/en/press_room/6512.htm

19th OPEC and non-OPEC Ministerial Meeting concludes

No 21/2021 Vienna, Austria 18 Jul 2021

The 19th OPEC and non-OPEC Ministerial Meeting (ONOMM), held via videoconference, concluded on Sunday 18 July 2021.

The Meeting noted the ongoing strengthening of market fundamentals, with oil demand showing clear signs of improvement and OECD stocks falling, as the economic recovery continued in most parts of the world with the help of accelerating vaccination programmes.

The Meeting welcomed the positive performance of Participating Countries in the Declaration of Cooperation (DoC). Overall conformity to the production adjustments was 113% in June (including Mexico), reinforcing the trend of high conformity by Participating Countries.

In view of current oil market fundamentals and the consensus on its outlook, the Meeting resolved to:

Reaffirm the Framework of the Declaration of Cooperation, signed on 10 December 2016 and further endorsed in subsequent meetings, including on 12 April 2020.

Extend the decision of the 10th OPEC and non-OPEC Ministerial Meeting (April 2020) until the 31st of December 2022.

Adjust upward their overall production by 0.4 mb/d on a monthly basis starting August 2021 until phasing out the 5.8 mb/d production adjustment, and in December 2021 assess market developments and Participating Countries' performance.

Continue to adhere to the mechanism to hold monthly OPEC and non-OPEC Ministerial Meetings for the entire duration of the Declaration of Cooperation, to assess market conditions and decide on production level adjustments for the following month, endeavoring to end production adjustments by the end of September 2022, subject to market conditions.

Adjust, effective 1st of May 2022, the baseline for the calculations of the production adjustments according to the attached table (table 1).

Reiterate the critical importance of adhering to full conformity and taking advantage of the extension of the compensation period until the end of September 2021. Compensation plans should be submitted in accordance with the statement of the 15th OPEC and non-OPEC Ministerial Meeting.

The meeting decided to hold the 20th OPEC and non-OPEC Ministerial Meeting on 1 September 2021.

https://www.opec.org/opec_web/static_files_project/media/downloads/Table%20-%20Reference%20production.pdf

	Reference Production up to end of April 2022	Reference Production effective May 2022
Algeria	1057	1057
Angola	1528	1528
Congo	325	325
Eq.Guinea	127	127
Gabon	187	187
Iraq	4653	4803
Kuwait	2809	2959
Nigeria	1829	1829
Saudi Arabia	11000	11500
UAE	3168	3500
Azerbaijan	718	718
Bahrain	205	205
Brunei	102	102
Kazakhstan	1709	1709
Malaysia	595	595
Mexico*	1753	1753
Oman	883	883
Russia	11000	11500
Sudan	75	75
South Sudan	130	130
OPEC 10	26683	27815
Non-OPEC	17170	17670
OPEC+	43853	45485

China’s Crude Imports to Rise to 10-10.3m B/d in 3Q: FGE
2021-07-15 05:32:46.634 GMT

By Saket Sundria
(Bloomberg) -- China’s crude imports may rise to 10m-10.3m b/d in 3Q but any significant upside will be limited due to high prices and a strong backwardation in the market structure, FGE said in a note.
* Imports were 9.8m b/d in June from a 5-month low of 9.6m in May, spurred by higher purchases from Rongsheng, which is preparing to fully commission the 400k b/d phase-2 of its refinery at Zhejiang
* There’s likely to be ~25m barrels drawn down from stockpiles over 3Q
** National oil companies drew down inventories in recent months, and may continue doing so as they ramp up runs over Aug.-Sept.
* Imports likely to rise above 10.5m b/d in 4Q
** 4Q imports will be driven by the start up of new refineries and need to replenish inventories after 5-6 months of drawdowns, although this will be offset by quota crunch faced by independent processors
** China’s total crude inventories will reach mid-2020 levels by end Sept. after ~100m barrels of drawdown over 2Q and 3Q
* Some independent refiners face uncertainty due to crackdown by government
** Several concluding maintenance over next few months; some returned to spot market to buy Aug.-Sept. delivery crude
** Most independents cautious in planning crude imports as they received lower quotas; some drawing from inventories to sustain runs
** Independents’ crude imports will fall by 600k b/d q/q in 4Q, with potential for further downside of ~200k b/d
* READ: Oil Refiners in China Log Another Record in Challenge to U.S.

To contact the reporter on this story:
Saket Sundria in Singapore at ssundria@bloomberg.net
To contact the editors responsible for this story:
Serene Cheong at scheong20@bloomberg.net
Andrew Janes

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https://www.reuters.com/article/india-oil/indias-june-oil-imports-hit-their-lowest-in-9-months-idUSL4N2OQ3PY

JULY 16, 20212:23 AMUPDATED AN HOUR AGO

India's June oil imports hit their lowest in 9 months

By Nidhi Verma 2 MIN READ

NEW DELHI (Reuters) - India's crude oil imports in June fell to their lowest in nine months, as refiners curtailed purchases amid higher fuel inventories due to low consumption and renewed coronavirus lockdowns in the previous two months.

FILE PHOTO: Oil tankers are seen parked at a yard outside a fuel depot on the outskirts of Kolkata February 3, 2015. REUTERS/Rupak De Chowdhuri/File Photo

India, the world's third-biggest oil importer and consumer, shipped in about 3.9 million barrels per day (bpd) of crude last month, about 7% down from May, but 22% higher from year-ago levels, tanker arrival data obtained from trade sources showed.

India is the second major importer in Asia, after China, to post a slump in last month's crude imports.

After an uptick in India's fuel demand in February and March, the country's refiners cranked up crude processing and oil imports, said an Indian refining official who declined to be named as he is not authorised to speak to media.

However, fuel demand fell sharply in April and May after the government imposed restrictions to curb a second wave of coronavirus, leaving refiners with high fuel inventories.

"We had enough inventory of refined fuel so there was little scope to raise crude imports," the source said, adding that the export market was unattractive as profits were low.

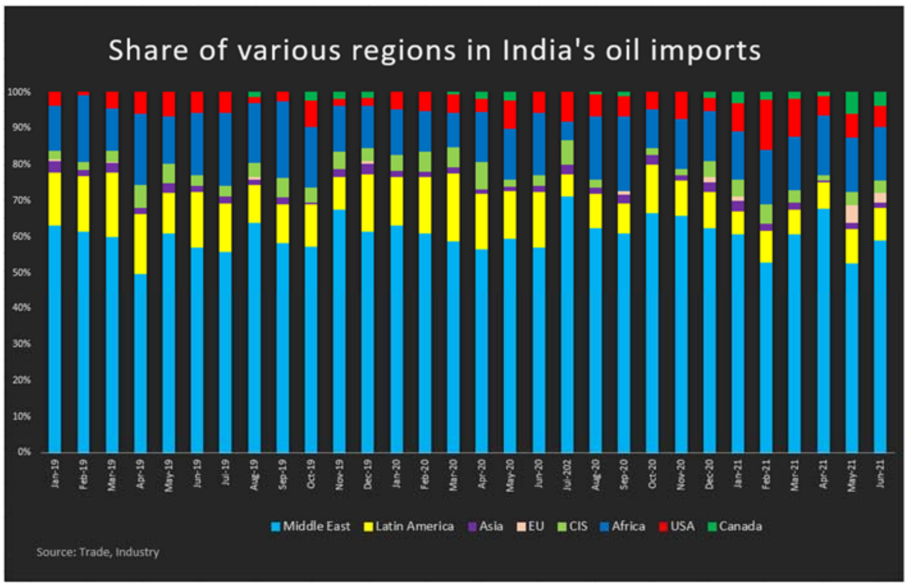
India's crude imports between April and June, however, rose 11.7% year-on-year to 4.1 million bpd as the lockdown curbs were not as severe as last year when COVID-19 first hit the nation, according to the data.

Last month, Iraq stayed as the top oil supplier to India, followed by Saudi Arabia. The United Arab Emirates climbed four notches to emerge as third-biggest supplier while Nigeria rose to No.4 from No.5 in May.

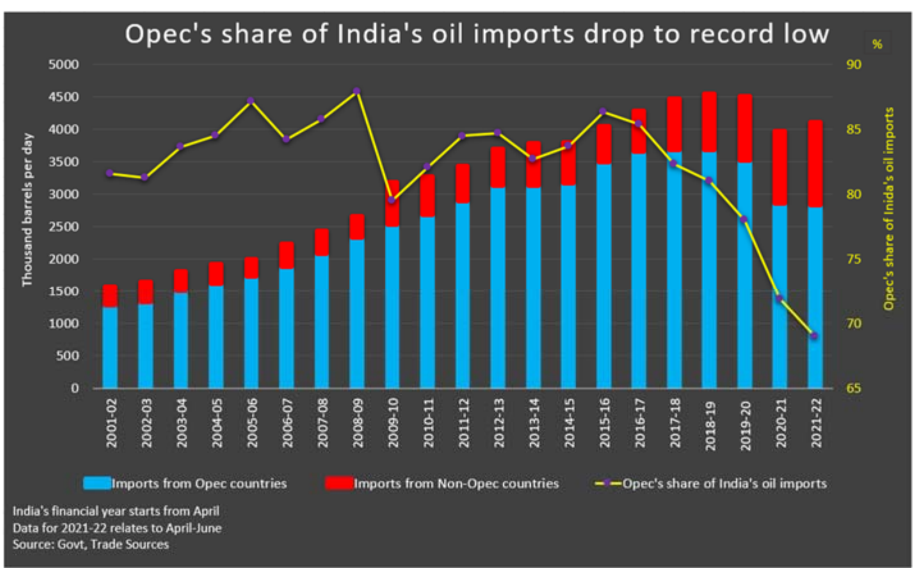
The United States was at No.5, followed by Canada.

The share of oil from the Middle East in India's imports rose to about 59% in June from 53% in the prior month, while that of other regions declined, data showed.

Graphic: Share of various regions in India's oil imports



Graphic: Opec's share of India's oil imports dropped to record low



Reporting by Nidhi Verma; Editing by Florence Tan and Sherry Jacob-Phillips

Our Standards: The Thomson Reuters Trust Principles.

Gasoline Swings Back to Growth in India as Covid Trauma Recedes
2021-07-16 08:18:53.586 GMT

By Debjit Chakraborty
(Bloomberg) -- Gasoline sales in India, the world's third-largest oil consumer, have bounced back to pre-virus levels for the first time since a brutal Covid-19 wave swept across the nation in April and May, eviscerating demand.
Sales by the three biggest fuel retailers in the first half of July were 3.4% higher than the same period in 2019, according to preliminary data from officials with direct knowledge of the matter. That's the first growth above pre-pandemic levels since April, supported by an increase in mobility.
The rebound in Indian demand will help to support the global recovery in energy consumption, with benchmark Brent crude rallying more than 40% this year. The uptick will also boost refinery runs in Asia and aid processing margins, in addition to offering a template for trends in other countries in the region, such as Indonesia, which are now facing similar challenges.
Sales of diesel, the most widely used petroleum product, are still down about 11% from 2019, but are up 13% year-on-year.
The government has said it expects overall fuel demand to get back to pre-virus levels by the end of 2021. Together, gasoline and diesel account for more than half of oil consumption.
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Related coverage:
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Indonesia Virus Surge Has Nervy Traders Recalling India ReboundIndonesia Races to Meet Vaccination Goal as Cases Soar on DeltaIndonesia's Daily Cases Surpass India, Marking New EpicenterIndia Regains 90% of Pre-Virus Gasoline Sales as Demand Rebounds
*T
India's health situation has stabilized. Daily infections have receded after peaking at world's highest pace in May, and most stay-at-home curbs have been eased. That's prompted motorists to return to the roads, the officials said, asking not to be identified as they're not authorized to speak to media.
Spokespeople for Indian Oil Corp., Bharat Petroleum Corp., and Hindustan Petroleum Corp., declined to comment. The three retailers account for more than 90% of the nation's fuel sales.
Here's a table of the preliminary data:
*T
===
|July 1-15 ('000 | |Vs. July 1-15,
| Tons) | Y/y | 2019

==
Diesel | 2,488.1| 12.7%| -10.7%
Gasoline | 1,034.5| 18.1%| 3.4%
LPG | 1,092.7| 2.2%| -4.9%
Jet | 132.1| 20.4%| -56.1%
*T

To contact the reporter on this story:
Debjit Chakraborty in New Delhi at dchakrabor10@bloomberg.net
To contact the editors responsible for this story:
Serene Cheong at scheong20@bloomberg.net
Jake Lloyd-Smith

To view this story in Bloomberg click here:
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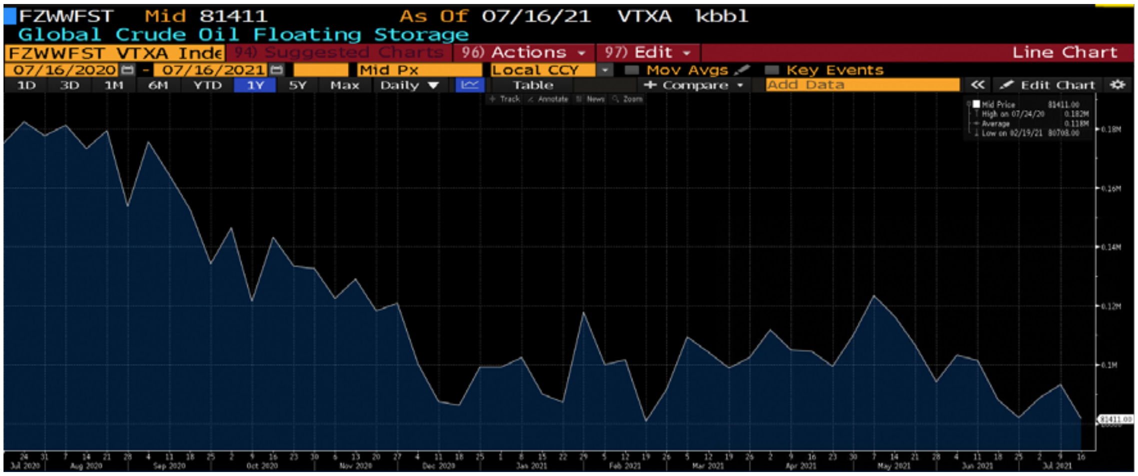

Bloomberg @TheTerminal
Crude Oil in Floating Storage 51% Lower Than Year Ago: Vortexa
2021-07-12 07:00:01.404 GMT

By Bloomberg Automation
(Bloomberg) -- The amount of crude oil held around the world on tankers that have been stationary for at least 7 days rose to 93.12m bbl as of July 9, Vortexa data show.
* That's up 1.9% from 91.37m bbl on July 2
* Asia Pacific up 6.1% w/w to 60.97m bbl
* Middle East up 0.6% w/w to 8.62m bbl
* Europe down 5.4% w/w to 6.67m bbl
* West Africa up 73% w/w to 6.46m bbl; highest since February
* North Sea down 21% w/w to 3.04m bbl
* U.S. Gulf Coast up 125% w/w to 1.30m bbl
* Company Exposure:
** Asia: Cosco Shipping Energy Transportation Co., HMM Co. Ltd., Mitsui O.S.K. Lines Ltd., Nippon Yusen KK
** Europe: Euronav NV, Frontline, Vopak
** U.S.: DHT Holdings, International Seaways, Nordic American Tankers, Teekay Tankers, Tsakos Energy Navigation
* NOTE:
** Vortexa data exclude FPSO units, oil products and Iranian condensate
** Crude oil transferred by STS isn't included until that volume has been stationary on receiving vessel for 7 days
** Data don't include vessels booked for floating storage until they are actually stationary for the minimum period
** See VTXA or DATA FLOAT for more data, which is subject to revisions, and see NI TANTRA for all tanker-tracking stories
** See SPOT FREIGHT for freight rate assessments using shipbroker data

To contact Bloomberg News for this story:
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OIL DEMAND MONITOR: Asian Mobility Stymied as U.S. Hits Record
2021-07-14 05:14:55 GMT

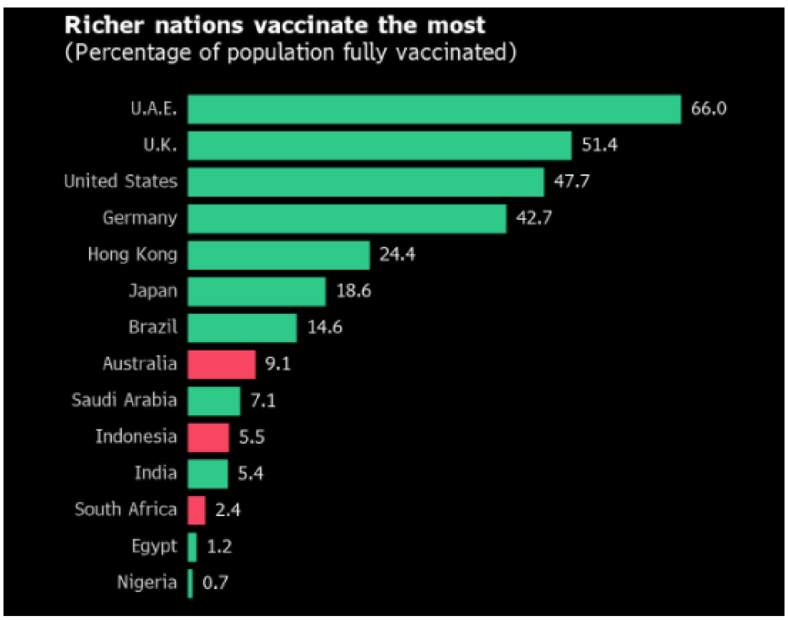
- **European air traffic gained 33% in past month: Eurocontrol**
- **Airline seat capacity falls in Australia; rises in China, U.K.**

By Stephen Voss

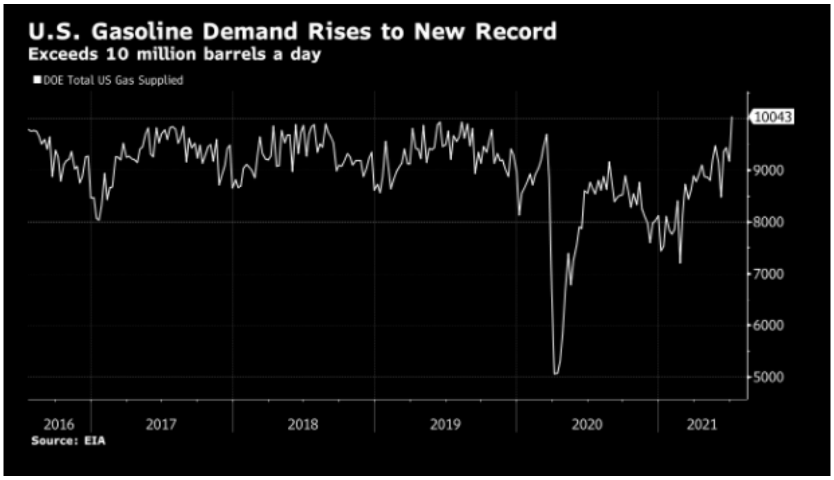
(Bloomberg) – U.S. gasoline demand jumped to a new high and European air traffic swelled by one-third in the past month as mobility accelerates in countries where a large chunk of the population is already fully vaccinated against coronavirus.

Airplane seat capacity tumbled, however, by about 16% in the past week in both Australia and South Africa, highlighting the sting of movement restrictions on fuel demand in places where a slower vaccine roll-out leaves people more vulnerable to infection.

The risk is acute in developing nations in Southeast Asia. For instance, in Indonesia, the delta variant of the virus is spreading through a population where only about 6 people in 100 are fully vaccinated, according to official statistics collected by Our World in Data.



The new U.S. record for gasoline demand of 10.04 million barrels a day was for the week ended July 2, just before the Independence Day holiday, and is an estimate from the Energy Information Administration, rather than a direct measurement of consumption. Data for the week ended July 9 will be released later Wednesday.



Football Hangover . . .
Among western Europe's five biggest cities, Paris had the most road congestion at 8 a.m. local time on Monday morning, surpassing both London and Rome, which have both held the top spot in recent weeks, according to navigation technology company TomTom NV. The Euros football championship final on Sunday evening, in which Italy beat England, may possibly have reduced commuting activity Monday morning in those countries, and both London and Rome had higher traffic flows again on Tuesday and Wednesday mornings.

None of the cities regularly tracked in this monitor had congestion above 2019 levels on Monday. Tokyo was closest, registering a decline of 18%, with Paris next at -34%. Comparable information for Chinese cities is not available.

More comprehensive data from service stations show U.K. sales of gasoline and diesel were about 7% below pre-pandemic levels in the week ended July 4.

Weekly traffic measurements by governments and road operators across Europe are on the whole very close to pre-pandemic levels. There were 3% more passenger cars on the road in Poland than in 2019, while traffic volumes in Italy, Spain and France were 3.3%, 4.6% and 11% below 2019, respectively. In the U.S., the vehicle miles traveled by passenger cars in the week ending July 4 were 3% below the level two years ago.

China Air Traffic Strong

While several nations in Asia are seeing new waves of Covid-19 infections and deaths, data from OAG Aviation shows China is still proving the most resilient in terms of air traffic. Seat capacity in China in OAG's latest week of data was 7% higher than the equivalent week in 2019, while the U.S. was 17% below. In Australia, where infections have pushed cities such as Sydney into lockdown, seat capacity dropped back below 1 million per week. U.K. seat capacity numbers rose, though the country still lags its European peers.

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

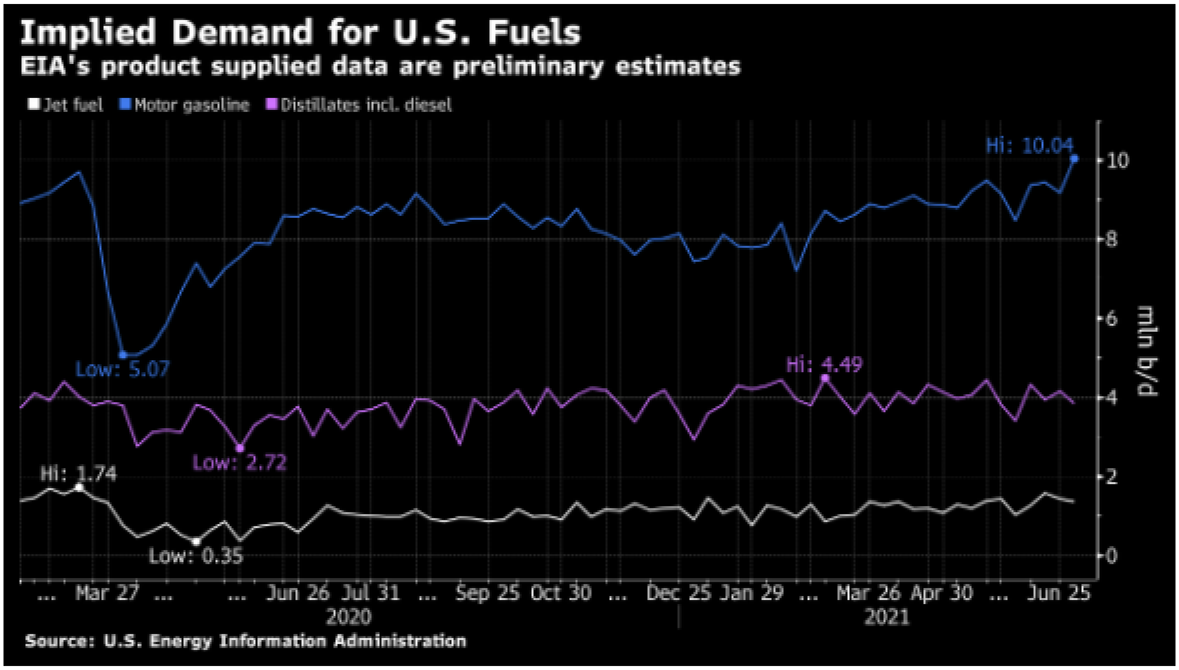
Following are the latest indicators, in the four tables below. The first two show fuel demand and mobility, the next shows air travel globally and the last is refinery activity:

Measure	Location	% y/y	% vs 2019	% m/m	Freq.	Latest as of Date	Latest Value	Source
Gasoline demand	U.S.	+15	+3	+18	w	July 2	10m b/d	EIA
Distillates demand	U.S.	+27	+8.1	+13	w	July 2	3.84m b/d	EIA
Jet fuel demand	U.S.	+48	-24	+33	w	July 2	1.37m b/d	EIA
Total oil products demand	U.S.	+19	+1.3	+22	w	July 2	21.5m b/d	EIA
All vehicles miles traveled	U.S.		unch		w	July 4	17b miles	DoT
Passenger car VMT	U.S.		-3		w	July 4	n/a	DoT
Truck VMT	U.S.		+18		w	July 4	n/a	DoT
All motor vehicle use index	U.K.	+17	-3	-2	d	July 5	97	DfT
Car use	U.K.	+18	-7	-2	d	July 5	93	DfT
Heavy goods vehicle use	U.K.	+10	+7	-1.8	d	July 5	107	DfT

Gasoline (petrol) avg sales per filling station	U.K.	+28	-6	-3	w	July 4	6,828 liters/d	BEIS
Diesel avg sales per station	U.K.	+16	-7.8	+2.9	w	July 4	9,614 liters/d	BEIS
Total road fuels sales per station	U.K.	+21	-7.1	+0.4	w	July 4	16,442 liters/d	BEIS
Gasoline	India	+5.7	-10	n/a	2/m	June 1-30	2.12m tons	Bberg
Diesel	India	-1.8	-19	+13	2/m	June 1-30	5.36m tons	Bberg
Jet fuel	India	+10	-62	n/a	2/m	June 1-30	233k tons	Bberg
Total Products	India	+1.5	-7.6	+8	m	June 2021	16.34m tons	PPAC
Passenger car traffic	Poland	+7	+3	+10	m	July 5-11	25,737	GDDKiA
Heavy goods traffic	Poland	+12	+9	-4.6	m	July 5-11	4,685	GDDKiA
Toll roads volume	France	+5.2	-11		w	July 4	n/a	Atlantia
Toll roads volume	Italy	+14	-3.3		w	July 4	n/a	Atlantia
Toll roads volume	Spain	+14	-4.6		w	July 4	n/a	Atlantia
Toll roads volume	Brazil	+18	+1.2		w	July 4	n/a	Atlantia
Toll roads volume	Chile	+115	-13		w	July 4	n/a	Atlantia
Toll roads volume	Mexico	+25	+3.4		w	July 4	n/a	Atlantia
All vehicles traffic	Italy	+15	+12	+13	m	June	n/a	Anas
Heavy vehicle traffic	Italy	+17	-1	+9	m	June	n/a	Anas
Gasoline	Portugal	+28	-16	+5.1	m	May	79k tons	ENSE
Diesel	Portugal	+12	-12	-0.1	m	May	380k tons	ENSE
Jet fuel	Portugal	+298	-68	+39	m	May	46k tons	ENSE
Gasoline	Spain	+40	+1.1		m	June	500k m3	Exolum
Diesel	Spain	+15	-8		m	June	2199k m3	Exolum
Jet fuel	Spain	+371	-61		m	June	268k m3	Exolum

The frequency column shows d for data updated daily, w for weekly, 2/m for twice a month and m for monthly.

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



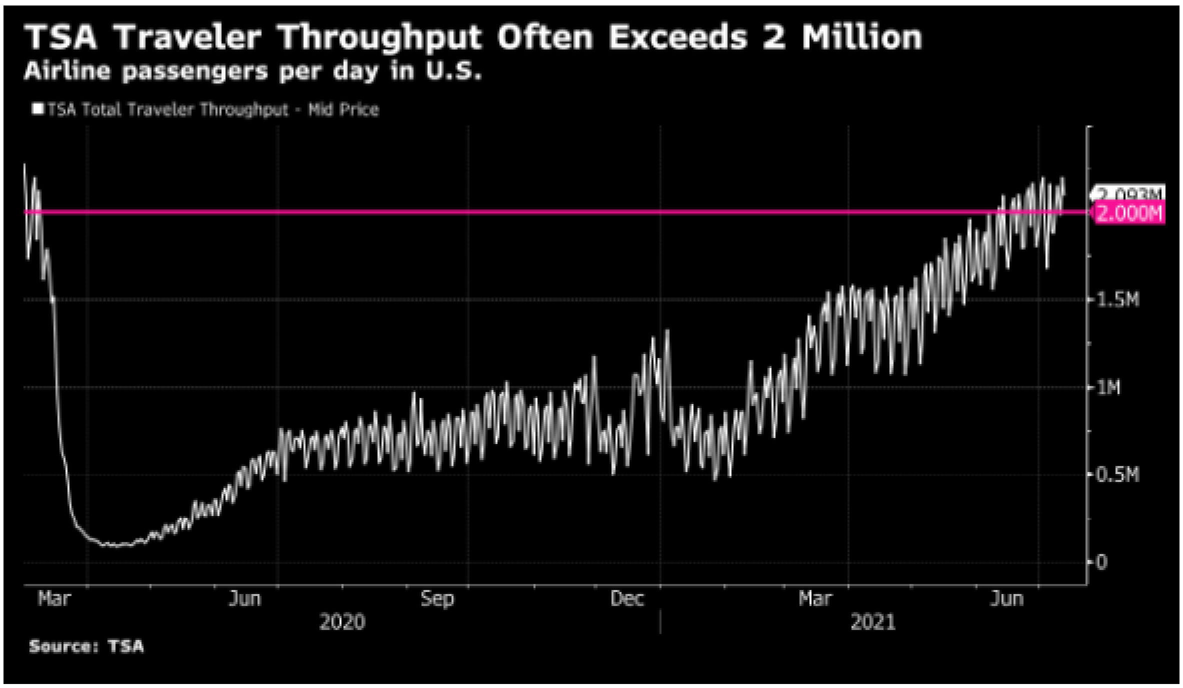
City Congestion:

Measure	Location	% chg vs 2019	% chg m/m	July 12	Jul. 5	Jun. 28	Jun. 21	Jun. 14	Jun. 7	May 31	May 24	May 17	May 10
		(July 12)		Minutes of congestion at 8am local time									
Congestion	Tokyo	-18	+2	31	36	27	28	30	27	26	29	31	28
Congestion	Mumbai	-87	+33	5	6	5	5	4	4	2	2	3	2
Congestion	New York	-42	-17	18	0	16	16	22	23	2	20	17	19
Congestion	Los Angeles	-51	-6	17	3	17	16	19	20	3	21	19	19
Congestion	London	-49	-51	19	34	38	37	39	40	3	41	40	41
Congestion	Rome	-52	-32	23	35	13	36	34	49	24	38	34	40
Congestion	Madrid	-64	-43	13	14	16	18	22	27	22	23	19	24
Congestion	Paris	-34	-30	29	39	37	44	42	42	37	3	32	31
Congestion	Berlin	-54	-43	16	16	19	28	28	28	26	3	25	24
Congestion	Mexico City	-56	-16	22	23	24	21	26	24	22	23	23	14
Congestion	Sao Paulo	-49	-3	22	20	23	26	23	26	28	23	22	22

Source: TomTom. Note: M/m comparison is July 5 vs June 7. New York and Los Angeles experienced less traffic on July 5 because of the Independence Day public holiday, which also skewed m/m comparisons. TomTom has been unable to provide Chinese data since late April.

Air Travel:

Airline passenger throughput	U.S.	+200	-17	+16	d	July 12	2.09m people	TSA
Commercial flights	Worldwide	+54	-26	+11	d	July 12	93,019	FlightRadar24
Air traffic (flights)	Europe		-37	+33	d	July 12	22,796	Eurocontrol
Seat capacity	Worldwide	+48	-33		w	July 12	79.83m	OAG
Seat cap.	China	+28	+7		w	July 12	18.14m	OAG
Seat cap.	U.S.	+70	-17		w	July 12	19.56m	OAG
Seat cap.	India	+66	-40		w	July 12	2.40m	OAG
Seat cap.	Japan	-20	-56		w	July 12	1.88m	OAG
Seat cap.	Australia	+155	-57		w	July 12	929k	OAG
Seat cap.	Brazil	+195	-35		w	July 12	1.72m	OAG
Seat cap.	France	+67	-38		w	July 12	1.60m	OAG
Seat cap.	Germany	+63	-54		w	July 12	1.56m	OAG
Seat cap.	U.K.	+19	-70		w	July 12	1.17m	OAG
Seat cap.	S. Africa	+252	-70		w	July 12	180k	OAG



Refineries:

Measure	Location	y/y chg	vs 2019 chg	m/m chg	Latest as of Date	Latest Value	Source
Crude intake	U.S.	+12%	-7.6%	+1.2%	July 2	16.1m b/d	EIA
Utilization	U.S.	+15 ppt	-2.5 ppt	+0.9 ppt	July 2	92.2 %	EIA
Utilization	Gulf Coast U.S.	+11 ppt	-5.2 ppt	-1.6 ppt	July 2	91.3 %	EIA
Utilization	East Coast U.S.	+37 ppt	+20 ppt	-0.6 ppt	July 2	89.1 %	EIA
Utilization	Midwest U.S.	+16 ppt	+1 ppt	+7.9 ppt	July 2	98.8 %	EIA
Apparent Oil Demand	China	-0.9%		+4.8%	May 2021	13.58m b/d	NBS
Indep. refs run rate	Shandong province, China	-1.5 ppt	+14 ppt	+1.7 ppt	July 9	73.7 %	SCI99
State refs run rate	East China	-0.6 ppt	+2 ppt	+2.5 ppt	June 30	78.8 %	SCI99
State refs run rate	South China	-4.6 ppt	+0.3 ppt	-4.3 ppt	June 30	82.4 %	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.

--With assistance from Julian Lee.

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
John Deane, Stephen Voss

Excerpts Delta Air Lines Q2 2021 Earnings Call July 14, 2021
From Bloomberg Transcripts

Items from Mgmt Opening Statement
More encouragingly, the momentum is continuing as we exited June with the demand environment that's accelerating. Domestic leisure demand and yields are above June quarter, 2019 levels and we see clear signs of business in international demand recovery heading into the fall.

We are now in active recovery of our business and the challenges of getting our airline fully back to the service level our customers expect and deserve is daunting in light of the huge surge in demand that we are experiencing

We are starting to see signs of a resurgence of business in international travel both of which are supporting the next leg of the revenue recovery. And we're well positioned to take advantage of both, with leading domestic corporate share and a strong global network.

With 72% of our employees vaccinated, we officially reopened our own offices last month in June, and as I interact with other CEOs, I'm encouraged to hear about their own plans to accelerate their return to office. That sentiment is coming through loud and clear in our most recent corporate survey with almost 95% of our accounts indicating they'll be returning to their offices by the end of this year.

I'm also encouraged by the strength that we're seeing in international. While we know international demand recovery will be very choppy and uneven, we're seeing strong bookings to Europe when countries open their borders. From our experience in the U.S., we are seeing the impact that widespread vaccinations have on reopening the economy.
We know the same will be true for the rest of the world over time, but are mindful of the risks that new variants posed to the pace of recovery and our team will stay very disciplined in restoring international capacity

Corporate travel volumes accelerated in May and June with almost 95% of our accounts booking travel in the month of June. We're also beginning to see a return of consulting and sales related travel and higher volumes in traditionally business heavy markets like New York City and Boston.
Our recent corporate survey results show that over 90% of our corporate accounts anticipate travel volumes to increase in the September quarter up from just 33% in the March quarter. In addition to the survey results, our close engagement with customers give us increased confidence of the acceleration of business travel, especially as we move towards the post Labor Day period as schools and offices continue to reopen.
We expect domestic corporate volumes will recover between 55% and 60% of 2019 levels by the end of the September quarter, up from 40% at the end of the June quarter. Despite volatility in global COVID recovery trends, international travel is accelerating with capacity and load factors increasing as we head into the fall.

Items From Q&A
So, I'm pretty optimistic about how the results could play out in the transatlantic. And that's really, we have 35% to 40% of our travel still missing with the European origin piece not open for sale, and with business really not recovering at the same level as leisure. So, pretty optimistic about where we can get to on this leg, but there's a lot more to come in the transatlantic. In Latin, it's really the tale of two markets, one is the close-in U.S. point of origin leisure market, as well as Mexico business. Both of these are actually exceeding 2019 levels. So, short whole Latin is doing quite well and we continue to expect that to be very strong as we move into the more traditional leisure season in the late fall.

Source: Bloomberg Transcripts

EXTENDED RANGE FORECAST OF ATLANTIC SEASONAL HURRICANE ACTIVITY AND LANDFALL STRIKE PROBABILITY FOR 2021

We have increased our forecast slightly and continue to forecast an above-average 2021 Atlantic basin hurricane season. Current neutral ENSO conditions are anticipated to persist for the next several months. Sea surface temperatures averaged across most of the tropical Atlantic are now near to slightly above normal, and most of the subtropical North Atlantic remains warmer than normal. Elsa's development and intensification into a hurricane in the tropical Atlantic also typically portends an active season. We anticipate an above-normal probability for major hurricanes making landfall along the continental United States coastline and in the Caribbean. As is the case with all hurricane seasons, coastal residents are reminded that it only takes one hurricane making landfall to make it an active season for them. They should prepare the same for every season, regardless of how much activity is predicted.

(as of 8 July 2021)

By Philip J. Klotzbach[1], Michael M. Bell[2], and Jhordanne Jones[3]

In Memory of William M. Gray[4]

This discussion as well as past forecasts and verifications are available online at
http://tropical.colostate.edu

Jennifer Dimas, Colorado State University media representative, is coordinating media inquiries into this verification. She can be reached at 970-491-1543 or
Jennifer.Dimas@colostate.edu

Department of Atmospheric Science
Colorado State University
Fort Collins, CO 80523

Project Sponsors:

[1] Research Scientist
[2] Associate Professor
[3] Graduate Research Assistant
[4] Professor Emeritus

ATLANTIC BASIN SEASONAL HURRICANE FORECAST FOR 2021

Forecast Parameter and 1991-2020 Average (in parentheses)	Issue Date 8 April 2021	Issue Date 3 June 2021	Issue Date 8 July 2021	Observed Thru 7 July 2021	Remainder of Season Forecast
Named Storms (NS) (14.4)	17	18	20*	5	15
Named Storm Days (NSD) (69.4)	80	80	90	12	78
Hurricanes (H) (7.2)	8	8	9	1	8
Hurricane Days (HD) (27.0)	35	35	40	1.5	38.5
Major Hurricanes (MH) (3.2)	4	4	4	0	4
Major Hurricane Days (MHD) (7.4)	9	9	9	0	9
Accumulated Cyclone Energy (ACE) (123)	150	150	160	12	148
Net Tropical Cyclone Activity (NTC) (135%)	160	160	170	16	154

*Total forecast includes Ana, Bill, Claudette, Danny and Elsa which have formed in the Atlantic as of July 7th.

PROBABILITIES FOR AT LEAST ONE MAJOR (CATEGORY 3-4-5) HURRICANE LANDFALL ON EACH OF THE FOLLOWING COASTAL AREAS (AFTER 7 JULY):

1) Entire continental U.S. coastline - 68% (average for last century is 52%)

2) U.S. East Coast Including Peninsula Florida - 43% (average for last century is 31%)

3) Gulf Coast from the Florida Panhandle westward to Brownsville - 43% (average for last century is 30%)

PROBABILITY FOR AT LEAST ONE MAJOR (CATEGORY 3-4-5) HURRICANE TRACKING INTO THE CARIBBEAN (10-20°N, 88-60°W) (AFTER 7 JULY):

1) 57% (average for last century is 42%)

ABSTRACT

Information obtained through early July 2021 indicates that the 2021 Atlantic hurricane season will have activity above the 1991-2020 average. Ana, Bill, Claudette, Danny and Elsa have already formed as of 7 July. We estimate that the full (e.g., including storms that have already formed) 2021 season will have 9 hurricanes (full-season average is 7.2), 20 named storms (full-season average is 14.4), 90 named storm days (full-season average is 69.4), 40 hurricane days (full-season average is 27.0), 4 major (Category 3-4-5) hurricanes (full-season average is 3.2) and 9 major hurricane days (full-season average is 7.4). The probability of U.S. major hurricane landfall for the remainder of the season is estimated to be about 130 percent of the long-period full-season average. We expect Atlantic basin Accumulated Cyclone Energy (ACE) and Net Tropical Cyclone (NTC) activity in 2021 to be approximately 130 percent of their long-term averages.

This forecast is based on an extended-range early July statistical prediction scheme that was developed using 39 years of past data. Analog predictors are also utilized. We are also including statistical/dynamical models based off data from both the ECMWF SEAS5 model and the Met Office GloSea6 model as two additional forecast guidance tools. The statistical model, the two statistical/dynamical models and the analog model all call for an above-average Atlantic hurricane season. We also present probabilities of exceedance for hurricanes and Accumulated Cyclone Energy to give interested readers a better idea of the uncertainty associated with these forecasts.

The tropical Pacific is currently characterized by neutral ENSO conditions, and we anticipate that neutral ENSO conditions are the most likely scenario for the peak of this year's Atlantic hurricane season. It appears very unlikely that El Niño conditions will develop over the next few months. El Niño typically reduces Atlantic hurricane activity through increases in vertical wind shear.

The tropical Atlantic currently has near to slightly above-normal sea surface temperatures, while most of the subtropical North Atlantic is warmer than normal. This sea surface temperature configuration is typically associated with more active hurricane seasons. In addition, while early season Atlantic hurricane activity is typically not associated with the remainder of the season's activity, hurricanes in the tropical Atlantic and eastern Caribbean (e.g., Elsa) are typically associated with very active Atlantic hurricane seasons.

Coastal residents are reminded that it only takes one hurricane making landfall to make it an active season for them, and they need to prepare the same for every season, regardless of how much activity is predicted.

The early July forecast has good long-term skill when evaluated in hindcast mode. The hindcast skill of CSU's forecast continues to improve with its early August update.

Why issue extended-range forecasts for seasonal hurricane activity?

We are frequently asked this question. Our answer is that it is possible to say something about the probability of the coming year's hurricane activity which is superior to climatology. The Atlantic basin has the largest year-to-year variability of any of the global tropical cyclone basins. People are curious to know how active the upcoming season is likely to be, particularly if you can show hindcast skill improvement over climatology for many past years.

Everyone should realize that it is impossible to precisely predict this season's hurricane activity in early July. There is, however, much curiosity as to how global ocean and atmosphere features are presently arranged as regards to the probability of an active or inactive hurricane season for the coming year. Our early July statistical and statistical/dynamical hybrid models show strong evidence on ~25-40 years of data that significant improvement over a climatological forecast can be attained. We would never issue a seasonal hurricane forecast unless we had models developed over a long hindcast period which showed skill. We also now include probabilities of exceedance to provide improved quantification of the uncertainty associated with these predictions.

We issue these forecasts to satisfy the curiosity of the general public and to bring attention to the hurricane problem. There is a general interest in knowing what the odds are for an active or inactive season. One must remember that our forecasts are based on the premise that those global oceanic and atmospheric conditions which preceded comparatively active or inactive hurricane seasons in the past provide meaningful information about similar trends in future seasons.

It is also important that the reader appreciate that these seasonal forecasts are based on statistical and dynamical models which will fail in some years. Moreover, these forecasts do not specifically predict where within the Atlantic basin these storms will strike. The probability of landfall for any one location along the coast is very low and reflects the fact that, in any one season, most U.S. coastal areas will not feel the effects of a hurricane no matter how active the individual season is.

https://www.nikkei.com/article/DGXZQOUA15CZB0V10C21A7000000/

Nuclear power plant has been in operation for over 60 years.

July 16, 2021 2:00


Kansai Electric Power's Mihama Nuclear Power Station Unit 3 (Mihama Town, Fukui Prefecture)

It was revealed on the 15th that the theory of extending the operation period of nuclear power plants has emerged within the government. Currently, it has been 40 years in principle and up to 60 years since the start of operation. There is a plan to look at it on a "working basis" excluding the period stopped by the NRA review, and a plan to abolish the upper limit of the operating period. If realized, it will effectively drive for more than 60 years. Rebuilding and new construction will be postponed, and requests to extend the life of old equipment will increase.

In June, Kansai Electric Power 's Mihama Nuclear Power Plant Unit 3 (Mihama Town, Fukui Prefecture) restarted for the first time as a nuclear power plant that has been in operation for more than 40 years. Since the nuclear power plant and other facilities that will reach the legal upper limit of 60 years will appear in the 2030s, the ideal way of long-term operation was the focus. It is expected that the next basic energy plan, which will be presented on the 21st, will consider issues related to long-term operation of nuclear power plants.

The 40-year rule was introduced by the revision of the Reactor Regulation Law after the accident at TEPCO's Fukushima Daiichi Nuclear Power Plant. Only once can be extended for up to 20 years. Legal amendments are needed to lift the cap and allow multiple extensions. Except for the suspension period required by the LDP and the business community, it seems unnecessary to amend the law.

Many people are worried about safety even after driving for more than 40 years. If further extension is permitted, it is assumed that it will be combined with the tightening of regulations such as the addition of safety measures.

https://www.nhtsa.gov/press-releases/consumer-alert-important-chevrolet-bolt-recall-fire-risk

Consumer Alert: Important Chevrolet Bolt Recall for Fire Risk

Owners should park their vehicles outside until further notice

Share:

July 14, 2021 | Washington, DC

The National Highway Traffic Safety Administration is urging owners of select Model Year 2017-2019 Chevrolet Bolt vehicles to park their cars outside and away from homes due to the risk of fire.

Owners of these vehicles should park their vehicles outside away from homes and other structures immediately after charging and should not leave their vehicles charging overnight, according to General Motors.

The vehicles that should be parked outside are those that were originally recalled in November 2020 for the potential of an unattended fire in the high-voltage battery pack underneath the backseat's bottom cushion. The affected vehicles' cell packs have the potential to smoke and ignite internally, which could spread to the rest of the vehicle and cause a structure fire if parked inside a garage or near a house. This recall affected 50,932 MY 2017-19 Chevrolet Bolt vehicles.

Vehicles should be parked outside regardless of whether the interim or final recall remedies have been completed. NHTSA is aware of two recent Chevrolet Bolt EV fires in vehicles that received the recall remedy.

NHTSA opened an investigation (PE 20-016) in October 2020, continues to evaluate the information received, and is looking into these latest fires.

Vehicle owners can visit NHTSA.gov/recalls and enter their 17-digit vehicle identification number to see if their vehicle is affected under this recall. If it is, vehicle owners should call their nearest Chevrolet dealership immediately to schedule a free repair. For more information on this recall, visit www.chevy.com/boltevrecall.

Owners can also download NHTSA's new SaferCar app for Apple or Android. Enter the vehicle, tires, car seat, or other vehicle equipment, and the app will push a notification if a recall is issued.

We're in an unprecedented time. The COVID-19 pandemic has introduced threats to lives, livelihoods, health and relationships. Challenges for both individuals and organizations come from the resulting physical and mental-health risks, and the consequences of each. Since the declaration of the global crisis in early 2020, there has been a significant mental-health decline among the working population, as shown in the Mental Health Index by LifeWorks™, a monthly report that evaluates the mental health of employed adults in Canada, the United States, the United Kingdom and Australia. Such a decline is consequential and the long-term effects may last well beyond vaccine roll out, as discussed in Deloitte's article Uncovering the Hidden Iceberg: Why the human impact of COVID-19 could be a third crisis. Various studies, including Deloitte's The ROI of workplace mental health programs, already highlighted the importance and financial implications of employee mental health to organizations pre-pandemic.

We have also seen an upending of long-standing patterns. For example, counter to the pre-pandemic trend, the mental health of managers has been more compromised than has that of employees who don't manage others, as shown in LifeWorks Mental health for people leaders during COVID-19: Leading on the edge.

For organizations to holistically address mental health, all employee groups should be considered, however, senior leaders had yet to be assessed in a meaningful way. We undertook the current study to fill that gap and help companies gauge their overall mental health.

LifeWorks Research Group and Deloitte Canada conducted the research for this study in the spring of 2021 in collaboration with the CHRO20.[1] Both quantitative and qualitative data was collected.[2]

Survey participants included 1,158 senior leaders[3] from 11 large organizations in the private and public sectors. Sixty-six per cent (66%) of respondents reside in Canada; 18 per cent in the United States; 10 per cent in Europe, the Middle East, and Africa (EMEA); 4 per cent in the Asia-Pacific region (APAC); one per cent in Latin America (LATAM); and one per cent in other regions.

Organizations, among others, include:

- Bell Canada
- City of Toronto
- Deloitte
- Ontario Teachers' Pension Plan
- Thomson Reuters
- University of Toronto

The findings demonstrate that senior leaders have been experiencing extraordinary strain

- More than eight in 10 leaders (82%) reported exhaustion indicative of burnout risk. Ninety-six per cent of **those who report exhaustion indicate that their mental health has declined**.

- **Slightly more than half (51%) of participants had been contemplating exiting their roles**; of this subset, strategies included resigning (23%), moving to a less demanding position (16%), retiring (15%), taking a leave of absence (13%), and working part-time (6%). Some considered more than one option.

- The top stressor (68%) was an **increase in work volume** compared with pre-pandemic levels.

- The second-highest reported stressor (62%) was related to **the desire to provide adequate support for the wellbeing of staff**.

- **Number of extra hours worked** (over and above leaders' typical long hours) **and reports of mental-health decline** were strongly correlated.

- More than four in 10 respondents (41%) indicated **self-stigma** around the idea of acknowledging or accepting any potential mental health challenge.

- More than half (55%) were concerned about **workplace stigma having an impact on their careers** if they had a mental health issue and anyone were to find out.

- Six in 10 (63%) said they **don't make time for their personal wellbeing**, either consistently or at all.

- **Support from their own leaders is essential, but it's not a sufficient buffer** against senior leaders' stress.

- Sixty-five per cent of those reporting worsened peer relationships also reported worsened mental health, and 59 per cent of those with improved peer relationships also enjoyed improved productivity; thus, **peer relationships were strongly and directly associated with mental health and productivity**.

- One third (32%) indicate that their **relationships with peers worsened during the pandemic.**

In almost all areas, the findings show that mental strain and its consequences affect senior leaders more strongly than they affect employees and mid-level managers.[4]

Increased work demands and decreased control create undue strain

To understand these findings, consider that the pandemic has increased the work demands, risk, and complexity for senior leaders, while introducing many factors outside of their control.

In this situation, Karasek & Theorell's well-known demand-control-support theory of job strain — which has been used to explain depression, exhaustion, job dissatisfaction, and decline in physical health when there's a pronounced disparity between demand, control and support — would suggest a strong need for increased support for this group to balance the widened gap between workplace demands and sense of control.

The current levels of wellbeing and resilience reported by senior leaders pose a significant business risk

A strong and sustainable culture of wellbeing and resilience needs to apply to everyone. When leaders experience wellbeing and resilience they are in a better position to provide support to their people. Our survey findings, however, suggest that leaders feel an unequal burden. As compared with non-leaders, more of them perceive that they will suffer negative career consequences if ever they were to face mental-health challenges.[5,6] Additionally, while they are concerned with supporting and caring for the wellbeing and resilience of their employees, they don't necessarily take time to focus on these matters when it applies to them personally.

These issues have significant implications for organizations and as such, the overall economic recovery. The potential for a loss of talent is evident, and the behaviours that emerge under extreme strain, such as irritability and extreme perfectionism, may unintentionally negatively affect the broader workforce and organizational culture.

A call to action is urgent, as personal and business risks will likely increase

Among senior leaders, the focus is on their people, customers and business continuity, as well as complex and ongoing operational changes. The need for this focus has increased during the pandemic and is expected to continue to increase beyond the immediate crisis. Their resilience, adaptability, and leadership skills will be put to the test, as most organizations will continue to change operating models, adjust to evolving customer needs, and convert to increasingly distributed workforces. All of this is expected to require a reset of overall organizational culture, and will impact employee productivity and wellbeing. Leaders will thus need a surplus of energy, clarity and stamina to ensure workforces and businesses thrive in our next normal. Accordingly, the current research points to calls to action in at least four areas:

1. **Peer relationships**. These are important for wellbeing and productivity, particularly in turbulent times. Strong peer relationships offer both social support and strategic business value. Peer alignment at the senior level is essential to leaders' self-permission to prioritize work, as well as to their ability to successfully manage the impact of that prioritization.

2. **Stigma concerning mental health**. Regardless of who may be experiencing a given challenge, stigma is harmful in the workplace. Unspoken expectations appear to imply that senior leaders should not have mental-health challenges, which is likely why they reported fearing that any such issues would affect their careers. The specific drivers of stigma for this group need to be addressed.

3. **Personal support**. Leaders need support to help them manage the increased strain they have been facing during this time and are expected to continue to face post-pandemic. A continuum of support can help to shape thinking and behaviour in order to promote sustainable high performance and provide the type and level of assistance needed to address sometimes complex work, personal and family challenges.

4. **Clear guidance and tools**. Leaders have an impact on their organizations as a whole; they are also accountable for their teams and are concerned with supporting the wellbeing of their employees. Guidance, training and ongoing coaching can help them in their roles and, as a result, help their teams' wellbeing.

"All of the other members of my household have struggled, sometimes significantly, with mental-health challenges this year.... Balancing my support... while [continuing to appear] strong [at] work has been hard."

Findings

The mental health and resilience of senior leaders is **significantly strained**, as evidenced by the prevalence of burnout indicators in this group.

Exhaustion was reported in 91 per cent of leaders in the public sector and 77 per cent in the private sector, and across 89 per cent of women and 75 per cent of men leaders.

82%
Regularly finish work feeling mentally and/or physically exhausted

43%
Report increased irritability

59%
Are unable to relax or pause activity

"There is an expectation that senior leaders will get the job done, no matter what."

49%
Have difficulties sleeping

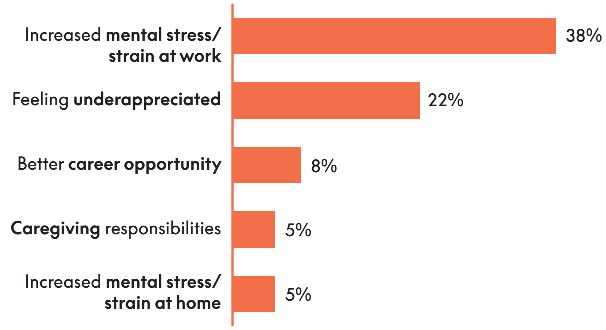
38%
Have reduced energy or emotional changes

A significant risk for organizations is **the loss of senior talent**, with slightly over half considering leaving their positions or downshifting. Fifty-one per cent have been contemplating exiting their roles via various different means, with some considering more than one such option.

Women and those in the public sector were slightly more inclined to consider resigning.

The most prevalent reason (at 38%) for considering leaving or downshifting was **increased mental stress/strain at work**. Additionally, almost one-quarter (22%) indicated feeling underappreciated.

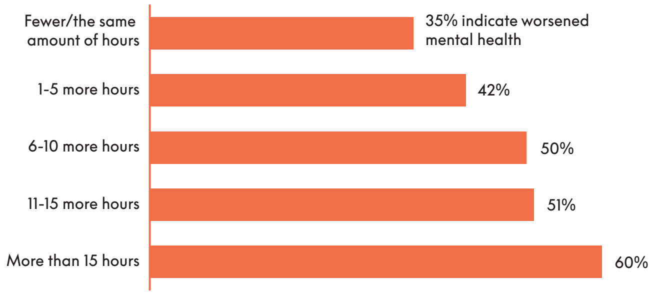
Women tended to report mental stress as an exiting factor; for men, it was being underappreciated.



> **"Work demands do not stop, they are staggering, therefore taking time off feels like a weight and detrimental, so I resist taking it when I know I need it to be effective, creative and role model sound leadership behaviours."**

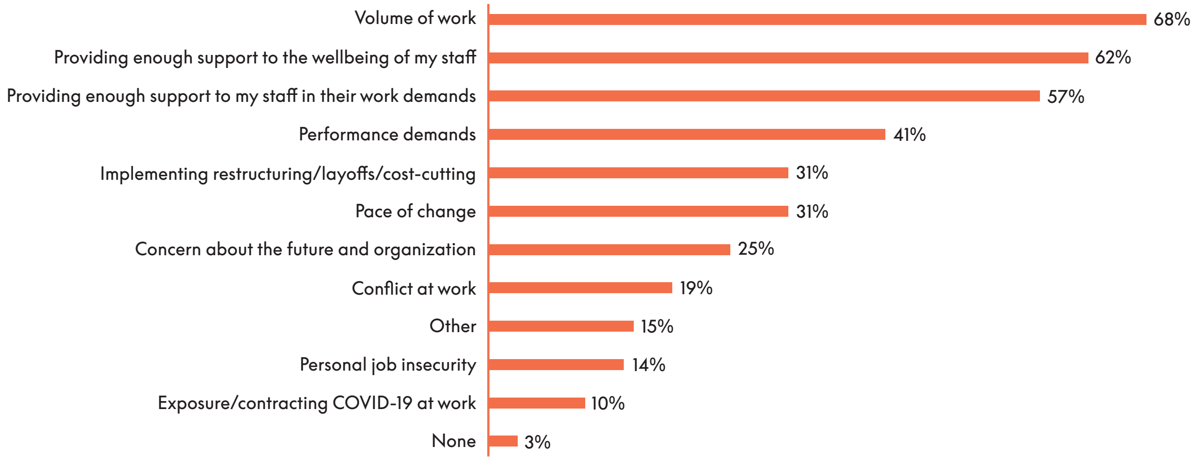
Seventy-nine per cent of respondents reported working more hours than typical since the start of the pandemic. The **number of additional hours is strongly correlated to self-reported declines in mental health**. However, due to factors including changes in the nature of work, dedicating either the same number of hours (19%) or fewer (2%) didn't preclude a negative impact, with 35 per cent of this combined subgroup indicating a decline in mental health.

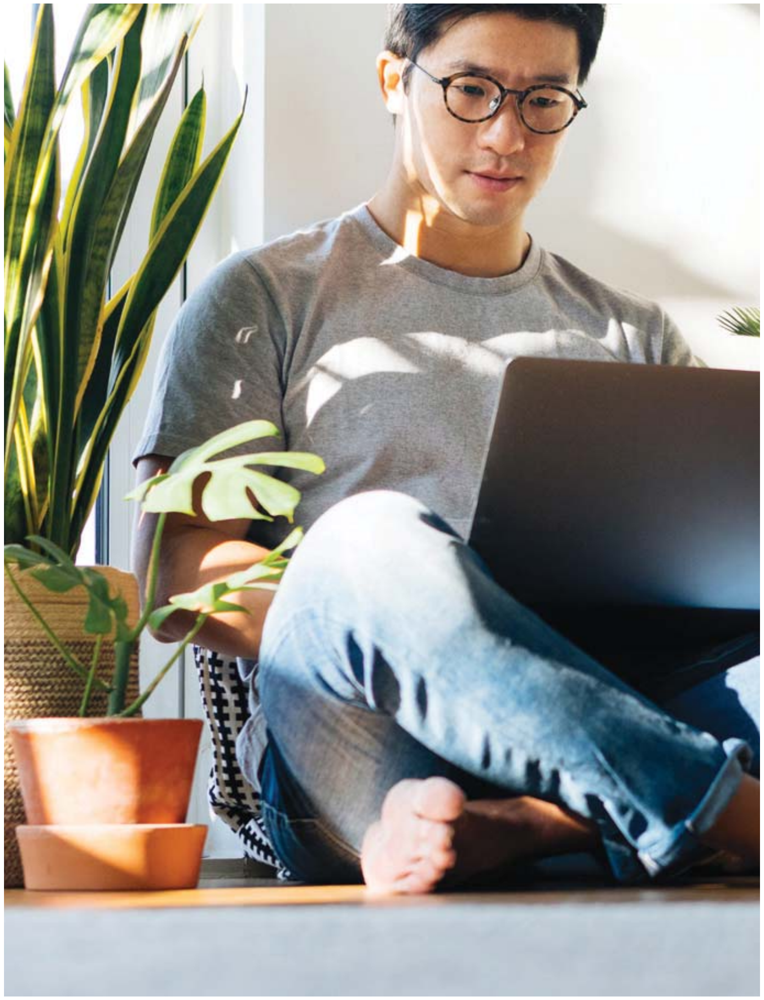
In general, women and those in the public sector worked longer additional hours.



LifeWorks | Deloitte.

In addition to sheer work volume, a top source of professional stress for leaders was **concern about providing enough support for the wellbeing of staff.**





Self-stigma is apparent with more than four in 10 survey subjects indicating that they would find it difficult to acknowledge or accept having a mental health issue.

41% would find **difficult to acknowledge or accept** if they had a mental health issue

There is also a strong perception of **work-related stigma about mental-health issues**, with the majority admitting concern about their career opportunities in the event that they faced such a challenge, and their employer was aware of this.

55% would be concerned that their career opportunities would be limited if their employer was aware that they had a mental health issue

"If I am being honest, I probably have too much pride to ask for help."

"[Regarding workplace stigma,] leaders feel that there are different rules for them."

"I would be concerned that if others knew I had a mental-health issue, it would be seen as a reflection on my capabilities and resilience as a senior leader."

Intentional and committed self-care is an issue for senior leaders, given that the majority are **inconsistent about making time for their own wellbeing**.

55% inconsistently make time for their own wellbeing

37% consistently make time for their own wellbeing

10% do not make time for their wellbeing

The **support of peers is important for resilience**, yet almost one-third (32%) of leaders indicated that their relationships with peers have worsened during the pandemic.

Overall, 37 per cent of those in the public sector and 29 per cent in the private sector reported that peer relationships have worsened.

59% report that work peers are helpful in supporting resilience yet

32% of peer relationships have worsened

"Sometimes my manager is in a worse place than I am, which is totally understandable, but [this] means I'd rather not bother her with my stuff."

Additionally, worsened peer relationships correlated with worsened mental health, while **productivity improved in conjunction with improved peer relationships**.

65% of leaders reporting worsened **peer relationships have worsened mental health**

59% of leaders reporting improved peer relationships have improved productivity

LifeWorks | Deloitte.

Dan Tsubouchi @Energy_Tidbits · 2h

How does he do it? Once again, #SaudiEnergyMinister Abdulaziz gets this collection of #OPEC+ countries to agree. reinforces if you could invite 3 people for dinner, he should be on everyone's list. He is on mine! #Oil companies everywhere should be thanking him again. #OOTT

> **Dan Tsubouchi** @Energy_Tidbits · Jul 1
>
> If you could invite 3 people for dinner? #SaudiEnergyMinister Abdulaziz should be on everyone's list, he is on mine! "The Man" who saved the #Oil market and shows he is just a good person with a heartfelt tribute. #OOTT Thx @dan_murphy for video. twitter.com/dan_murphy/sta...

4 7 16

Dan Tsubouchi @Energy_Tidbits · 4h

#OPEC+ deal: Production increasing +0.4 mmb/d monthly starting Aug 2021 until 5.8 mmb/d production adjustment is eliminated. Higher baselines Iraq, Kuwait, KSA, Russia, UAE. Dec 2021 assess market and OPEC+ country performance. #OOTT #Oil

https://www.opec.org/opec_web/en/press_room/6512.htm

19th OPEC and non-OPEC Ministerial Meeting concludes

No 21/2021, Vienna, Austria 18 Jul 2021

The 19th OPEC and non-OPEC Ministerial Meeting (ONOMM), held via videoconference, concluded on Sunday 18 July 2021.

The Meeting noted the ongoing strengthening of market fundamentals, with oil demand showing clear signs of improvement and OECD stocks falling, as the economic recovery continued in most parts of the world with the help of accelerating vaccination programmes.

The Meeting welcomed the positive performance of Participating Countries in the Declaration of Cooperation (DoC). Overall conformity to the production adjustments was 113% in June (including Mexico), reinforcing the trend of high conformity by Participating Countries.

In view of current oil market fundamentals and the consensus on its outlook, the Meeting resolved to:

Reaffirm the Framework of the Declaration of Cooperation, signed on 10 December 2016 and further endorsed in subsequent meetings, including on 12 April 2020.

Extend the decision of the 10th OPEC and non-OPEC Ministerial Meeting (April 2020) until the 31st of December 2022.

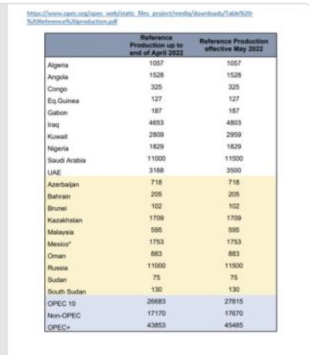
Adjust upward their overall production by 0.4 mb/d on a monthly basis starting August 2021 until phasing out the 5.8 mb/d production adjustment, and in December 2021 assess market developments and Participating Countries' performance.

Continue to adhere to the mechanism to hold monthly OPEC and non-OPEC Ministerial Meetings for the entire duration of the Declaration of Cooperation, to assess market conditions and decide on production level adjustments for the following month, endeavoring to end production adjustments by the end of September 2022, subject to market conditions.

Adjust, effective 1st of May 2022, the baseline for the calculations of the production adjustments according to the attached table (table 1).

Reiterate the critical importance of adhering to full conformity and taking advantage of the extension of the compensation period until the end of September 2021. Compensation plans should be submitted in accordance with the statement of the 15th OPEC and non-OPEC Ministerial Meeting.

The meeting decided to hold the 20th OPEC and non-OPEC Ministerial Meeting on 1 September 2021.



https://www.opec.org/opec_web/static_files_project/media/downloads/Table%20-%20Reference%20production.pdf

	Reference Production up to end of April 2022	Reference Production effective May 2022
Algeria	1057	1057
Angola	1528	1528
Congo	325	325
Eq Guinea	127	127
Gabon	187	187
Iraq	4653	4803
Kuwait	2809	2959
Nigeria	1829	1829
Saudi Arabia	11000	11500
UAE	3168	3500
Azerbaijan	718	718
Bahrain	205	205
Brunei	102	102
Kazakhstan	1709	1709
Malaysia	595	595
Mexico*	1753	1753
Oman	883	883
Russia	11000	11500
Sudan	75	75
South Sudan	130	130
OPEC 10	26683	27815
Non-OPEC	17170	17670
OPEC+	43853	45485

1 1 8

Dan Tsubouchi @Energy_Tidbits · 14h

Doesn't #Cheniere's $TOU supply deal signal FID on Corpus Christi Stage 3 #LNG has to be any day now? 15-yr gas supply starting in <18 mths for Stage 3 that is fully permitted but yet to be FID. Fits picture #LNGSupplyGap is coming faster and sooner. #NatGas

https://lngir.cheniere.com/news-events/press-releases/detail/224/cheniere-corpus-christi-stage-iii-and-tourmaline-sign

Cheniere Corpus Christi Stage III and Tourmaline Sign Long-Term Gas Supply Agreement

JULY 15, 2021 5:02PM EDT

HOUSTON--(BUSINESS WIRE)-- Cheniere Energy, Inc. ("Cheniere") (NYSE American: LNG) announced today that its subsidiary, Corpus Christi Liquefaction Stage III, LLC ("Corpus Christi Stage III"), has entered into a long-term gas supply agreement ("GSA") with Tourmaline Oil Marketing Corp. ("Tourmaline"), a subsidiary of Tourmaline Oil Corp. (TSX: TOU), the largest natural gas producer in Canada.

Under the GSA, Tourmaline has agreed to sell 140,000 MMBtu per day of natural gas to Corpus Christi Stage III for a term of 15 years beginning in early 2023. The LNG associated with this gas supply, approximately 0.85 million tonnes per annum ("mtpa"), will be marketed by Cheniere. Cheniere will pay Tourmaline an LNG-linked price for its gas, based on the Platts Japan Korea Marker (JKM), after deductions for fixed LNG shipping costs and a fixed liquefaction fee. Tourmaline Oil Corp. is acting as guarantor of the GSA on behalf of Tourmaline. This Integrated Production Marketing (IPM) transaction is expected to support the development of the Corpus Christi Stage III project.

Dan Tsubouchi @Energy_Tidbits · Jul 14

SAF Group blog "Asian LNG Buyers Abruptly Change and Lock in Long Term Supply – Validates Supply Gap, Provides Support For Brownfield LNG FIDs" just posted. Hope it helps in your #LNG #NatGas #LNGSupplyGap #OOTT perspective. safgroup.ca/insights/trend...

1 1 5

Dan Tsubouchi @Energy_Tidbits · 20h

Reinforces return of full Iran oil is months away. 7th #JCPOA round not until Raisi admin takes over, and no one expects 7th to be last round. Will full Iran #Oil be back before year end? #OOTT

Seyed Abbas Araghchi @araghchi · 22h

Iran government official

We're in a transition period as a democratic transfer of power is underway in our capital.

#Vienna_talks must thus obviously await our new administration. This is what every democracy demands. 1/2

Show this thread

1 2 2

Dan Tsubouchi @Energy_Tidbits · 20h

ICYMI. #DeltaAirlines Q2 call bullish update/outlook on return to air travel. Surge happens as countries reopen. their client survey points to business pickup. Worth a read, below are excerpts from @Bloomberg transcript. #OOTT #OilDemandSurge

Excerpts Delta Air Lines Q2 2021 Earnings Call July 14, 2021
From Bloomberg Transcripts

Items from Mgmt Opening Statement
More encouragingly, the momentum is continuing as we exited June with the demand environment that's accelerating. Domestic leisure demand and yields are above June quarter, 2019 levels and we see clear signs of business in international demand recovery heading into the fall.

We are now in active recovery of our business and the challenges of getting our airline fully back to the service level our customers expect and deserve is daunting in light of the huge surge in demand that we are experiencing

We are starting to see signs of a resurgence of business in international travel both of which are supporting the next leg of the revenue recovery. And we're well positioned to take advantage of both, with leading domestic corporate share and a strong global network.

With 72% of our employees vaccinated, we officially reopened our own offices last month in June, and as I interact with other CEOs, I'm encouraged to hear about their own plans to accelerate their return to office. That sentiment is coming through loud and clear in our most recent corporate survey with almost 95% of our accounts indicating they'll be returning to their offices by the end of this year.

4 8

Dan Tsubouchi @Energy_Tidbits · 21h

finally, @NBCSports shows another @MacHughesGolf shot, drained long birdie on 18 to end -7. don't think they showed any other shot other than drive on 1st. and @coreconn is at -8. imagine if they played together in 3rd last @TheOpen pairing? Go 🇨🇦!

> **Dan Tsubouchi** @Energy_Tidbits · 23h
>
> Looks like @NBCSports sports was forced to show @coreconn with his birdie on 12 now that he is tied for 4th. Still haven't seen @MacHughesGolf hit a shot since his drive on 1 despite him tied for 6th, Go 🇨🇦! twitter.com/Energy_Tidbits...

2 3

Dan Tsubouchi @Energy_Tidbits · Jul 17

#LifeWorks #Deloitte survey 51% senior mgr contemplating resigning, moving to less demanding position, retiring, taking leave of absence & working part time. No doubt Covid stress, but most higher income emerged wealthier so have financial freedom to do so

> Senior leaders' state of wellbeing and resiliency compromising post-pandemic workplace recovery
> lifeworks.com

Dan Tsubouchi @Energy_Tidbits · Jul 17

Hope @NBCSports @TheOpen coverage of 🇨🇦 @MacHughesGolf on 1 & 2 greens isn't indicative or all we will see is him standing watching playing partner @BKoepka hit shots all day. This is starting off like other @NBCSports coverage of majors, do all they can to not show our 🇨🇦 guys.

> **Dan Tsubouchi** @Energy_Tidbits · Jul 17
>
> Fortunately, big push day for Energy Tidbits memo is Saturday. Can have @TheOpen on to watch 🇨🇦 @MacHughesGolf @coreconn. Hopefully some coverage of @MacHughesGolf as he is paired with @BKoepka & just teed off on 1st. Impressive Cdn golfers & increasingly in the hunt at Majors.

1

Dan Tsubouchi @Energy_Tidbits · Jul 16

Air travel surge is coming as countries reopen. #DeltaAirlines Q2 call bullish update on air travel return also said air travel to Mexico now exceeds 2019 levels. Was in #SanJosedelCabo post 4th of July, restaurants saying never been this many tourists in mid July. #OOTT

> Excerpt Bloomberg Transcripts Delta Air Lines Q2 call July 14, 2021
>
> In Q&A, Glen Hauenstein, President replied "*In Latin, it's really the tale of two markets, one is the close-in U.S. point of origin leisure market, as well as Mexico business. Both of these are actually exceeding 2019 levels. So, short whole Latin is doing quite well and we continue to expect that to be very strong as we move into the more traditional leisure season in the late fall.*"

1 1

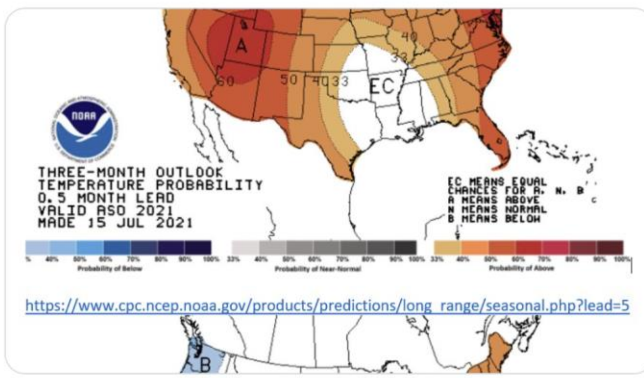
Dan Tsubouchi @Energy_Tidbits · Jul 16

can't help but be reminded to hope the best for all the people being impacted by wildfires in B.C. and Alberta. can smell the smoke in #Canmore coming from B.C. stay safe everyone.

2

Dan Tsubouchi @Energy_Tidbits · Jul 15

Updated #NOAA 3-mth temperature outlook. Forecasts are never perfect but supportive to summer #NatGas prices w/ above average temps to continue in most of US. Negative to winter prices w/ above normal temps in NE & south half of US. cpc.ncep.noaa.gov/products/predi...



1

Dan Tsubouchi @Energy_Tidbits · Jul 15

Low Europe storage + High TTF prices = continued summer support for #HenryHub price and US #LNG exports. Thx @SStapczynski #NatGas

4 4

Dan Tsubouchi @Energy_Tidbits · Jul 15

Did you see big #OilDemand growth forecast in #OPEC July MOMR to end 2022? Passes pre Covid at 101.17 mmb/d in Q3/22 and then jumps up to 102.62 mmb/d in Q4/22, which is +1.83 mmb/d vs Q4/19 of 100.79 mmb/d. #OOTT #Oil

World Oil Demand

World oil demand in 2021 and 2022

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

World oil demand	2020	1Q21	2Q21	3Q21	4Q21	2021	Change 2021/20 Growth	%
Americas	22.56	23.09	24.73	24.84	24.75	24.36	1.80	7.99
of which US	18.44	18.99	20.11	20.34	20.45	19.98	1.54	8.33
Europe	12.43	11.88	12.73	13.61	13.71	12.99	0.56	4.49
Asia Pacific	7.07	7.61	7.17	7.16	7.51	7.36	0.29	4.16
Total OECD	42.06	42.58	44.63	45.61	45.97	44.72	2.65	6.31
China	13.19	12.95	14.27	14.93	15.05	14.30	1.11	8.43
India	4.51	4.94	4.52	4.91	5.61	5.00	0.49	10.82
Other Asia	8.13	8.36	8.93	8.54	8.59	8.61	0.47	5.83
Latin America	6.01	6.15	6.16	6.46	6.40	6.29	0.28	4.68
Middle East	7.55	7.95	7.67	8.24	7.97	7.96	0.42	5.51
Africa	4.08	4.39	3.96	4.16	4.48	4.25	0.16	4.03
Russia	3.37	3.57	3.37	3.57	3.74	3.56	0.19	5.77
Other Eurasia	1.07	1.18	1.19	1.14	1.28	1.20	0.12	11.43
Other Europe	0.65	0.73	0.62	0.68	0.74	0.69	0.05	6.97
Total Non-OECD	48.56	50.23	50.69	52.62	53.85	51.86	3.30	6.79
Total World	90.62	92.80	95.32	98.24	99.82	96.58	5.95	6.57
Previous Estimate	90.62	92.93	95.26	98.18	99.82	96.58	5.95	6.57
Revision	0.00	-0.13	0.06	0.06	0.00	0.00	0.00	0.00

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	24.36	24.33	25.64	25.72	25.55	25.32	0.96	3.92
of which US	19.98	20.05	20.89	21.11	21.17	20.81	0.83	4.16
Europe	12.99	12.38	13.15	14.01	14.04	13.40	0.41	3.17
Asia Pacific	7.36	7.85	7.36	7.29	7.62	7.53	0.17	2.27
Total OECD	44.72	44.55	46.14	47.02	47.21	46.25	1.53	3.43
China	14.30	13.50	14.75	15.32	15.44	14.76	0.45	3.16
India	5.00	5.28	4.75	5.14	5.88	5.26	0.27	5.32
Other Asia	8.61	8.78	9.24	8.82	8.86	8.93	0.32	3.72
Latin America	6.29	6.39	6.34	6.61	6.56	6.48	0.18	2.89
Middle East	7.96	8.29	7.91	8.49	8.20	8.23	0.26	3.32
Africa	4.25	4.57	4.09	4.28	4.61	4.39	0.14	3.29
Russia	3.56	3.67	3.42	3.62	3.79	3.63	0.07	1.83
Other Eurasia	1.20	1.25	1.23	1.17	1.32	1.24	0.05	3.76
Other Europe	0.69	0.75	0.63	0.69	0.76	0.71	0.02	2.38
Total Non-OECD	51.86	52.48	52.37	54.15	55.41	53.61	1.75	3.38
Total World	96.58	97.03	98.52	101.17	102.62	99.86	3.28	3.40

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

World oil demand in 2019 and 2020

3 · 7

Dan Tsubouchi @Energy_Tidbits · Jul 14

#BlackRock CEO Fink raises risk of $100, $125 #Oil, sees rising energy prices if #EnergyTransition keeps pushing to reduce oil supply but govts can't/don't reduce demand. Energy Transition is happening, but will take longer, cost more and be a bumpy ride. Thx @SquawkCNBC #OOTT

SAF Group created transcript of BlackRock CEO Larry Fink on CNBC Squawk Box July 14, 2021

Items in "italics" are SAF Group created transcript

At 6:14am MT, Larry Fink *"And the other thing that I wanted to say and I wrote this and said this in Venice last week, if we don't focus on the demand curve in our energy transition, but only focusing on supply, we are going to see rising energy prices. And I raise the question is what does it mean if we have $100 oil or $120 oil. that's going to be inflationary too."*

Prepared by SAF Group http://www.safgroup.ca/

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Dan Tsubouchi @Energy_Tidbits · Jul 14

Apply #BlackRock Fink general supply chain imbalance thesis to #Electricity. Forcing #Wind #Solar is disruptive, but doesn't fit efficient electricity supply network built on #NatGas etc. Its why increased #EnergyTransition #Electricity costs & supply interruptions are inevitable

SAF Group created transcript of BlackRock CEO Larry Fink on CNBC Squawk Box July 14, 2021

Items in "italics" are SAF Group created transcript

At 6:12am MT, Larry Fink *"that is going to probably lead to systematically more inflation. what we are looking at now with all the issues around the imbalances right now in supply and demand. and with back orders on so many things. I'm hearing from every CEO that they have huge price increases and they're passing them across the board here in the United States and in Europe. And much of it had to do with we had such efficient supply chains, and those supply chains are now showing what I would say the weakness around this imbalance. And then more importantly, moving supply chains away from the concentration in different parts of the world including China. And so all of this is changing our network."*

Prepared by SAF Group http://www.safgroup.ca/

1 · 2

Dan Tsubouchi @Energy_Tidbits · Jul 14

SAF Group blog "Asian LNG Buyers Abruptly Change and Lock in Long Term Supply – Validates Supply Gap, Provides Support For Brownfield LNG FIDs" just posted. Hope it helps in your #LNG #NatGas #LNGSupplyGap #OOTT perspective. safgroup.ca/insights/trend...

SAF GROUP

Blog Summary

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

Posted Wednesday, July 14, 2021 at 10:00 MT

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

7 10

Dan Tsubouchi @Energy_Tidbits · Jul 14

For those not near their laptop. There was a delay in the @EIAgov weekly #Oil #Gasoline #Distillates inventory data as of July 9, didn't come out at 8:30am MT, just out now at 9:30am MT. Prior to release, WTI was $74.58. #OOTT ir.eia.gov/wpsr/overview....

Oil/Products Inventory July 9: EIA, Bloomberg Survey Expectations, API			
(million barrels)	EIA	Expectations	API
Oil	-7.90	-4.00	-4.08
Gasoline	1.00	-2.00	-1.54
Distillates	3.70	1.00	3.70
	-3.20	-5.00	-1.92
Note:In addition, SPR draw of 1.2 mmb for July 9 week			
Note: Cushing had a draw of 1.5 mmb for July 9 week			
Source EIA, Bloomberg			
Prepared by SAF Group			

2

Dan Tsubouchi @Energy_Tidbits · Jul 14

Note @EIAgov weekly #Oil #Gasoline #Distillates inventory data not coming until 9:30am MT #OOTT

Dan Tsubouchi @Energy_Tidbits · Jul 14

note @Amena__Bakr also tweeted that agree to higher uae baseline. #OOTT

> **Amena Bakr** @Amena__Bakr · Jul 14
>
> Great news for Opec Plus and oil markets! The deadlock is over!the expectation now is for the easing of the cuts to take place in addition to extending the pact till the end of 2022 #OOTT #opec

2 2

Dan Tsubouchi @Energy_Tidbits · Jul 14

"the amount of cash sitting on the sidelines has never been greater. the amount of monetary stimulus has never been greater, the amount of fiscal stimulus has never been greater" #BlackRock CEO Fink to @BeckyQuick on @SquawkCNBC right now #OOTT

1 5 5

Dan Tsubouchi @Energy_Tidbits · Jul 13

Positive for #LNG prices. Still waiting on #Woodside word on how corrosion will impact 2021 cargos. but @SStapczynski on trader intel delaying some cargoes from #NorthWestShelfLNG. Key question, does #Woodside have similar corrosion concerns at other 4 trains? #NatGas

production guidance: spokesperson
* Some work at the facility is seen lasting longer than scheduled, said the traders, who requested anonymity to discuss private details
* The Woodside spokesperson declined to comment on any possible additional delay
* NOTE: Woodside planned to shut one LNG train at its Karratha gas plant June 18-July 18, according to its website
** Additional single LNG train shutdowns are scheduled for July 2-9 and July 10-14

To contact the reporter on this story:
Stephen Stapczynski in Singapore at sstapczynsk1@bloomberg.net
To contact the editors responsible for this story:

Dan Tsubouchi @Energy_Tidbits · Jul 9

1/2. Must read. @PeteMilne4 reports #Woodside investigating corrosion on #NorthWestShelfLNG Train 4 (~0.6 bcf/d) "there are concerns the problem could be more widespread". Positive for 2021 #LNG prices and US LNG exports, but if more widespread ...
boilingcold.com.au/concern-over-c...
Show this thread

2 3

Dan Tsubouchi @Energy_Tidbits · Jul 13

#IEA OMR July forecast details. Big thank you to @Bloomberg team for monthly IEA OMR reporting incl details. Thx ksiedenburg@bloomberg.net @VossAvatar @JLeeEnergy gsmith52@bloomberg.net ajordan11@bloomberg.net @RefinedRachel @olyatanas @JWittels @Bill_Lehane #OOTT

China	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1
Other Asia	2.9	2.9	2.9	2.9	3.0	3.0	2.9	3.0	2.9	3.0
Americas	5.7	5.6	5.5	5.5	5.6	5.5	5.3	5.3	5.6	5.4
Middle East	3.2	3.2	3.2	3.2	3.2	3.2	3.2	3.1	3.2	3.2
Africa	1.2	1.2	1.2	1.2	1.3	1.2	1.3	1.3	1.2	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	n/a	30.8	30.4	n/a	n/a
Crude	n/a	n/a	n/a	n/a	n/a	n/a	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 *	28.9	28.6	27.6	27.9	29.0	27.7	25.7	26.5	28.3	27.2

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/QW67PZT0AFB9

3 3

Dan Tsubouchi @Energy_Tidbits · Jul 12

Sea change in Asian #LNG buyers now rushing to secure long term supply. #QatarPetroleum 20-yr deal with #Kogas. Fits view of #LNGSupplyGap emerged w/ delay of 5 bcf/d Mozambique delays. See SAF Apr 28 blog and July 11 Energy Tidbits. #NatGas #OOTT safgroup.ca/insights/trend...

https://www.reuters.com/business/energy/south-korea-signs-20-year-lng-deal-with-qa
July 12, 20213:57 AM MDTLast Updated 22 minutes ago

Energy

South Korea signs 20-year LNG deal with Qatar

Reuters
1 minute read

Qatar is seen in this picture illustration June 5, 2017. REUTERS/Thomas White/I

SEOUL, July 12 (Reuters) - South Korea's energy ministry said c signed a 20-year liquefied natural gas (LNG) supply agreement v next 20 years starting in 2025.

South Korea's state-run Korea Gas Corp (036460.KS) will buy 2 LNG annually from Qatar Petroleum (QATPE.UL).

"This long-term contract is considered to have favourable contrac which would help stabilise LNG supply as well as to significantly ministry said in a statement.

It did not provide financial details of the agreement.

The energy ministry added that KOGAS buys 9 million tonnes of from Qatar through long-term contracts and a contract worth 4.9 LNG is expected to end in 2024.

Reporting by Sangmi Cha, Heekyong Yang; editing by Louise Heavens
Our Standards: The Thomson Reuters Trust Principles.

SAF GROUP

Blog Summary

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 Rovuma 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

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Energy Tidbits

July 11, 2021

Produced by: Dan Tsubouchi

More Signs of LNG Supply Gap Coming – A Sea Change As Asian LNG Buyers Move To Lock Up Long Term Supply

1 4

Dan Tsubouchi @Energy_Tidbits · Jul 11

Usual great lunch at @Flora_Farms. Sat a couple tables over from #NFL @Trevorlawrencee & his wife. you can tell by the way they interact with each other, the staff & a couple of fans that they are impressive young people. how can you not want great success for someone like that?

3

Dan Tsubouchi @Energy_Tidbits · Jul 11

Our weekly SAF July 11, 2021 Energy Tidbits memo was just posted to our SAF Group website. This 40-pg energy research piece expands upon and covers many more items than tweeted this week. See the research section of the SAF website #Oil #OOTT #LNG #NatGas safgroup.ca

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Energy Tidbits

July 11, 2021

Produced by: Dan Tsubouchi

More Signs of LNG Supply Gap Coming – A Sea Change As Asian LNG Buyers Move To Lock Up Long Term Supply

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.

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