Energy Tidbits

July 25, 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

https://rbnenergy.com/danger-zone-the-outlook-for-the-appalachian-natural-gas-market

Danger Zone - The Outlook For The Appalachian Natural Gas Market

Tuesday, 07/20/2021
Published by: Sheetal Nasta

It's been a while since the Appalachian natural gas market has looked this bullish. Outright cash prices at the Eastern Gas South hub are at multi-year highs. Regional storage inventories are sitting low, setting the stage for supply shortages and still higher prices this winter. But the potential for severe takeaway constraints and basis meltdowns are lurking, and by next year, they could become regular features of the market again like they were in the 2016-17 timeframe, or worse — at least in the spring and fall when Northeast demand is lowest. Regional gas production is still being affected by maintenance and has been somewhat volatile lately as a result, but it averaged 34.5 Bcf/d in June, just 300 MMcf/d shy of the December 2020 record. What's more, at current forward curve prices, supply output could surpass previous highs by next spring and grow by ~ 5 Bcf/d (15%) by 2023. Outbound flows set their own record highs this spring, running at over 90% of takeaway capacity, and will head higher, which means that spare exit capacity for supply needing to leave the region is shrinking. The handful of planned takeaway expansions that remain are facing environmental pushback and permitting delays, and the few that are targeting completion in the next year may not be enough. Today, we provide the highlights of the latest forecast from our new NATGAS Appalachia report.

The U.S. Northeast has only been a year-round net gas supply region to the U.S. for about six years now, though it has been sending gas to other regions for longer than that on a seasonal basis. But for much of that time, Appalachian gas production was constrained and growth was wholly dependent on the next takeaway capacity expansion. As such, regional gas producers were vulnerable to severe price discounts whenever production growth outpaced capacity additions, and it wasn't unusual to see outright prices devolve to a fall nadir below $1/MMBtu (dashed-red ovals in Figure 1). That changed in 2018, however. After a slew of expansion projects came online in the 2016-18 timeframe, producers had some running room for the first time in a long while. Capacity was finally outpacing supply leaving the region — as we discussed in our Dog Days Are Over blog series and Drill Down report — and basis (the local price vs. national benchmark Henry Hub) at Eastern Gas South (EGS; formerly Dominion South), Appalachia's gas benchmark hub, strengthened.

Regional gas producers didn't catch much of a break, however. Gas-weighted producers, including in Appalachia, began tightening their belts and pulling back rigs in 2019 in response to overall bearish fundamentals for gas, an extended period of lower gas prices, and shrinking appetite for capital investment. Then came the COVID-19 pandemic and the resulting demand destruction, including LNG export demand. For Appalachian gas producers, that meant still more belt-tightening, laying down more rigs (and shifting the remaining rigs to more efficient, liquids-rich areas), and, as we discussed in Flick of the Switch, low price-driven shut-ins of existing production in the shoulder months to ride out the low pandemic prices. In spite of all that, according to pricing data from our friends at NGI, outright prices at EGS averaged just $1.40/MMBtu last year — the lowest annual average we've seen in the Shale Era for the hub — and they bottomed out at a single-day record low of $0.28/MMBtu on November 9, 2020 (dashed orange oval), back into the "danger zone."

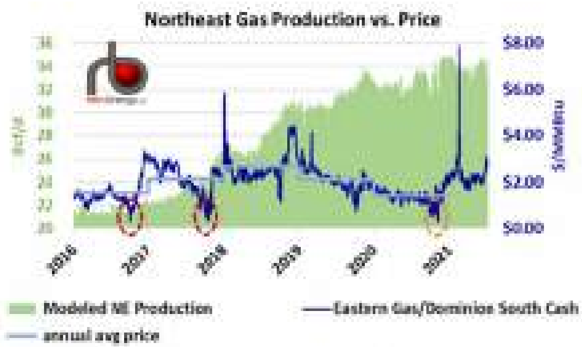


Figure 1. Northeast Gas Production vs. Price. Source: [RBN NATGAS Appalachia](#) (Production), NGI (Cash Price)

Now, well into 2021, we can say their pre-COVID capital discipline and ride-it-out strategy has paid off — outright prices at EGS have rebounded since hitting bottom last November. Year to date, EGS cash prices are averaging about $2.40/MMBtu, ~$1/MMBtu higher than the same period in 2020, and have been at multi-year highs in some months. Additionally, with regional storage levels where they are — well below the five-year average and in the case of Columbia Gas Transmission (TCO), slumping near the five-year low — prices are likely to stay elevated for the most part, especially if we get a warm August followed by an early and extreme winter.

However, there's now a new threat — or rather, an old threat rising anew. Appalachian gas producers are once again trudging toward worsening seasonal takeaway constraints in the coming years, and with that would come seasonal basis meltdowns and, in a worst-case scenario, possibly periodic production shut-ins. In fact, our analysis suggests that Appalachian gas forwards — the solid light-blue line in Figure 2 — are not reflecting the severity of takeaway constraints that are likely to develop in the coming years. By our estimation, basis is likely to look more like the dashed blue line in Figure 2, with sharply lower and deepening discounts in the spring and fall as producers increasingly run out of spare takeaway capacity.

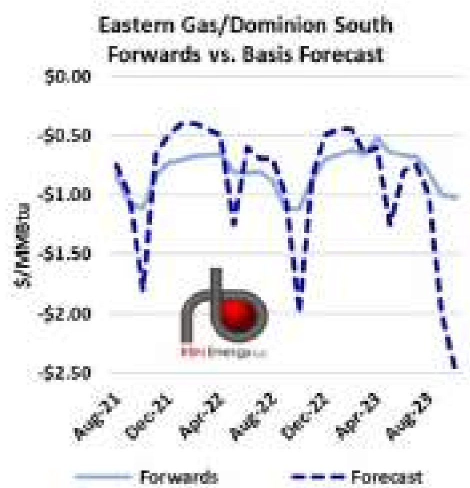


Figure 2. Eastern Gas/Dominion South Basis Forecast vs. Forward Curve. Sources: RBN NATGAS Appalachia (Forecast), Bloomberg (Forwards)

We'll come back to our basis forecast later in the blog. First, let's unpack the fundamentals behind that basis assertion.

Where is the Appalachian Gas Market headed?

Figure 3 summarizes our assessment of the Northeast supply-demand balance over the next two-and-a-half years or so. The graph overlays our supply forecast (navy-blue line) on top of the stacked areas, which include total Northeast exit capacity out of the Appalachia region (green layer), LNG feedgas deliveries (thin orange layer), and high/low Northeast demand scenarios, including the three-year low for each month (dark purple layer) and three-year highs (dark and light purple layers combined).

When the top of the stacked layers exceeds the blue supply line, it indicates that there is sufficient demand and exit capacity available to absorb the supply. However, when the supply line exceeds the top of the stacked layers, it implies there is surplus gas in the region beyond what can be absorbed by in-region consumption and outflows combined and takeaway constraints are likely. After in-region demand is met and outbound capacity is maxed out, there are only two places it can go: into storage or be curtailed.

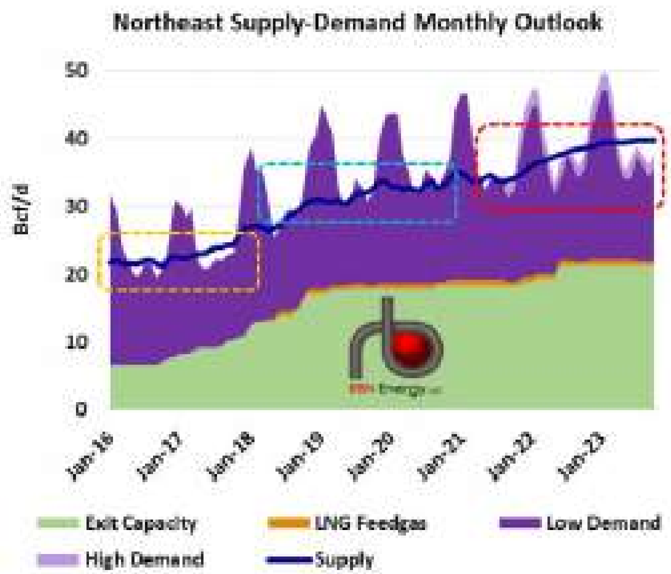


Figure 3. Northeast Supply-Demand Outlook. Source: [RBN NATGAS Appalachia]

As the graph shows, back in 2016-17, supply regularly exceeded demand plus exit capacity, except in the coldest, highest-demand months of the year, leaving more surplus gas in the region (dashed orange box). In the 2018-19 timeframe (dashed blue box), the balance shifted somewhat as more pipeline projects were completed, which increased design capacity out of the region. As a result, outflow constraints eased even in the summer months and EGS basis strengthened to a level more closely resembling transportation costs to downstream markets (as opposed to the deep, constraint-driven discounts we saw prior to that).

However, as the pace of pipeline capacity additions slowed, demand plus exit capacity started falling behind supply again in late 2020, and as that occurred, the risk for severe takeaway constraints increased and EGS basis began reverting to weaker levels. It didn't help that operational issues on Texas Eastern Transmission (TETCO), a major southbound takeaway route, forced it to reduce pressure and capacity on its "30-inch" segment from fall 2019 through much of 2020. (As we discussed at length in our blog It's a Hard Knock Life, capacity was again reduced starting June 1 of this year after a temporary approval from the Pipeline and Hazardous Material Safety Administration, or PHMSA, lapsed).

If the historic relationship of rig and well counts to prices are any indication, these bearish trends are set to deepen in the coming years, as shown in the dashed red box, and look more like they did in 2016-17. In an unconstrained scenario based on the current forward curve, production could climb about 5 Bcf/d (~15%) from the year-to-date 2021 average of ~34 Bcf/d to more than 39 Bcf/d by 2023. (To avoid circular logic between production, takeaway capacity and basis, we assume that production growth in this scenario is unconstrained by pipeline capacity.) Assuming three-year average demand, that would shift the Northeast supply-demand balance from a gas surplus of about 14 Bcf/d in 2020 to an average ~18 Bcf/d in 2022 and ~20 Bcf/d in 2023. If we assume five-year average storage injections/withdrawals (storage activity in the Northeast is ratable — i.e., consistent — after all), that will mean increasing amounts of gas looking to leave the Northeast to downstream markets in the Southeast, Gulf Coast, Midwest or Canada.

Our exit capacity vs. outflow forecast (again, based on unconstrained production) is summarized in Figure 4. We estimate total Northeast exit capacity out of Appalachia (red line) right now is a little over 18 Bcf/d. To be clear, that's design capacity and does not include short-term capacity reductions due to maintenance and other operational disruptions. (Accounting for the TETCO-30 reduction puts operational capacity closer to 17.4 Bcf/d.) There are a couple of projects that would add incremental capacity between now and May 2022: Transco's Leidy South project, which began partial service in November 2020, is due to begin full service by December 2021 adding about 450 MMcf/d of new southbound takeaway capacity on Transco; and Columbia Gas Transmission (CGT) is targeting service for its ~500-MMcf/d Louisiana Xpress (LAXP) expansion in February 2022. Those two would bring total exit capacity to 19.3 Bcf/d. However, the biggest boost in capacity will come from the 2-Bcf/d Mountain Valley Pipeline (MVP) project, which is targeting start-up in summer 2022, which will bring Northeast's Appalachia exit capacity to 21.3 Bcf/d. We assume a June 2022 start for now, but completion depends on state-level permits coming through before winter's end and construction resuming in March 2022 after the winter hiatus (see Slippin' and Slidin').

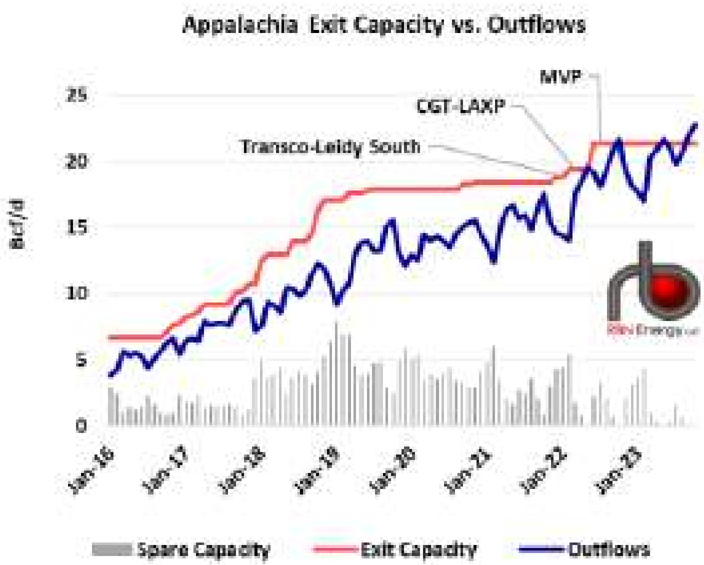


Figure 4. Appalachia Exit Capacity vs. Outflows. Source: RBN NATGAS Appalachia

Note that we don't currently include PennEast in our exit capacity outlook. The project was effectively on hold prior to the favorable Supreme Court ruling in May affirming its ability to use eminent domain to gain access to state-owned land along the pipeline route. However, as we discussed in Movin' On Up, its amended application to the Federal Energy Regulatory Commission (FERC), filed in January 2020, has yet to be approved, and even if federal regulators greenlighted it, there is still the matter of securing other state and local permits in a region where new pipeline development faces staunch environmental opposition.

An incremental 3 Bcf/d or so of exit capacity may seem like a lot. However, as we've seen with previous pipeline additions, that capacity could fill very quickly. The net effect of our supply-demand forecast above is that outbound flows could hit the capacity wall as early as next spring, depending on how the winter goes, and overall spare capacity (gray bars) could dwindle to almost nothing for some months of the year. As we mentioned earlier, flows out of the Northeast from Appalachia (not including exports from New England) were already setting record highs this spring, averaging 16.7 Bcf/d, or more than 90% of total exit capacity, in April and May. Outbound flows during the fall are typically higher as shoulder season brings weaker demand, and storage inventories are peaking at that time.

This year, the low inventory levels mean that available storage capacity will help absorb more of the surplus gas in the fall. However, assuming five-year average injections/withdrawals and three-year average consumption, outflows this October would reach a record 17.5 Bcf/d, or 95% of the 18.4 Bcf/d of total capacity (assuming the TETCO-30 southbound route is operating at its full pressure/capacity by then). At three-year average demand, we wouldn't expect prolonged constraints in the winter months. But by next April, outflows would reach about 18.5 Bcf/d, or over 95% of capacity, and by May, as heating demand wanes, outflows could reach 19.5 Bcf/d, slamming into the capacity wall, which as we said above, would be about 19.3 Bcf/d by then. And by October 2022, supply needing to leave the region would approach 22 Bcf/d. Even if MVP comes online before then, it will only bring exit capacity to 21.3 Bcf/d — not enough to absorb the surplus gas needing to leave the region. Such a scenario would clobber regional basis and outright prices, regardless of what is happening at Henry Hub.

That gets us back to the basis forecast presented in Figure 2. Eastern Gas/Dominion South cash prices are averaging about $2.40/MMBtu this injection season to date, with basis to Henry at minus $0.75/MMBtu, vs. minus $0.34/MMBtu in the same period last year, and that's likely to continue to weaken. While we're less bearish than the forward curve during the winter months, our analysis indicates severe constraint-driven discounts in the spring and fall, particularly May and October. As spare capacity dwindles to near zero next May, EGS basis could fall to minus $1/MMBtu or lower (the current forward curve has it at a discount to Henry of about $0.84/MMBtu). By next October, if the fundamentals we've laid out here persist and Henry Hub stays on the track indicated by the futures curve, EGS basis could reach minus $2.00/MMBtu, and in 2023, all bets are off — we would not be surprised if basis in October sinks to minus $2.50/MMBtu or lower and sub-$0.50/MMBtu outright prices (as seen last fall) return.

There are, of course, lots of moving parts to how the Northeast gas market will unfold. As noted above, regional producers have shown an ability to react to oversupply conditions with short-term shut-ins. An extreme cold winter could deplete storage further vs. prior years and prevent the worst of the constraints next spring, while a warm winter could amplify supply congestion beyond our expectations. Similarly, the prospects and timing of pipeline expansions or capacity disruptions could be make-or-break for regional supply prices and production growth. Appalachian fundamentals have demonstrated time and again that they can turn on a dime and the only way to succeed in that market is to stay up to date with the very latest developments. To address that market, RBN now tracks all this: supply, demand, capacity, basis, storage and more in our newest weekly analysis — the NATGAS Appalachia report.

"Danger Zone" was written by Giorgio Moroder with lyrics by Tom Whitlock. It was the first track on the bestselling soundtrack album for the motion picture, *Top Gun.* Sung by Kenny Loggins and produced by Giorgio Moroder, the song was released as a single in May 1986, and went to #2 on the Billboard Hot 100 Singles chart. Personnel on the record were: Kenny Loggins (vocals, rhythm guitar), Dann Huff (lead guitar), Tom Scott (sax), Giorgio Moroder (synthesizers, sequencer, drum machine), and Tom Whitlock (synthesizer).

The album *Top Gun* was recorded during 1986 at various studios, with different artists and producers. The album's production was overseen by Don Simpson and Jerry Bruckheimer. Kenny Loggins, Cheap Trick, Berlin, Teena Marie, Miami Sound Machine, Loverboy, Larry Greene, Marietta, Harold Faltermeyer, and Steve Stevens were the featured artists on the LP. Released in May 1986, the album went to #1 on the Billboard Top 200 Albums chart and has been certified 9x Platinum by the Recording Industry Association of America. It was the best-selling soundtrack album of 1986. Six singles were released from the LP.

Kenny Loggins is an American singer, songwriter, and guitarist. His early songs were recorded by the Nitty Gritty Dirt band, which led to the founding of the rock duo Loggins and Messina in the ‘70s. The duo released seven studio albums, three live albums, four compilation albums, and 10 charted singles. They have sold more than six million records worldwide. As a solo artist, Loggins has released 14 studio albums, two live albums, two compilation albums, and 31 singles. He is also a member, along with Gary Burr and Georgia Middleman, of the country trio, Blue Sky Riders. The trio has released two studio albums. Loggins continues to record and play an occasional live performance.

Executive summary

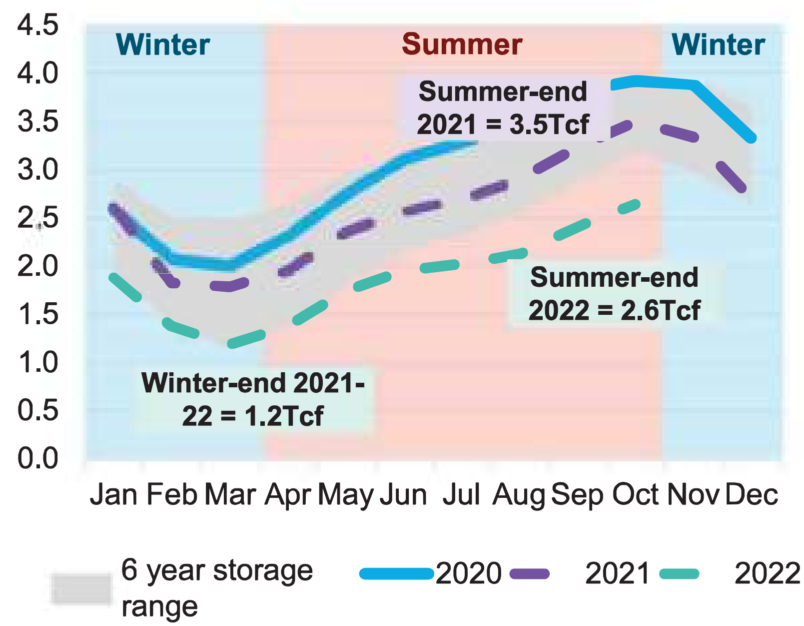
The U.S. gas market is so desperately imbalanced that even near-decadal price highs are not enough to return inventories to 5-year average levels. The situation looks especially bleak because not even mild weather – which has bailed the market out in recent years – is sufficient to rectify the imbalance. Gas shortages can lead to blackouts and freezing homes, as recent events have shown.

- The **market is tight** on a weather-adjusted basis. Only 133Bcf of gas injections are expected in July, 32Bcf lower than a year ago despite much milder weather.
- **LNG cargo** export netbacks have grown despite the run up in domestic gas prices. A combination of tight European balances as well as upcoming seasonally strong north Asian demand tighten the global LNG market. With the first round of maintenances behind us, the path is clear for uninterrupted feedgas demand from all U.S. LNG terminals.
- **Power burns** should fall by 4.7Bcf/d and 3.8Bcf/d year-on-year across July and August. There is room for this to further decrease should prices continue to rise. September and October will be especially sensitive to price gains.
- Gas exports to **Mexico** have grown by almost 2.1Bcf/d since the onset of the pandemic. Further growth will be more gradual and increasingly dependent on the extent to which Mexico moves to a more gas dependent economy.
- **Outlook:** Even if we experience record mild weather between now and summer-end 2022, storage will still finish below 5-year average levels. This means that weather can no longer bail out a tight market, as it has done in recent times.

3.5Tcf	Expected summer-end 2021 storage level
1.2Tcf	Expected winter-end 2021-22 storage level
2.6Tcf	Expected summer-end 2022 storage level

Natural gas inventory forecast, 2021-22

Trillion cubic feet

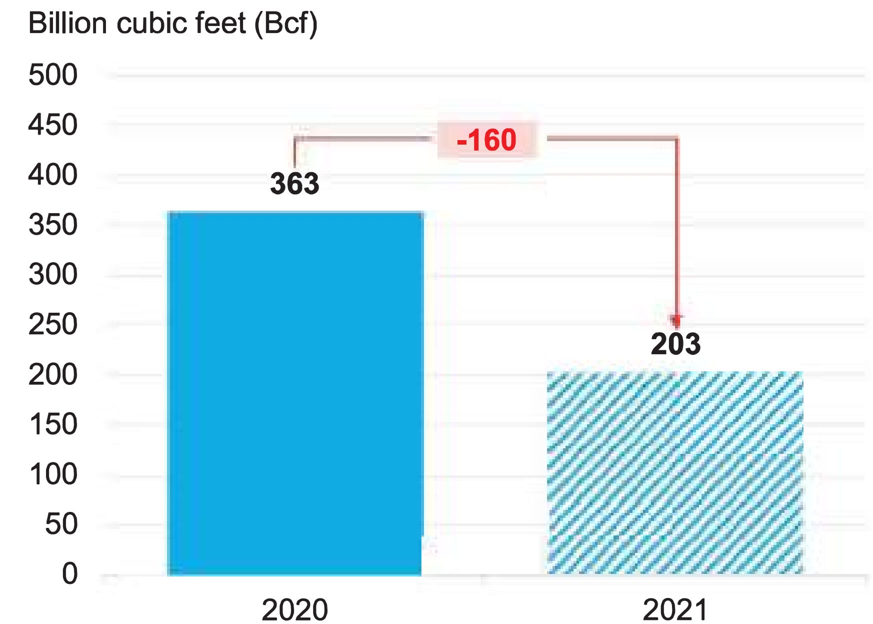


Source: BloombergNEF

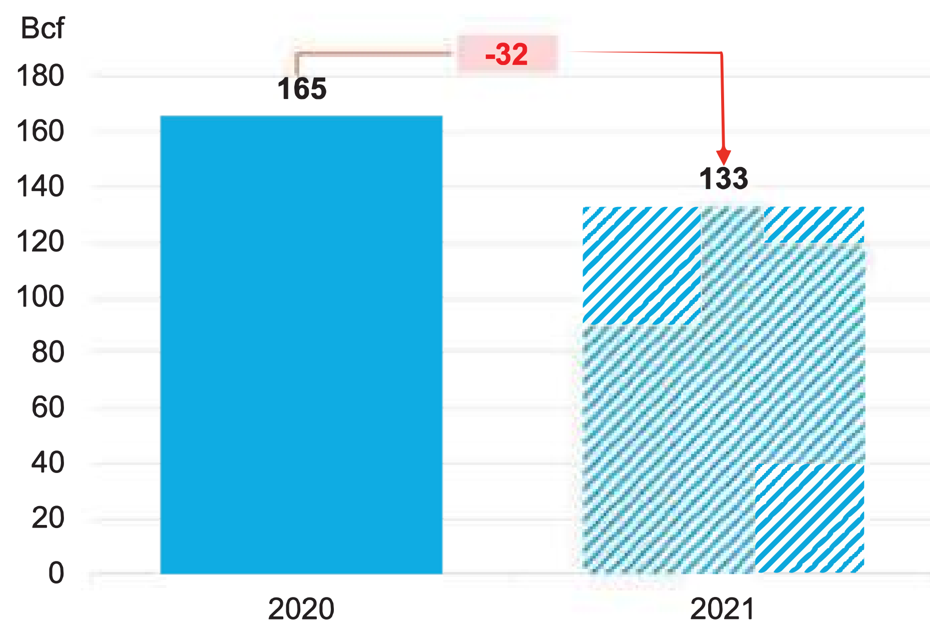
Monthly injection forecasts

Tight injections continue

Injection in June 2020 and 2021



Injection in July 2020 and 2021

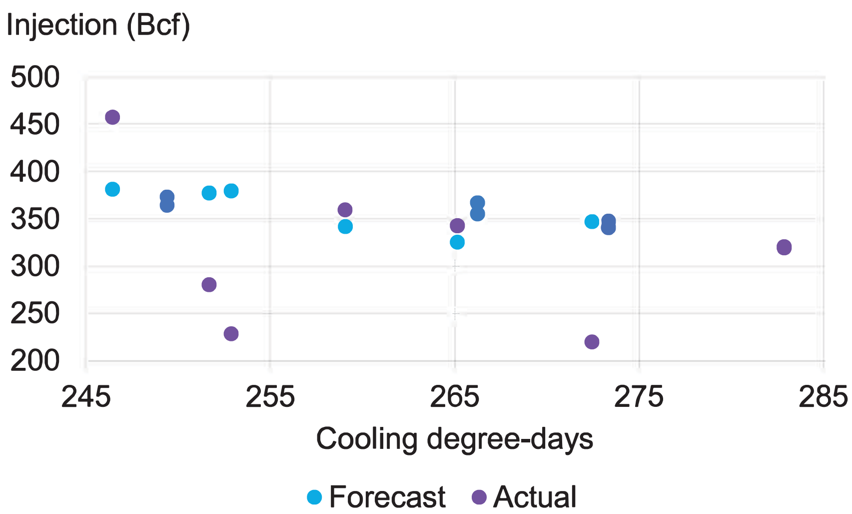


Source: BloombergNEF. Note: Based on forecasts as of July 8, 2021.

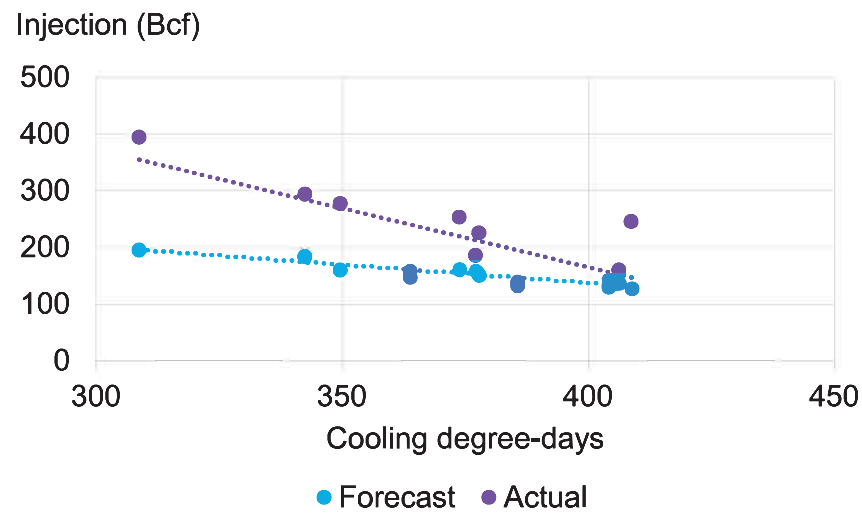
- Storage injections in June 2021 were a massive **160Bcf lower** than for the same month a year earlier. This is the largest year-on-year difference for June in the last 5 years. Supply was **5.4Bcf/d higher** year-on-year, 4.5Bcf/d of which comes from domestic production. Demand **increased by 11Bcf/d**, with LNG demand making up over half of this gain.
- This July will see **32Bcf** less gas injections than a year earlier. Demand outweighs supply **3.9Bcf/d to 2.9Bcf/d.** An incredible **4.7Bcf/d** fall in power burns is trampled by a **7.7Bcf/d** gain in LNG exports. Exports to Mexico also grow by 1.4Bcf/d, year-on-year.

Injections are tight, weather or not

Weather-adjusted injection for June



Weather-adjusted injection for July



How to interpret the charts: BNEF goes through a process to predict total storage injections/withdrawals for a month using weather from the same month in each of the past 10 years. For example, we calculate the total storage withdrawal for January 2021 if it had faced weather from January 2012. This allows us to compare the actual withdrawal in 2012 with that in 2021 using 2012 weather and removes the impact of weather on market conditions and outcomes.

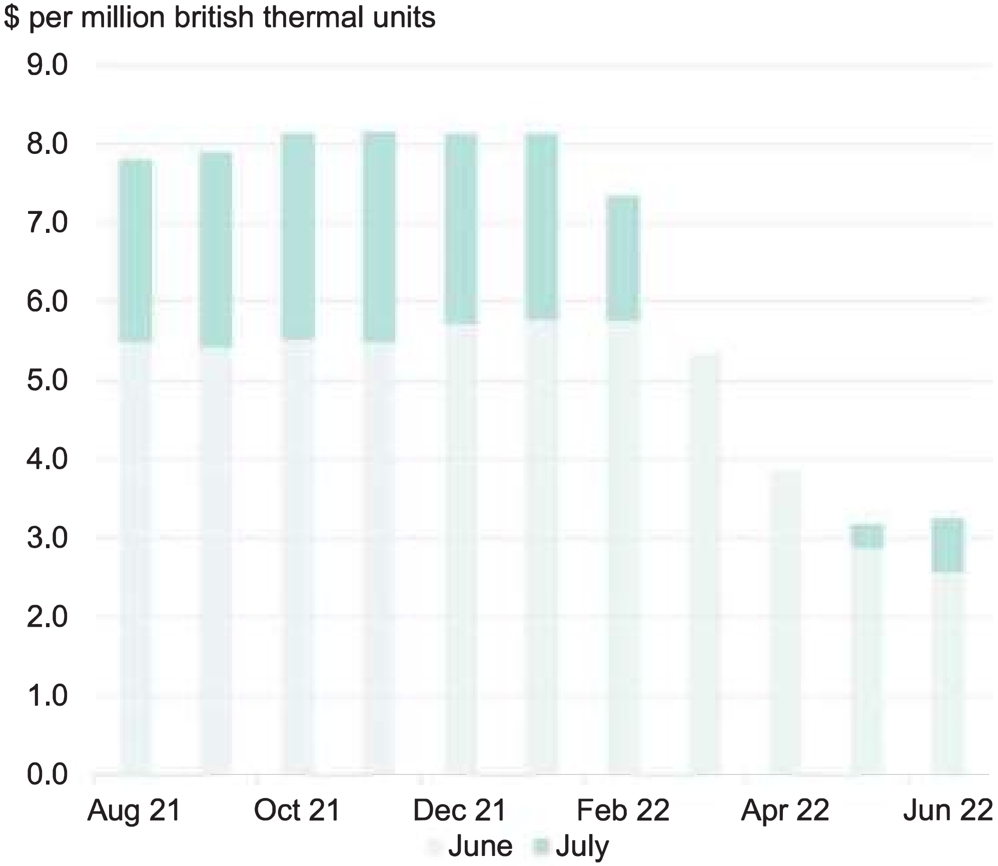
- On a weather-adjusted basis, both June and July are tight. Across both months, the majority of forecast months have smaller injections than what actually occurred.
- By adjusting for weather, we can show that the underlying fundamentals of the market are tight and that the small injections seen so far this summer are caused by more than just hot weather.

Source: BloombergNEF, Weather Services International (WSI).

LNG feedgas should be steady till September

Explore the data: On-site LNG storage tickers

U.S. LNG netback growth between June and July

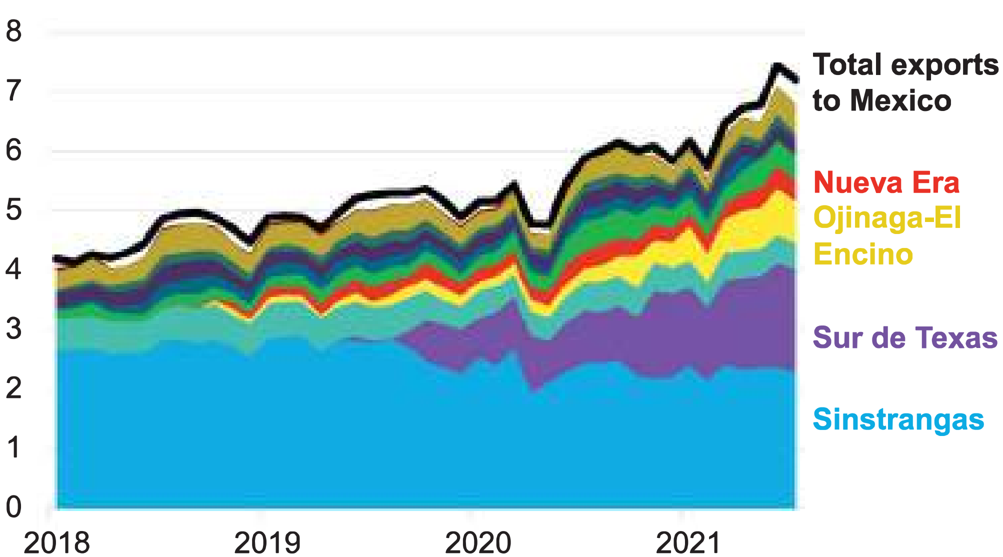


Source: BloombergNEF. Note: Values represents the average netback for delivery to Europe and Asia across two separate days (June 8 and July 8). The x-axis represents the month of cargo delivery.

- Now that the U.S. LNG maintenance season is behind us, the rest of the summer should be smooth sailing for feedgas demand. BNEF's next forecast maintenance events are on Cove Point and Elba Island in September. The remaining trains at Sabine, Freeport and Cameron could also undergo work in October.
- The expected start dates for Calcasieu Pass and Sabine Pass were pushed back from October to December of this year after updates from the developers.
- Netbacks, or the profitability associated with exporting an LNG cargo, increased month-on-month despite the run up in domestic gas prices. Profits rose by around $2/MMBtu through the end of next winter.
- Global gas prices are on the rise due to potentially hot weather in Japan, an uptick in industrial gas demand from China and a tighter European outlook. Europe is expected to finish summer with the lowest storage level in the last 5 years. For more, see: *Europe Gas Monthly: The Crunch Point is Coming*
- The netback increase indicates that the global LNG market is tighter than the domestic gas market. For more see: *Global LNG Monthly: Hotter Asia Pulls European Volumes.*

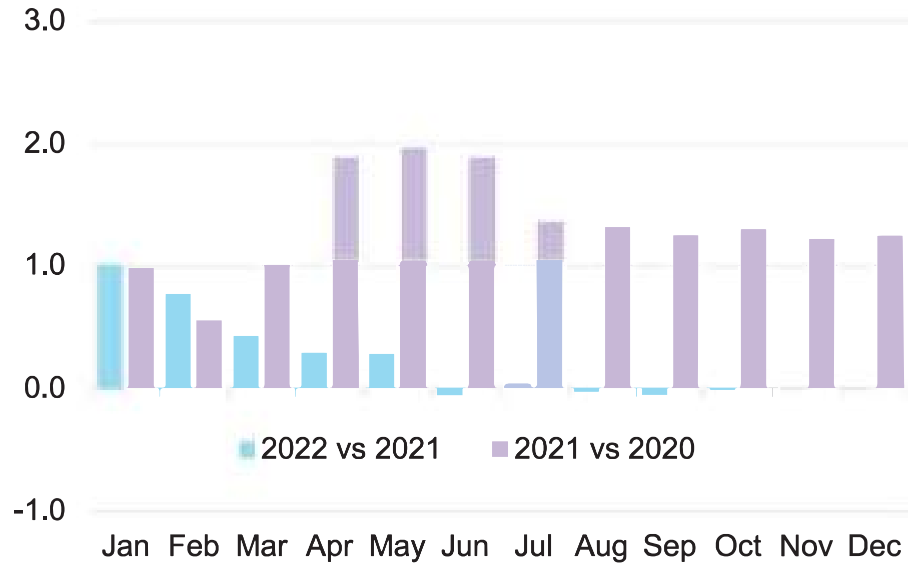
Gas exports to Mexico have grown by 2.1Bcf/d since Q1 2020

Gas exports to Mexico by border pipeline



Source: BloombergNEF

Exports to Mexico, year-over-year



Source: BloombergNEF

- Gas exports to Mexico have been a major source of demand growth since the onset of the pandemic. Mexico received 7.2Bcf/d of gas last month – 2.1Bcf/d greater than flows in Q1 2020. While last month's record-high flows were driven up by hot weather, most of the growth is structural. It was enabled by new cross-border pipelines, namely Sur de Texas, Ojinaga-El Encino, and Nueva Era lines.
- The growth is set to flatten next year as most of the major infrastructure projects are complete. Further growth will be slow and dependent on Mexico's downstream transition to a gas-serviced economy.

Seasonal balances outlook update

Summer 2021 to finish at 3,497Bcf

U.S. L48 gas market supply-and-demand balance sheet

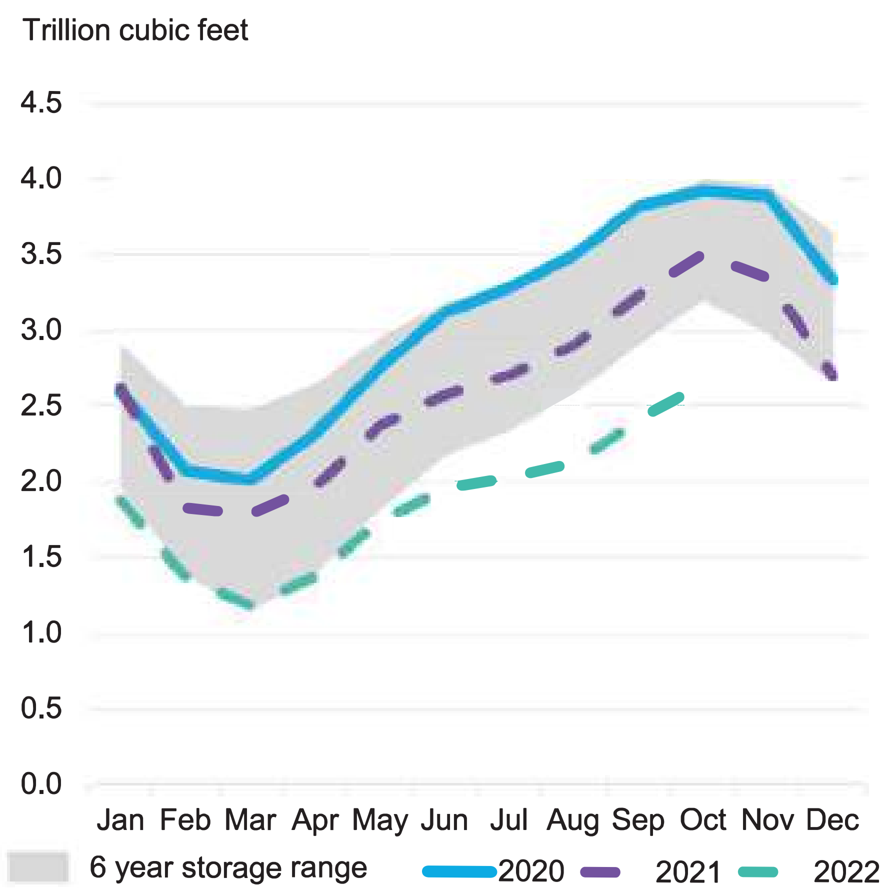
L48 market balance (Bcf/d)	Apr 21	May 21	Jun 21	Jul 21	Aug 21	Sep 21	Oct 21	Nov 21	Dec 21	Jan 22	Feb 22	Mar 22	Apr 22	May 22	Jun 22	Jul 22	Aug 22	Sep 22	Oct 22
Dry production	92.3	91.7	92.2	91.3	92.0	92.4	92.7	93.0	93.2	93.5	93.7	93.9	94.1	94.3	94.5	94.7	94.9	95.1	95.2
Net imports from Canada	4.7	4.5	4.9	5.0	4.9	4.6	4.9	4.6	5.3	6.0	5.6	5.0	4.8	4.9	5.0	5.2	5.1	4.6	4.9
Total supply	**96.9**	**96.2**	**97.1**	**96.3**	**97.0**	**97.0**	**97.7**	**97.6**	**98.5**	**99.4**	**99.3**	**98.9**	**98.8**	**99.2**	**99.5**	**99.9**	**99.9**	**99.7**	**100.2**
Power consumption	25.1	27.0	35.4	39.0	37.1	31.7	28.0	25.0	25.9	25.8	22.7	23.3	24.0	27.4	34.3	39.2	38.6	33.6	28.7
Industrial consumption	21.1	18.7	20.3	19.8	19.9	21.1	22.5	24.2	25.5	25.4	24.8	23.3	22.2	21.7	22.0	22.4	22.2	21.8	22.8
Rescom consumption	19.7	13.3	8.4	7.9	8.1	8.5	14.3	27.6	40.6	46.8	42.6	31.1	19.8	11.8	8.7	7.8	7.8	8.5	14.3
Plant fuel	5.1	5.0	5.1	5.2	5.3	5.3	5.3	5.3	5.3	5.4	5.3	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.5
Pipe losses	2.3	2.1	2.2	2.2	2.2	2.1	2.1	2.6	3.0	3.5	3.3	2.8	2.3	2.1	2.2	2.3	2.3	2.2	2.2
Exports to Mexico	6.5	6.6	7.2	7.0	7.1	7.2	7.1	7.1	6.9	7.0	6.3	6.7	6.8	6.8	7.1	7.1	7.1	7.1	7.1
LNG exports	11.1	10.5	9.9	10.9	10.9	10.2	9.7	10.9	11.9	12.3	12.2	12.3	12.0	12.2	12.8	13.4	13.4	11.4	12.0
Total demand	**90.9**	**83.3**	**88.4**	**92.0**	**90.6**	**86.0**	**89.1**	**102.7**	**119.1**	**126.1**	**117.3**	**104.9**	**92.5**	**87.3**	**92.5**	**97.6**	**96.8**	**90.1**	**92.6**
Balancing item	**-0.2**	**-0.1**	**2.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**
Average daily storage change last year	10.2	14.0	12.1	5.3	6.9	10.8	3.3	-1.1	-18.0	-23.0	-28.3	-1.3	6.2	12.9	6.8	4.3	6.4	11.0	8.6
Average daily storage change	6.2	12.9	6.8	4.3	6.4	11.0	8.6	-5.1	-20.7	-26.7	-18.0	-6.1	6.4	11.9	7.0	2.3	3.1	9.6	7.5
Total monthly storage change	187	401	203	133	197	329	266	-154	-640	-827	-504	-188	191	368	209	71	97	288	234
Storage level (Bcf)	**1,968**	**2,369**	**2,572**	**2,705**	**2,902**	**3,231**	[illegible]	**3,343**	**2,703**	**1,875**	**1,371**	**1,183**	**1,375**	**1,743**	**1,951**	**2,022**	**2,119**	**2,406**	**2,640**

Source: BloombergNEF. Note: Based on forward curve as of July 8, 2021. Green indicates tightness, the market is either withdrawing more or injecting less than for the same month a year prior.

Market tight despite price run-up

Read previous monthly: U.S. gas monthly: When Wrongs Make a Right

Natural gas inventory forecast, 2021-22



Source: BloombergNEF

Inventories are set for severe tightness over the next 18 months despite the run-up in prices this month. Lower burns and higher production is not enough to balance out demand gains in other sectors. These effects combine to deplete inventories.

Summer 2021

BNEF's **3,497Bcf** end-of-summer inventory view is **140Bcf** lower than last months forecast. A combination of stronger exports to Mexico and industrial demand lowers our outlook.

Winter 2021-22

The winter-end estimate falls to **1,183Bcf.** This is mostly just a continuation of the deficit from summer 2021 rather than winter fundamentals.

Summer 2022

Next summer ends with **2,640Bcf**, which is only **77Bcf** lower than last month's report. We revised up our production outlook, which helped decrease the previously mentioned forecast-on-forecast deficit from 140Bcf.

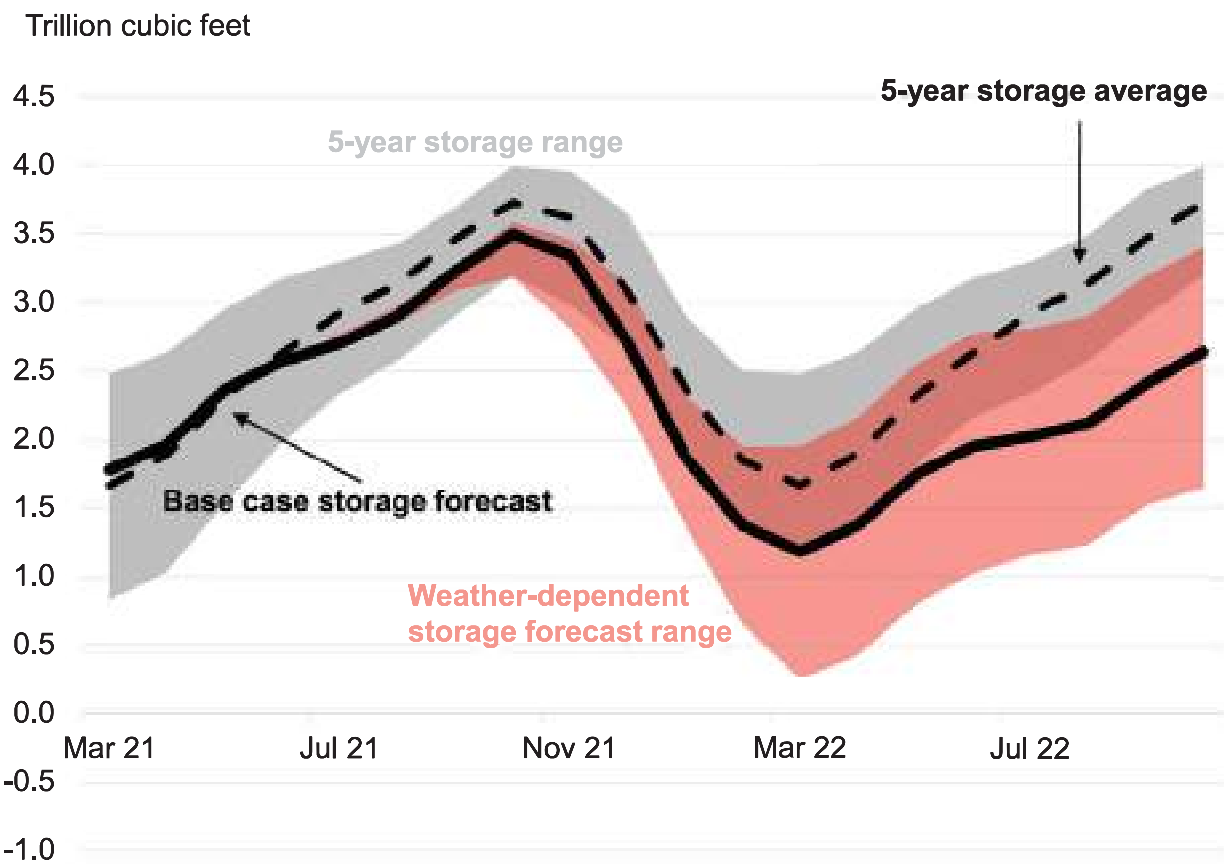
Year-on-year changes in major fundamental sectors

Sector	Summer 2021 (Bcf/d)	Winter 2021-22(Bcf/d)	Summer 2022 (Bcf/d)
Production	2.9	3.2	2.6
Power burns	-2.0	-2.2	0.4
ResCom	-0.2	0.7	-0.2
Industrial	-0.3	2.1	1.7
LNG	4.9	1.9	2.0

Storage will almost certainly finish below 5-year average levels

Read previous monthly:
U.S. gas monthly: When Wrongs Make a Right

Weather-dependent gas storage forecast range versus 5-year historical storage levels



Source: BloombergNEF. Note: Weather modeling only varies Canadian imports, heating (ResCom) demand, industrial consumption and power burns. Other sectors are static.

- This chart compares the five-year historical storage range (gray) with the weather variability (red translucent) of the base-case storage forecast. Weather variability is calculated by running the storage model under weather scenarios from 2010-2020.
- From here on out, weather will not be enough to move balances back in line with 5-year average levels. Even a near-record mild remainder of the summer (as seen in 2017) only guarantees 3.6Tcf by summer-end.
- This argument can be extended to the end of summer next year. The mildest period of the last 10 years (2011-2012) inflates storage to just 3.4Tcf by summer-end 2022.

https://www.bloomberg.com/news/articles/2021-07-19/chevron-s-carbon-capture-struggle-shows-big-oil-s-climate-hurdle?sref=DLVyDcXJ

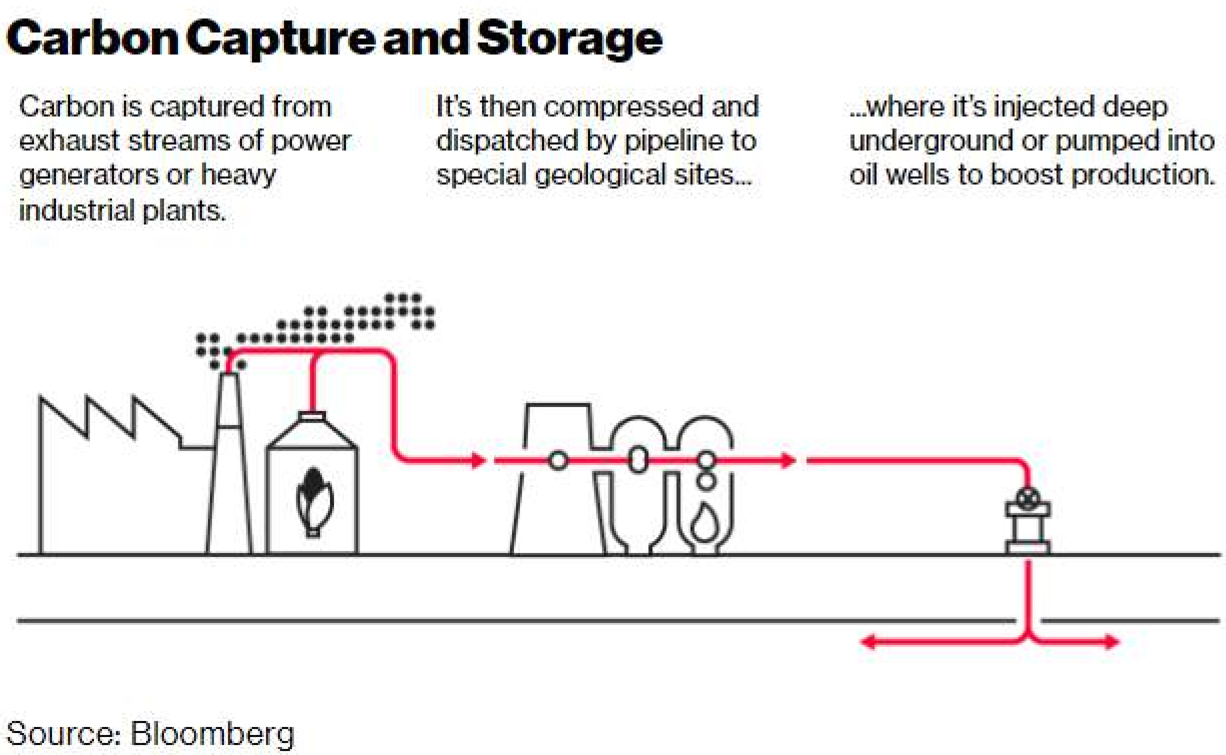
Chevron's Carbon Capture Struggle Shows Big Oil's Climate Hurdle

By Stephen Stapczynski
July 18, 2021, 9:51 PM MDT

- World's biggest CCS project has missed regulatory benchmark
- Energy industry staking net-zero future on the technology

The world's biggest project to capture and store carbon dioxide isn't working like it should, highlighting the challenges oil companies face in tackling their greenhouse gas emissions.

Chevron Corp.'s system at the $54 billion Gorgon liquefied natural gas export plant in Australia missed a local government target to inject captured carbon dioxide underground, the San Ramon, California-based company said Monday. That's a setback for energy companies globally that have staked their net-zero futures on the technology, which has shown limited success to date.



While Chevron has sequestered almost 5 million tons of carbon dioxide since the capture project began in August 2019, that's fallen short of a target to capture an average 80% of emissions in the first five years of the LNG facility's operation.

"Chevron is working with the Western Australia regulator on making up the shortfall," the company's Australia Managing Director Mark Hatfield said in a statement.

The company has buried only 30% of about 15 million tons of CO_2 generated since Gorgon began producing gas in March 2016, oil industry publication Boiling Cold reported Friday.

Oil and natural gas producers are counting on carbon capture, or CCS, to succeed as they come under greater scrutiny from investors and governments to lower emissions. To limit global warming, about 10,000 large CCS facilities need to be built over the next five decades, according to Royal Dutch Shell Plc. There were fewer than 50 in operation last year.

Shell and ExxonMobil Corp. each hold 25% of Gorgon LNG, while Chevron has just over 47%.

Gorgon's multibillion-dollar CCS project has been beset with technical issues, including problems with its pressure management system, according to Boiling Cold.

Instead of venting the CO_2 into the atmosphere, which is the industry norm, Chevron's plant is designed to manage pollution that's produced from the offshore fields that feed the LNG facility. As the gas is sent to be liquefied for export, the CO_2 is pumped into a reservoir more than 2 kilometers (1.2 miles) underground.

Western Australia's government insisted on the CCS facility as a condition for approving Gorgon, which is expected to run for four decades. The state's regulator has requested details on why Chevron missed its target, and Western Australia's Environment Minister Amber-Jade Sanderson is seeking a meeting with the company.

"Gorgon's failure poses a major problem for any oil and gas company betting on CCS to meet net zero," said Ian Porter, the chairperson of Sustainable Energy Now, WA. "CCS simply does not work at the scale and at the price needed."

— With assistance by James Thornhill

https://australia.chevron.com/news/2021/co2-injection-milestone

chevron australia CO_2 injection milestone

PERTH, Western Australia, 19 July 2021 – Chevron Australia is poised to reach a significant milestone at its Gorgon LNG facility, injecting five million tonnes of greenhouse gas (carbon dioxide equivalent, CO_2e) since safely starting the system in August 2019.

The milestone represents the largest volume of injection achieved within this time frame by any environmental carbon capture and storage (CCS) system of comparable specifications.

Injecting five million tonnes of CO_2e is equivalent to taking more than 1.6 million passenger vehicles off Australia's roads for a year[1].

“This significant milestone shows how we're deploying technology, innovation and skills to deliver cleaner energy and reduce our carbon footprint,” Chevron Australia managing director Mark Hatfield said.

“The Gorgon carbon capture and storage (CCS) system is the biggest CCS system designed to capture carbon emissions and is demonstrating Australia's world-leading capability in the area.”

Once fully operational, the system will capture up to 4 million tonnes of CO_2 annually and reduce greenhouse gas emissions by more than 100 million tonnes over the life of the injection project.

The system works by taking naturally occurring CO_2 from offshore gas reservoirs and injecting it in a giant sandstone formation two kilometres under Barrow Island, where it remains trapped.

It prevents millions of tonnes of greenhouse gases being vented into the atmosphere.

Hatfield said while the system had delivered significant reductions in Gorgon’s emissions, the time taken to safely start the system meant Chevron had not met injection requirements.

"Chevron is working with the WA regulator on making up the shortfall and will report publicly on that later in the year," Hatfield said.

“Like any pioneering endeavour, it takes time to optimise a new system to ensure it performs reliably over 40-plus years of operation.

“The road hasn’t always been smooth, but the challenges we’ve faced – and overcome – make it easier for those who aspire to reduce their emissions through CCS.

“We’re committed to sharing the lessons we’ve learned with state and federal governments, research institutes and other energy producers to assist the deployment of CCS in Australia.

“CCS is a proven technology which experts agree is critical to achieving a lower carbon future while ensuring access to affordable and reliable energy for billions around the world who rely on it.”

The Chevron-operated Gorgon Project is a joint venture between the Australian subsidiaries of Chevron (47.333 percent), ExxonMobil (25 percent), Shell (25 percent), Osaka Gas (1.25 percent), Tokyo Gas (1 percent) and JERA (0.417 percent).

Chevron is one of the world's leading integrated energy companies and through its Australian subsidiaries, has been present in Australia for more than 60 years. With the ingenuity and commitment of thousands of workers, Chevron Australia operates the Gorgon and Wheatstone natural gas facilities; manages its equal one-sixth interest in the North West Shelf Venture; operates Australia’s largest onshore oilfield on Barrow Island; is a significant investor in exploration; and via Puma Energy delivers quality fuel products and services across Australia, operating or supplying a network of more than 360 retail locations and an extensive 24-hour hour diesel stop network, as well as 14 depots and three seaboard terminals.

[1] Based on estimation light vehicles (cars, 4x4s, SUVs and small commercial vehicles up to 3.5 tonnes) emit 3 tonnes of greenhouse gases a year. [Department of Industry, Science, Energy and Resources.]

https://m.koreatimes.co.kr/pages/article.amp.asp?newsIdx=312403

The Korea Times
July. 19. 2021

Biz & Tech2021-07-19 16:41

LNG power generation poses dilemma for Korea's energy policy

·

By Kim Bo-eun

The Moon Jae-in administration has been moving toward phasing out coal-fired power generation and nuclear power plants.

As the transition takes place to renewable energy, the government has made liquefied natural gas (LNG) an important source of power generation.

The government is backing LNG because it is more environmentally friendly, with lower levels of carbon emission compared to other energy sources. LNG is known to emit around half of the greenhouse gases that coal does when burnt to generate electricity.

LNG became the largest source of power generation for the country in April this year. The government has unveiled plans to expand the scale of LNG power generation to 59,096 megawatts by 2034. This is up from 39,655 megawatts in 2019. If the planned transition takes place, LNG will become the second-largest source of power generation in that year, accounting for 30.6 percent, after renewable energy which will take up 40.3 percent.

The plan is to bring down the proportion of coal-fired plants in total power generation to 15 percent in 2034 from 29.5 percent in 2019 and reduce the share taken up by nuclear plants to 10.1 percent from 18.5 percent.

The government plans to construct 19 more LNG power plants by 2030 to enable the transition.

But the high cost of LNG fuel is posing a dilemma — it is more than 10 times higher than that of operating nuclear plants.

Another risk is that Korea relies on LNG imports from the U.S. and Middle Eastern countries such as Quatar and Oman. The Ministry of Trade, Industry and Energy is rushing to secure long-term supply contracts to meet growing demand due to the expanded use of LNG. Demand is projected to grow to 4,797 tons by 2034, up from 4,169 tons this year, according to the ministry's plan. This presents a challenge, as Korea will have to secure additional contracts with other countries.

The dependency on imports poses risks, because a failure to secure long-term contracts will force the government to rely on short-term contracts, which would likely bring up costs further, and potentially lead to a rise in electricity bills

Kim Bo-eun bkim@koreatimes.co.kr

Highlights for the month

- The consumption of petroleum products during April-June 2021 with a volume of 48.5 MMT reported a growth of 18.8% compared to the volume of 40.8 MMT during the same period of the previous year. Except SKO all other petroleum products reported a growth in consumption during April-June 2021 compared to the same period of the previous year. The consumption of petroleum products during June 2021 recorded a growth of 1.5% compared to the same period of the previous year.
- Ethanol blending with Petrol was 9.1% during June 2021 and cumulative during December 2020- June 2021 was 7.9%.
- Total consumption of natural gas (including internal consumption) for the month of June 2021 was 5030 MMSCM which was 0.4% lower than the corresponding month of the previous year. The cumulative consumption of 15515 MMSCM for the current year till June 2021 was higher by 14.7% compared with the corresponding period of the previous year.
- Indigenous crude oil and condensate production during June 2021 was lower by 1.8 % than that of June 2020 as compared to a de-growth of 6.3% during May 2021. OIL registered a growth of 2.0 % and ONGC registered a de-growth of 2.7 % during June 2021 as compared to June 2020. PSC registered de-growth of 0.7 % during June 2021 as compared to June 2020. De-growth of 3.4 % was registered in the total crude oil and condensate production during April- June 2021 over the corresponding period of the previous year.
- Crude oil processed during June 2021 was 18.4 MMT, which was 4.9 % higher than June 2020 as compared to a growth of 16.0 % during May 2021. Growth of 17.7 % was registered in the total crude oil processing during April- June 2021 over the corresponding period of the previous year.
- Production of petroleum products saw a growth of 2.4 % during June 2021 over June 2020 as compared to a growth of 15.5 % during May 2021. Growth of 15.4 % was registered in the total POL production during April- June 2021 over the corresponding period of the previous year.

•	Gross production of natural gas for the month of June 2021 was 2777 MMSCM which was higher by 19.5% compared with the corresponding month of the previous year. The cumulative gross production of natural gas of 8169 MMSCM for the current financial year till June, 2021 was higher by 20.4% compared with the corresponding period of the previous year.
•	Crude oil imports increased by 16.5% and 14.7% during June 2021 and April-June 2021 respectively as compared to the corresponding period of the previous year.
•	POL products imports increased by 6.2% and decreased by 2.1% during June 2021 and April-June 2021 respectively as compared to the corresponding period of the previous year. Decrease in POL products imports during April-June 2021 was due to decrease in imports of petcoke, liquified petroleum gas (LPG), high speed diesel (HSD) and aviation turbine fuel (ATF).
•	LNG import for the month of June, 2021(P) was 2316 MMSCM which was 17.3% lower than the corresponding month of the previous year. The cumulative import of 7558 MMSCM for the current year till June, 2021 was higher by 8% compared with the corresponding period of the previous year.
•	Exports of POL products increased by 15% and decreased by 9.1% during June 2021 and April-June 2021 respectively as compared to the corresponding period of the previous year. Decrease in POL products exports during April-June 2021 (P) was due to decrease in exports of high speed diesel (HSD), petcoke/CBFS, naphtha, fuel oil (FO) and LOBS/Lube oil.
•	The price of Brent Crude averaged \$73.04/bbl during June, 2021 as against \$68.75/bbl during May 2021 and \$40.07/bbl during June 2020. The Indian basket crude price averaged \$71.98/bbl during June 2021 as against \$66.95/bbl during May 2021 and \$40.63 /bbl during June 2020.

2. Crude oil, LNG and petroleum products at a glance

	Details	Unit/ Base	2019-20	2020-21 (P)	June		April-June	
					2020-21 (P)	2021-22 (P)	2020-21 (P)	2021-22 (P)
1	Crude oil production in India#	MMT	32.2	30.5	2.5	2.5	7.7	7.4
2	Consumption of petroleum products*	MMT	214.1	194.6	16.1	16.3	40.8	48.5
3	Production of petroleum products	MMT	262.9	233.4	18.7	19.2	52.0	60.0
4	Gross natural gas production	MMSCM	31,184	28,672	2,324	2,777	6,785	8,169
5	Natural gas consumption	MMSCM	64,144	60,646	5,050	5,030	13,530	15,515
6	Imports & exports^:							
	Crude oil imports	MMT	227.0	198.1	13.7	15.9	44.8	51.4
		$ Billion	101.4	62.7	3.2	7.9	8.5	24.7
	Petroleum products (POL) imports*	MMT	43.8	43.5	3.4	3.6	10.5	10.3
		$ Billion	17.7	14.2	0.9	1.4	2.6	3.9
	Gross petroleum imports (Crude + POL)	MMT	270.7	241.6	17.1	19.5	55.3	61.7
		$ Billion	119.1	76.9	4.2	9.3	11.1	28.6
	Petroleum products (POL) export	MMT	65.7	56.8	4.4	5.1	16.2	14.7
		$ Billion	35.8	21.4	1.4	3.0	3.9	8.5
	LNG imports*	MMSCM	33,887	32,861	2,800	2,316	6,998	7,558
		$ Billion	9.5	7.4	0.5	0.7	1.4	2.2
7	Petroleum imports as percentage of India's gross imports (in value terms)	%	25.1	19.5	19.7	22.3	18.4	22.7
8	Petroleum exports as percentage of India's gross exports (in value terms)	%	11.4	7.3	6.6	9.1	7.6	8.9
9	Import dependency of crude (on consumption basis)	%	85.0	84.4	83.0	86.3	81.6	85.7

#Includes condensate; *Jul 2020- June 2021 DGCIS data prorated; ^RIL data prorated

3. Indigenous crude oil production (Million Metric Tonnes)

Details	2019-20	2020-21 (P)	June			April-June		
			2020-21 (P)	2021-22 Target*	2021-22 (P)	2020-21 (P)	2021-22 Target*	2021-22 (P)
ONGC	19.2	19.1	1.6	1.7	1.5	4.8	5.0	4.6
Oil India Limited (OIL)	3.1	2.9	0.2	0.2	0.2	0.7	0.8	0.7
Private / Joint Ventures (JVs)	8.2	7.1	0.6	0.6	0.6	1.8	1.9	1.8
Total Crude Oil	**30.5**	**29.1**	**2.4**	**2.5**	**2.4**	**7.3**	**7.6**	**7.1**
ONGC condensate	1.4	1.1	0.1		0.1	0.3		0.2
PSC condensate	0.3	0.3	0.02		0.03	0.05		0.08
Total condensate	**1.6**	**1.4**	**0.1**		**0.1**	**0.3**		**0.3**
Total (Crude + Condensate) (MMT)	**32.2**	**30.5**	**2.5**	**2.5**	**2.5**	**7.7**	**7.6**	**7.4**
Total (Crude + Condensate) (Million Bbl/Day)	0.64	0.61	0.62		0.61	0.62		0.60

*Provisional targets inclusive of condensate.

4. Domestic oil & gas production vis-à-vis overseas production

Details	2019-20	2020-21 (P)	June		April-June	
			2020-21 (P)	2021-22 (P)	2020-21 (P)	2021-22 (P)
Total domestic production (MMTOE)	63.4	59.2	4.9	5.3	14.5	15.6
Overseas production (MMTOE)	24.5	21.9	1.8	1.8	5.6	5.4
Overseas production as percentage of domestic production	**38.7%**	**37.0%**	**37.0%**	**33.8%**	**39.0%**	**34.9%**

Source: ONGC Videsh, GAIL, OIL , IOCL, HPCL & BPRL

5. High Sulphur (HS) & Low Sulphur (LS) crude oil processing (MMT)

Details		2019-20	2020-21 (P)	June		April-June	
				2020-21 (P)	2021-22 (P)	2020-21 (P)	2021-22 (P)
1	High Sulphur crude	192.4	161.3	12.7	13.8	35.5	42.8
2	Low Sulphur crude	62.0	60.5	4.8	4.6	13.2	14.4
Total crude processed (MMT)		**254.4**	**221.8**	**17.5**	**18.4**	**48.6**	**57.3**
Total crude processed (Million Bbl/Day)		5.09	4.45	4.28	4.50	3.92	4.61
Percentage share of HS crude in total crude oil processing		**75.6%**	**72.7%**	**72.4%**	**75.0%**	**72.9%**	**74.8%**

6. Quantity and value of crude oil imports			
Year	Quantity (MMT)	$ Million	Rs. Crore
2019-20	227.0	1,01,376	7,17,001
2020-21 (P)	198.1	62,711	4,62,996

7. Self-sufficiency in petroleum products (Million Metric Tonnes)							
Particulars		2019-20	2020-21 (P)	June		April-June	
				2020-21 (P)	2021-22 (P)	2020-21 (P)	2021-22 (P)
1	Indigenous crude oil processing	29.3	28.0	2.5	2.1	7.0	6.3
2	Products from indigenous crude (93.3% of crude oil processed)	27.3	26.1	2.4	1.9	6.5	5.9
3	Products from fractionators (Including LPG and Gas)	4.8	4.2	0.4	0.3	1.0	1.0
4	Total production from indigenous crude & condensate **(2 + 3)**	32.1	30.3	2.7	2.2	7.5	6.9
5	Total domestic consumption	214.1	194.6	16.1	16.3	40.8	48.5
% Self-sufficiency (4 / 5)		**15.0%**	**15.6%**	**17.0%**	**13.7%**	**18.4%**	**14.3%**

8. Refineries: Installed capacity and crude oil processing (MMTPA / MMT)

Company	Refinery	Installed capacity (1.7.2021) MMTPA	Crude oil processing (MMT)							
			2019-20	2020-21 (P)	June			April-June		
					2020-21 (P)	2021-22 (Target)	2021-22 (P)	2020-21 (P)	2021-22 (Target)	2021-22 (P)
IOCL	Barauni (1964)	6.0	6.5	5.5	0.5	0.3	0.4	1.1	1.4	1.4
	Koyali (1965)	13.7	13.1	11.6	1.0	1.2	1.1	2.4	3.6	3.1
	Haldia (1975)	8.0	6.5	6.8	0.5	0.7	0.6	1.2	2.1	1.9
	Mathura (1982)	8.0	8.9	8.9	0.8	0.7	0.7	2.0	2.3	2.2
	Panipat (1998)	15.0	15.0	13.2	1.2	1.3	1.2	2.5	3.9	3.7
	Guwahati (1962)	1.0	0.9	0.8	0.06	0.0	0.0	0.09	0.0	0.1
	Digboi (1901)	0.65	0.7	0.6	0.06	0.06	0.06	0.2	0.2	0.2
	Bongaigaon(1979)	2.35	2.0	2.5	0.2	0.2	0.2	0.6	0.6	0.7
	Paradip (2016)	15.0	15.8	12.5	1.2	1.3	1.0	2.9	3.9	3.4
	IOCL-TOTAL	**69.7**	**69.4**	**62.4**	**5.6**	**5.8**	**5.4**	**12.9**	**18.1**	**16.7**
CPCL	Manali (1969)	10.5	10.2	8.2	0.6	0.9	0.6	1.3	1.9	2.0
	CBR (1993)	1.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	CPCL-TOTAL	**11.5**	**10.2**	**8.2**	**0.6**	**0.9**	**0.6**	**1.3**	**1.9**	**2.0**
BPCL	Mumbai (1955)	12.0	15.0	12.9	1.0	1.2	1.0	2.6	3.6	3.4
	Kochi (1966)	15.5	16.5	13.3	0.9	1.4	1.0	2.4	4.3	3.3
BORL	Bina (2011)	7.8	7.9	6.2	0.4	0.4	0.4	1.2	1.7	1.6
NRL	Numaligarh (1999)	3.0	2.4	2.7	0.2	0.2	0.2	0.6	0.6	0.6
	BPCL-TOTAL	**38.3**	**41.8**	**35.1**	**2.5**	**3.3**	**2.7**	**6.9**	**10.2**	**8.9**

Company	Refinery	Installed capacity (1.7.2021) (MMTPA)	Crude oil processing (MMT)							
			2019-20	2020-21 (P)	June			Apr-June		
					2020-21 (P)	2021-22 (Target)	2021-22 (P)	2020-21 (P)	2021-22 (Target)	2021-22 (P)
ONGC	Tatipaka (2001)	0.066	0.087	0.081	0.007	0.005	0.006	0.016	0.014	0.020
MRPL	Mangalore (1996)	15.0	14.0	11.5	0.6	1.2	1.0	1.9	3.2	3.1
	ONGC-TOTAL	**15.1**	**14.0**	**11.6**	**0.6**	**1.2**	**1.0**	**1.9**	**3.2**	**3.1**
HPCL	Mumbai (1954)	7.5	8.1	7.4	0.7	0.3	0.3	1.7	0.6	0.5
	Visakh (1957)	8.3	9.1	9.1	0.7	0.8	0.5	2.2	2.4	2.0
HMEL	Bathinda (2012)	11.3	12.2	10.1	0.8	0.9	1.1	2.0	2.7	3.2
	HPCL- TOTAL	**27.1**	**29.4**	**26.5**	**2.2**	**2.0**	**1.8**	**6.0**	**5.8**	**5.7**
RIL	Jamnagar (DTA) (1999)	33.0	33.0	34.1	2.6	2.6	2.7	8.2	8.2	8.3
	Jamnagar (SEZ) (2008)	35.2	35.9	26.8	2.0	2.0	2.5	7.1	7.1	7.5
NEL	Vadinar (2006)	20.0	20.6	17.1	1.4	1.4	1.6	4.4	4.4	5.0
All India (MMT)		**249.9**	**254.4**	**221.8**	**17.5**	**19.2**	**18.4**	**48.6**	**58.9**	**57.3**
All India (Million Bbl/Day)		**5.02**	**5.09**	**4.45**	**4.28**		**4.50**	**3.92**		**4.61**

Note: Provisional Targets; Some sub-totals/ totals may not add up due to rounding off at individual levels.

9. Major crude oil and product pipeline network (as on 01.07.2021)

Details		ONGC	OIL	Cairn	HMEL	IOCL	BPCL	HPCL	Others*	Total
Crude Oil	Length (KM)	1,283	1,193	688	1,017	5,301	937			**10,419**
	Cap (MMTPA)	60.6	9.0	10.7	11.3	48.6	7.8			**147.9**
Products	Length (KM)		654			9,400	2,241	3,775	2,395	**18,465**
	Cap (MMTPA)		1.7			47.5	19.5	34.1	9.4	**112.2**

*Others include GAIL and Petronet India. HPCL and BPCL lubes pipeline included in products pipeline data

12. Production and consumption of petroleum products (Million Metric Tonnes)												
Products	2019-20		2020-21 (P)		June 2020 (P)		June 2021 (P)		Apr-Jun 2020 (P)		Apr-Jun 2021 (P)	
	Prod	Cons	Prod	Cons	Prod	Cons	Prod	Cons	Prod	Cons	Prod	Cons
LPG	12.8	26.3	12.1	27.6	1.0	2.1	0.9	2.3	2.9	6.5	3.0	6.5
MS	38.6	30.0	35.8	28.0	2.9	2.3	2.8	2.4	7.3	5.0	9.1	6.8
NAPHTHA	20.6	14.3	19.4	14.3	1.4	1.2	1.6	1.2	4.4	3.0	4.9	3.7
ATF	15.2	8.0	7.1	3.7	0.4	0.2	0.7	0.3	1.3	0.4	2.2	0.9
SKO	3.2	2.4	2.3	1.8	0.2	0.2	0.1	0.1	0.6	0.5	0.4	0.4
HSD	111.1	82.6	100.4	72.7	8.0	6.3	8.3	6.2	22.0	15.0	25.4	18.4
LDO	0.6	0.6	0.7	0.8	0.06	0.1	0.08	0.1	0.1	0.2	0.2	0.3
LUBES	0.9	3.8	1.1	3.5	0.1	0.2	0.1	0.3	0.2	0.6	0.2	0.8
FO/LSHS	9.3	6.3	8.2	6.0	0.8	0.5	0.6	0.5	2.3	1.3	1.8	1.5
BITUMEN	4.9	6.7	4.9	7.1	0.5	0.8	0.3	0.5	0.9	1.5	1.2	1.7
PET COKE	14.6	21.7	12.0	18.3	1.0	1.4	1.1	1.6	3.0	4.7	3.3	4.8
OTHERS	31.0	11.4	29.5	10.8	2.5	0.8	2.6	0.8	7.0	2.2	8.2	2.6
ALL INDIA	**262.9**	**214.1**	**233.4**	**194.6**	**18.7**	**16.1**	**19.2**	**16.3**	**52.0**	**40.8**	**60.0**	**48.5**
Growth (%)	**0.2%**	**0.4%**	**-11.2%**	**-9.1%**	**-8.9%**	**-9.0%**	**2.4%**	**1.5%**	**-18.2%**	**-26.1%**	**15.4%**	**18.8%**

Note: Prod - Production; Cons - Consumption

16. LPG consumption (Thousand Metric Tonne)

LPG category	2019-20	2020-21 (P)	June			April-June		
			2020-21 (P)	2021-22 (P)	Gr (%)	2020-21 (P)	2021-22 (P)	Gr (%)
1. PSU Sales :								
LPG-Packed Domestic	23,076.0	25,117.1	1,922.5	2,045.9	6.4	6,172.6	6,005.7	-2.7
LPG-Packed Non-Domestic	2,614.4	1,884.9	102.3	159.5	55.9	226.9	396.6	74.8
LPG-Bulk	263.5	355.5	23.3	37.5	61.3	46.9	84.5	80.1
Auto LPG	171.9	118.3	8.5	8.1	-5.2	14.3	22.0	53.4
Sub-Total (PSU Sales)	26,125.7	27,475.7	**2,056.6**	**2,251.0**	**9.5**	**6,460.7**	**6,508.7**	**0.7**
2. Direct Private Imports*	204.0	114.8	6.0	11.9	97.7	8.0	35.6	343.4
Total (1+2)	26,329.8	27,590.5	**2,062.6**	**2,262.9**	**9.7**	**6,468.7**	**6,544.3**	**1.2**

*Jul 2020-Jun 2021 DGCIS data prorated

17. LPG marketing at a glance

Particulars (As on 1st of April)	Unit	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021 (P)	1.7.2021 (P)
LPG Active Domestic Customers	(Lakh)						1486	1663	1988	2243	2654	2787	2895	2911
	Growth							11.9%	19.6%	12.8%	18.3%	5.0%	3.9%	3.5%
LPG Coverage (Estimated)	(Percent)						56.2	61.9	72.8	80.9	94.3	97.5	99.8	#99.8
	Growth							10.1%	17.6%	11.1%	16.5%	3.4%	2.3%	1.8%
PMUY Beneficiaries	(Lakh)								200	356	719	802	800.4	800.3
	Growth									77.7%	101.9%	11.5%	-0.2%	-0.2%
LPG Distributors	(No.)	9686	10541	11489	12610	13896	15930	17916	18786	20146	23737	24670	25083	25116
	Growth	3.4%	8.8%	9.0%	9.8%	10.2%	14.6%	12.5%	4.9%	7.2%	17.8%	3.9%	1.7%	1.5%
Auto LPG Dispensing Stations	(No.)	536	604	652	667	678	681	676	675	672	661	657	651	650
	Growth	19.9%	12.7%	7.9%	2.3%	1.6%	0.4%	-0.7%	-0.1%	-0.4%	-1.6%	-0.6%	-0.9%	-1.1%
Bottling Plants	(No.)	182	183	184	185	187	187	188	189	190	192	196	200	199
	Growth	0.0%	0.5%	0.5%	0.5%	1.1%	0.0%	0.5%	0.5%	0.5%	1.1%	2.1%	2.0%	2.1%

Source: PSU OMCs (IOCL,BPCL and HPCL);

Note: Growth rates as on 1.7.2021 are w.r.t. figures as on 1.7.2020. All growth rates as on 1 April of any year are w.r.t. figures as on 1 April of previous year;

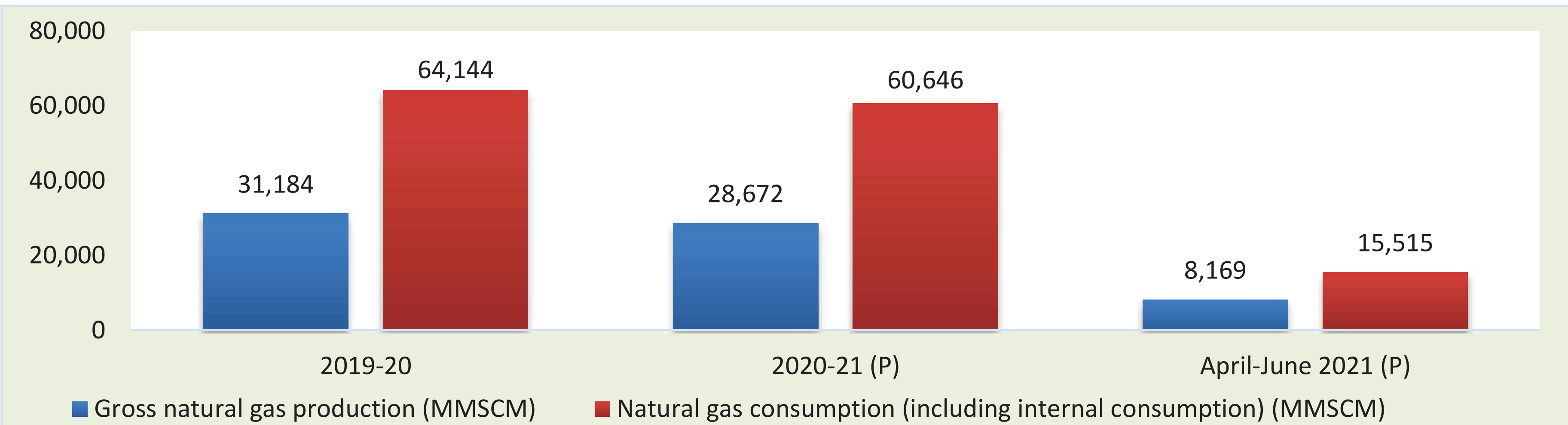
LPG coverage figure pertains to 01.04.2021 as the methodology used for estimating LPG coverage by PSU OMC's is under review.

19. Natural gas at a glance

(MMSCM)

Details	2019-20	2020-21 (P)	June 2020-21 (P)	June 2021-22 (Target)	June 2021-22 (P)	April-June 2020-21 (P)	April-June 2021-22 (Target)	April-June 2021-22 (P)
(a) Gross production	31,184	28,672	2,324	2,931	2,777	6,785	8,467	8,169
- ONGC	23,746	21,872	1,819	1,908	1,685	5,351	5,603	5,052
- Oil India Limited (OIL)	2,668	2,480	219	243	230	650	733	675
- Private / Joint Ventures (JVs)	4,770	4,321	286	781	862	785	2,131	2,441
(b) Net production (excluding flare gas and loss)	30,257	27,785	2,250		2,714	6,531		7,957
(c) LNG import#	33,887	32,861	2,800		2,316	6,998		7,558
(d) Total consumption including internal consumption (b+c)	64,144	60,646	5,050		5,030	13,530		15,515
(e) Total consumption **(in BCM)**	64.1	60.6	5.1		5.0	13.5		15.5
(f) Import dependency based on consumption (%), {c/d*100}	52.8	54.2	55.4		46.1	51.7		48.7

#Jul 2020-Jun 2021 DGCIS data prorated; RIL data prorated



20. Coal Bed Methane (CBM) gas development in India

Prognosticated CBM resources		91.8	TCF
Established CBM resources		10.4	TCF
CBM Resources (33 Blocks)		62.8	TCF
Total available coal bearing areas (India)		32760	Sq. KM
Total available coal bearing areas with MoPNG/DGH		21659	Sq. KM
Area awarded		16613	Sq. KM
Blocks awarded (ST CBM Block awarded twice in CBM Round II and Round IV)		32	Nos.
Exploration initiated (Area considered if any boreholes were drilled in the awarded block)		10669.55	Sq. KM
Production of CBM gas	April-June 2021 (P)	172.09	MMSCM
Production of CBM gas	June 2021 (P)	56.70	MMSCM

21. Natural gas pipeline network as on 31.12.2020

Nature of pipeline		GAIL	GSPL	PIL	IOCL	AGCL	RGPL	GGL	DFPCL	ONGC	GIGL	GITL	Others*	Total
Operational	Length	8,241	2,265	1,460	132	105	312	73	42	24				**12,654**
	Capacity	171.6	43.0	85.0	20.0	2.4	3.5	5.1	0.7	6.0				**337.3**
Partially commissioned[#]	Length	3,643			23						442	364		**4,472**
	Capacity	-			-						-	-		**-**
Total operational length		**11,884**	**2,265**	**1,460**	**155**	**105**	**312**	**73**	**42**	**24**	**442**	**364**	**0**	**17,126**
Under construction	Length	6,242			1,398						2,335	1,678	3,780	**15,433**
	Capacity	23.2			-						-	-	157.7	**-**
Total length		**18,126**	**2,265**	**1,460**	**1,553**	**105**	**312**	**73**	**42**	**24**	**2,777**	**2,042**	**3,780**	**32,559**

Source: PNGRB; Length in KMs ; Authorized Capacity in MMSCMD; *Others-APGDC, HEPL, IGGL, IMC, Consortium of H-Energy

22. Existing LNG terminals

Location	Promoters	Capacity as on 01.07.2021	% Capacity utilisation (Apr-May 2021)
Dahej	Petronet LNG Ltd (PLL)	17.5 MMTPA	80.2
Hazira	Shell Energy India Pvt. Ltd.	5 MMTPA	50.0
Dabhol	Konkan LNG Limited	*5 MMTPA	100.0
Kochi	Petronet LNG Ltd (PLL)	5 MMTPA	24.7
Ennore	Indian Oil LNG Pvt Ltd	5 MMTPA	16.0
Mundra	GSPC LNG Limited	5 MMTPA	28.6
Total Capacity		**42.5 MMTPA**	

* To increase to 5 MMTPA with breakwater. Only HP stream of capacity of 2.9 MMTPA is commissioned

https://www.reuters.com/world/africa/mozambiques-gas-ambitions-rest-distant-hope-peace-2021-07-22/
July 22, 20211:12 AM MDTLast Updated 8 hours ago

Analysis: Mozambique's gas ambitions rest on distant hope of peace

Emma RumneyDavid Lewis

- TotalEnergies declared force majeure after deadly attack
- Battered government forces in need of support
- Regional and international allies offer troops, training
- Experts say restoring peace could take years

JOHANNESBURG, July 22 (Reuters) - The future of Mozambique's gas ambitions hinges on its ability to end a deadly insurgency linked to Islamic State, but if peace is the answer the southern African country and French energy giant TotalEnergies (TTEF.PA) may have a problem.

Four months after gunmen overran Palma, a town housing TotalEnergies contractors near its Afungi site in Cabo Delgado province, the insurgents still control swathes of territory and a key port while the army is in tatters, security experts, military personnel, company officials and insiders told Reuters.

TotalEnergies has said its $20 billion gas project will remain on hold until security is restored in the province in a "verifiable and sustainable manner". At the end of April, it estimated the delays would last at least a year. read more

The Mozambican government says Palma itself is now pacified and it is working to ensure peace in Cabo Delgado.

But as recently as June, the United Nations refugee agency said people fleeing areas adjacent to the TotalEnergies site reported ongoing insecurity and gunfire.

"A year strikes me as very optimistic," said Sam Ratner, an analyst with Cabo Ligado, a media and civil society project tracking the violence in northern Mozambique.

An even bigger project led by Exxon Mobil (XOM.N) is now also on hold with minority partner Galp (GALP.LS) telling Reuters that re-establishing security was essential and that it would not move forward until TotalEnergies returns. read more

TotalEnergies declined to comment for this article. An Exxon spokesperson said the company continues to evaluate the security situation. Government officials did not respond to questions.

Mozambique's gas reserves are estimated at some 100 trillion cubic feet, putting the country 11th in world rankings, and the two liquefied natural gas (LNG) projects are at the heart of the transformation plan of one of the world's poorest countries.

TotalEnergies and Exxon, meanwhile, hope Mozambique will help plug LNG shortfalls expected in the middle of the decade. TotalEnergie's project was due to produce 12.9 million tonnes per annum initially from 2024 which Credit Suisse estimates is equivalent to about a year's worth of global LNG demand growth.

NO MATCH

Security analysts, however, say the military deficiencies that allowed the insurgency to take hold in the north of Mozambique won't be easily reversed. They say soldiers are ill-equipped, undisciplined and poorly paid, leading to low morale.

"We are nowhere near a match for them," one soldier said of the Islamists after the Palma attack, adding that the insurgents also knew the terrain better.

The Southern African Development Community (SADC) has agreed to send soldiers to the region after it secured a concession from Mozambique's President Filipe Nyusi, who had initially resisted any foreign intervention. Some Rwandan troops have also started to arrive in Cabo Delgado. read more

But SADC has no counter-insurgency experience, nor has it provided details of troop numbers, deployment dates or the mission's scope. Its initial budget of $12 million is tiny given the scale of the task, said Alexandre Raymakers, senior Africa analyst at Verisk Maplecroft.

SADC did not respond to a request for comment.

The United States, Portugal and European Union have also offered help with training, logistics and intelligence to tackle the Islamist insurgency, which erupted in 2017 and has killed thousands of civilians, soldiers and militants.

But experts - pointing to examples such as France's decade-long counter-insurgency efforts in West Africa's Sahel region - warn such assistance could take years to show results.

And if the attack on Palma is anything to go by, the local forces will need more training.

RUNNING AWAY

After a spike in violence forced TotalEnergies to suspend work last year, it asked the government for a 1,000-strong force to protect its site and a 25 km (15 mile) security perimeter.

But even as they sought to shore up Afungi, the insurgents were closing in. Hours after TotalEnergies announced the resumption of work on March 24, they attacked, eventually getting within 2 km of the site and forcing its evacuation.

The troops protecting Afungi did not defend the town, a contractor whose firm was in communication with the company and a person with direct knowledge of TotalEnergies' operation said.

Hundreds of contractors supporting the project were caught in the violence. At least one was killed trying to escape from a besieged hotel. Five told Reuters they would not return without greater assurances from TotalEnergies about security. read more

In the months ahead of the attack, government forces had left Mocimboa da Praia - a port just 80 km away - in insurgent hands since August, allowing them a launch pad from which some analysts believe they staged the Palma attack.

Footage posted by Islamic State's Amaq news agency, which a Reuters' analysis geolocated to the port town, showed fighters gathering there, probably in the days before the Palma attack.

Security firms advising Palma-based contractors flagged nearby probing attacks ahead of the assault, internal messages seen by Reuters showed. But there was no noticeable increase in security in the town, said four contractors living there.

During the fighting, two eye witnesses told Reuters they saw soldiers fleeing. Those who stayed said they were out gunned.

Vehicles, businesses, contractors' sites and banks were looted during the violence, analysts say, with some spoils carried off by the insurgents giving them a temporary boost.

FORT KNOX WON'T WORK

The ordeal convinced TotalEnergies that the insecurity pervading Cabo Delgado province could no longer be tolerated.

"It's not Total that's going to re-establish peace," Patrick Pouyanne, chief executive of TotalEnergies, told investors in May. "We're not going to build a facility inside a Fort Knox ... that won't work."

And military action alone won't address the political and economic exclusion feeding the insurgents' ranks, said Dino Mahtani of the International Crisis Group, a Brussels-based research group.

"Military action needs to take place, but in a measured way that dovetails with the efforts of the state to also remedy what is a grass roots problem," he said.

A TotalEnergies source told Reuters on condition of anonymity that the company's engineers might look again at the option of moving the project offshore but that would have its own technical and political challenges.

Such a move would require the government to accept missing out on the boost to local jobs and the poor northern region in general it is counting on for economic development, an official working with TotalEnergies said.

Ultimately, success hinges on the Mozambican authorities, though time was running out, the official said.

"I don't see a short-term solution ... The government has failed so many times."

Reporting by Emma Rumney in Johannesburg and David Lewis in Nairobi; Additional reporting by Ron Bousso in London, Benjamin Mallet in Paris, Manuel Mucari in Maputo, Joe Bavier in Johannesburg and Eleanor Whalley in London; Editing by Joe Bavier and David Clarke

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

Posted Wednesday April 28, 2021. 9:00 MT

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

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

Total Mozambique Phase 1 and 2

Source: Total Investor Day September 24, 2019

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

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

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

Exxon Mozambique LNG

Source: Exxon Investor Day March 6, 2019

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

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

<u>Will Cdn natural gas be similarly hit by if Trudeau move to "emissions free" and not "net zero emissions" electricity?</u> 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.

<u>Biden's global climate summit reminded there is too much risk to skip over natural gas as the transition fuel.</u> 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

	🟡 Renewable Power	🔴 Geothermal
	🟢 Solar PV	🔴 Ocean Power
	🟡 Onshore Wind	🔴 Nuclear Power
🔴 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
	🟡 Chemicals	🟡 Pulp and Paper
🟡 Industry	🟡 Iron and Steel	🟡 Aluminum
	🟡 Cement	🔴 CCUS in Industry and Transformation
	🟢 Electric Vehicles	🔴 Transport Biofuels
🟡 Transport	🟢 Rail	🟡 Aviation
	🔴 Fuel Consumption of Cars and Vans	🟡 International Shipping
	🟡 Trucks and Busses	
	🔴 Building Envelopes	🟢 Lighting
🔴 Buildings	🔴 Heating	🟡 Appliances and Equipment
	🟡 Heat Pumps	🟢 Data Centres and Data Transmission Networks
	🟡 Cooling	
	🟡 Energy Storage	🟡 Demand Response
🟡 Energy Integration	🟡 Hydrogen	🟡 Direct Air Capture
	🟡 Smart Grids	

Source: IEA

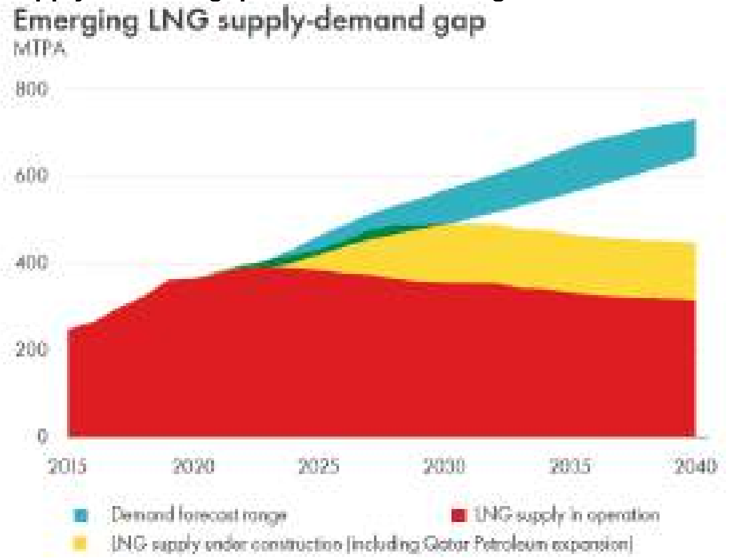
🟢 On Track 🟡 More Efforts Needed 🔴 Not on Track

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

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.. 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.

And does this bigger, nearer supply gap force LNG players to look at what brownfield LNG projects they could advance? A greenfield LNG project would likely take at least until 2027 to be in operations. Its why we believe the Mozambique delays will effectively force major LNG players to look to see if there are brownfield LNG projects they should look to advance. Prior to the just passed winter, no one would think Shell or other major LNG players would be considering any new LNG FIDs in 2021. All the big companies are in capital reduction mode and debt reduction mode. But Brent oil is now solidly over $60 and LNG prices hit record levels in Jan and the world's economic and oil and gas demand outlook are increasing with vaccinations. And we are starting to see companies move to increasing capex with the higher cash flows. We would not expect any major LNG players to move to FID right away. But we see them watching to see if 2021 plays out to still support this increasing LNG supply gap. And unless new mutations prevent vaccinations from returning the world to normal, we suspect that major LNG players, like other oil and gas companies, will be looking to increase capex as they approve 2022 budgets. The outlook for the future has changed dramatically in the last 5 months. The question facing Shell and others, should they look to FID new LNG brownfield projects in the face of an increasing LNG supply gap that is going to hit faster and harder than expected a few months ago. We expect these decisions to be looked at before the end of 2021. LNG prices will be stronger, but we expect the limiting cap in Asia will be that thermal coal will be used to mitigate some LNG price pressure.

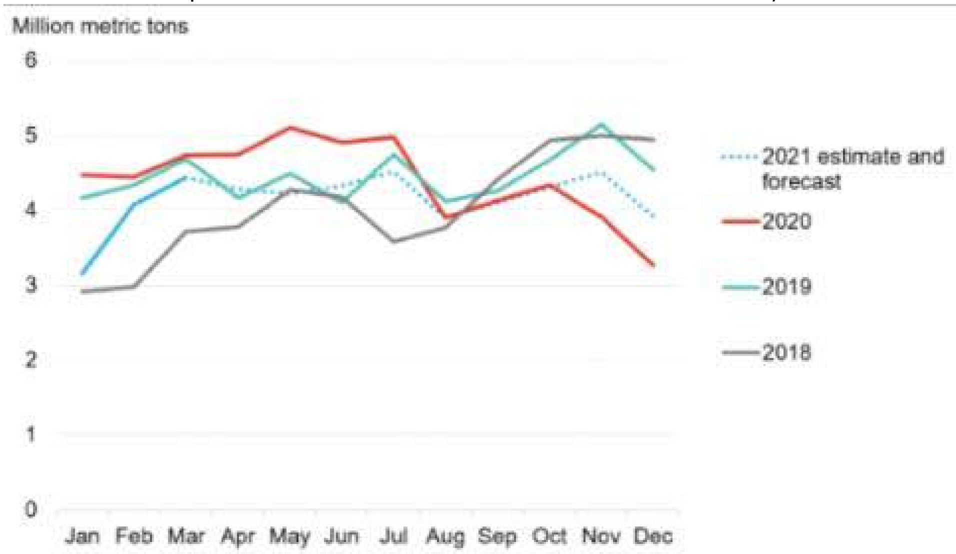
Back to Shell, does increasing LNG supply gap provide the opportunity to at least consider a LNG Canada Phase 2 FID over the next 9 months? Shell is no different than any other major LNG supplier in always knowing the market and that the oil and gas outlook is much stronger than 6 months ago. No one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

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

Japan LNG Inventories Recover in Time for Peak Summer: BNEF
2021-07-21 07:35:02.80 GMT

By Olympe Mattei
(BloombergNEF) -- Japan’s end-June liquefied natural gas inventories are estimated to have recovered to the past three-year average. The world’s largest importer of the chilled fuel will likely have enough stockpiles to get through the summer demand period.
Japan inventories reached a low point in January, but recovered to 4.4 million tons by March, as per statistics from the Ministry of Economy, Trade and Industry (METI). This would indicate a more steady recovery of stocks up to June than previous BloombergNEF estimates at about 4.3 million tons. Summer peak power demand in August could draw inventories down, as more gas generation is needed to meet cooling needs. BNEF expects withdrawals to take place this year, in line with usual seasonal patterns. August LNG storage withdrawals averaged 0.8 million tons in 2019 and 2020.
By September, Japan is set to announce new guidelines on the minimum LNG stockpiles to guarantee sufficient supply. Higher inventory requirements could boost winter LNG purchases from players such as Jera Co. and Tokyo Gas Co.

Japan end-of-month LNG inventories (Note: Actual until March 2021, based on the following tickers (JP44INLN Index <GO> for electric utilities, {JPJKLNGI Index <GO> for gas utilities. Estimates from April to June based on ad-hoc data releases from METI.)



For more BNEF analysis on this topic, see here

To contact BloombergNEF about this article click here.
To contact the author:
Olympe Mattei in London at omattei@bloomberg.net
To contact the editor responsible for this article:
Iain Wilson at iwilson2@bloomberg.net

https://www.nord-stream.com/press-info/press-releases/nord-stream-pipeline-resumes-gas-transmission-after-completion-of-maintenance-works-520/

Nord Stream Pipeline Resumes Gas Transmission After Completion of Maintenance Works

All planned maintenance works on the gas pipelines have been completed on time

July 23, 2021 | Zug, Switzerland | Nord Stream AG has successfully completed all planned maintenance works on its twin gas pipelines within the scheduled period. After the temporary shutdown of the pipeline system, gas transmission resumed on 23 July 2021
Nord Stream's Operations and Maintenance teams as well as external contractors carried out the inspection and maintenance safely and with all necessary protection measures against COVID-19.

The annual maintenance works contribute to a reliable, safe, and efficient gas supply to the European market.

The schedule for the maintenance activities has been closely coordinated with Nord Stream's upstream and downstream partners and appropriately disclosed in compliance with Regulation (EU) Nr.1227/2011 (Regulation on Wholesale Energy Market Integrity and Transparency – REMIT).

https://www.state.gov/joint-statement-of-the-united-states-and-germany-on-support-for-ukraine-european-energy-security-and-our-climate-goals/

Joint Statement of the United States and Germany on Support for Ukraine, European Energy Security, and our Climate Goals

MEDIA NOTE

OFFICE OF THE SPOKESPERSON

JULY 21, 2021

The text of the following statement was released by the Governments of the United States of America and Germany.

Begin text:

The United States and Germany are steadfast in their support for Ukraine's sovereignty, territorial integrity, independence, and chosen European path. We recommit ourselves today to push back against Russian aggression and malign activities in Ukraine and beyond. The United States pledges to support Germany's and France's efforts to bring peace to eastern Ukraine via the Normandy Format. Germany will intensify its efforts within the Normandy Format to facilitate the implementation of the Minsk agreements. The United States and Germany affirm their commitment to tackling the climate crisis and taking decisive action to reduce emissions in the 2020s to keep a 1.5-degree Celsius temperature limit within reach.

The United States and Germany are united in their determination to hold Russia to account for its aggression and malign activities by imposing costs via sanctions and other tools. We commit to working together via the newly established U.S.-EU High Level Dialogue on Russia, and via bilateral channels, to ensure the United States and the EU remain prepared, including with appropriate tools and mechanisms, to respond together to Russian aggression and malign activities, including Russian efforts to use energy as a weapon. Should Russia attempt to use energy as a weapon or commit further aggressive acts against Ukraine, Germany will take action at the national level and press for effective measures at the European level, including sanctions, to limit Russian export capabilities to Europe in the energy sector, including gas, and/or in other economically relevant sectors. This commitment is designed to ensure that Russia will not misuse any pipeline, including Nord Stream 2, to achieve aggressive political ends by using energy as a weapon.

We support the energy security of Ukraine and Central and Eastern Europe, including the key principles enshrined in the EU's Third Energy Package of diversity and security of supply. Germany underscores that it will abide by both the letter and the spirit of the Third Energy Package with respect to Nord Stream 2 under German jurisdiction to ensure unbundling and third-party access. This includes an assessment of any risks posed by certification of the project operator to the security of energy supply of the EU.

The United States and Germany are united in their belief that it is in Ukraine's and Europe's interest for gas transit via Ukraine to continue beyond 2024. In line with this belief, Germany commits to utilize all available leverage to facilitate an extension of up to 10 years to Ukraine's gas transit agreement with Russia, including appointing a special envoy to support those negotiations, to begin as soon as possible and no later than September 1. The United States commits to fully support these efforts.

The United States and Germany are resolute in their commitment to the fight against climate change and ensuring the success of the Paris Agreement by reducing our own emissions in line with net-zero by 2050 at the latest, encouraging the strengthening of climate ambition of other major economies, and collaborating on the policies and technologies to accelerate the global net-zero transition. That is why we have launched the U.S.-Germany Climate and Energy Partnership [**see fact sheet**]. The Partnership will foster U.S.-Germany collaboration on developing actionable roadmaps to reach our ambitious emission reduction targets; coordinating our domestic policies and priorities in sectoral decarbonization initiatives and multilateral fora; mobilizing investment in energy transition; and developing, demonstrating, and scaling critical energy technologies such as renewable energy and storage, hydrogen, energy efficiency, and electric mobility.

As part of the U.S.-Germany Climate and Energy Partnership, we have decided to establish a pillar to support the energy transitions in emerging economies. This pillar will include a focus on supporting Ukraine and other countries in Central and Eastern Europe. These efforts will not only contribute to the fight against climate change but will support European energy security by reducing demand for Russian energy.

In line with these efforts, Germany commits to establish and administer a Green Fund for Ukraine to support Ukraine's energy transition, energy efficiency, and energy security. Germany and the United States will endeavor to promote and support investments of at least $1 billion in the Green Fund for Ukraine, including from third parties such as private-sector entities. Germany will provide an initial donation to the fund of at least $175 million and will work toward extending its commitments in the coming budget years. The fund will promote the use of renewable energy; facilitate the development of hydrogen;

increase energy efficiency; accelerate the transition from coal; and foster carbon neutrality. The United States plans to support the initiative via technical assistance and policy support consistent with the objectives of the fund, in addition to programs supporting market integration, regulatory reform, and renewables development in Ukraine’s energy sector.

In addition, Germany will continue to support bilateral energy projects with Ukraine, especially in the field of renewables and energy efficiency, as well as coal transition support, including the appointment of a special envoy with dedicated funding of $70 million. Germany is also ready to launch a Ukraine Resilience Package to support Ukraine’s energy security. This will include efforts to safeguard and increase the capacity for reverse flows of gas to Ukraine, with the aim of shielding Ukraine completely from potential future attempts by Russia to cut gas supplies to the country. It will also include technical assistance for Ukraine’s integration into the European electricity grid, building on and in coordination with the ongoing work by the EU and the U.S. Agency for International Development. In addition, Germany will facilitate Ukraine’s inclusion in Germany’s Cyber Capacity Building Facility, support efforts to reform Ukraine’s energy sector, and assist with identifying options to modernize Ukraine’s gas transmission systems.

The United States and Germany express their strong support for the Three Seas Initiative and its efforts to strengthen infrastructure connectivity and energy security in Central and Eastern Europe. Germany commits to expand its engagement with the initiative with an eye toward financially supporting projects of the Three Seas Initiative in the fields of regional energy security and renewable energy. In addition, Germany will support projects of common interest in the energy sector via the EU Budget, with contributions of up to $1.77 billion in 2021-2027. The United States remains committed to investing in the Three Seas Initiative and continues to encourage concrete investments by members and others.

End text.

https://www.gazprom.com/press/news/2021/july/article533858/

Alexey Miller: "Gazprom has always approached Nord Stream 2 as an economic project"

RELEASE

July 22, 2021, 18:30

Nord Stream and Nord Stream 2

"Gazprom has always approached Nord Stream 2 as an economic project. Its goal is to provide reliable, stable and diversified supplies of gas to the market of the European Union. It also aims to reduce the cost of gas for end consumers via a shorter transportation route that reaches Germany almost 2,000 kilometers ahead of the route traversing the gas transmission system of Ukraine, as well as to ensure compliance with all current environmental requirements. For instance, CO_2 emissions from Nord Stream 2 are 5.6 times lower thanks to, among other things, a reduced number of compressor stations compared to the Ukrainian route.

It should be noted that Gazprom has always stressed its readiness to continue transiting gas across Ukraine, including after 2024, based on economic viability and the technical condition of Ukraine's gas transmission system.

The issues pertaining to new volumes of gas to be purchased from Russia for transit via Ukraine need to be settled under market conditions and at market prices. If the aggregate of the new volumes of Russian gas to be purchased and transited via the Ukrainian route exceeds the current transit obligations, Gazprom will readily increase the volumes of gas transit across Ukraine.

We consider our German partners to be entirely justified in taking part in this work due to the announced plans for the decarbonization of the EU economy."

Director's Cut
May 2021 Production

Oil Production

April	33,694,990 barrels = 1,123,166 barrels/day (final)
May	34,953,034 barrels = 1,127,517 barrels/day (all-time high 1,519,037 BOPD Nov 2019)
	1,084,752 barrels/day or 96% from Bakken and Three Forks 42,766 barrels/day or 4% from legacy pools
Revised Revenue Forecast	**= 1,200,000→1,100,000→1,000,000 barrels/day**

Crude Price[1] ($/barrel)

	North Dakota Light Sweet	WTI	ND Market estimate
April	55.35	61.65	56.82
May	58.28	65.06	59.69
June	63.62	71.53	67.58
Today	58.50	66.42	62.46
All-time high (6/2008)	$125.62	$134.02	$126.75
Revised Revenue Forecast			**= $50.00**

Gas Production & Capture

April Production	88,470,160 MCF = 2,949,005 MCF/day
Gas Captured: 94%	82,771,035 MCF = 2,759,035 MCF/day
May Production	92,411,537 MCF = 2,981,017 MCF/day (all-time high 3,145,172 MCFD Nov 2019)
Gas Captured: 92%	85,095,332 MCF = 2,745,011 MCF/day (all-time high 2,899,998 MCFD Mar 2020)

Rig Count

April	15
May	19
June	20
Today	23
Federal Surface	0
All-time high	*218 (5/29/2012)*

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

Wells

	April	May	June	Revised Revenue Forecast
Permitted	51 drilling 0 seismic	46 drilling 0 seismic	75 drilling 0 seismic (All-time high was 370 – Oct. 2012)	-
Completed	31 (Final)	41 (Revised)	47 (Preliminary)	**30→40→50→60**
Inactive[2]	2,088	2,348	-	-
Waiting on Completion[3]	731	677	-	-
Producing	16,395	16,612 (Preliminary) (NEW all-time high 16,612 in April 2021) *14,414 (87%) from unconventional Bakken – Three Forks* *2,198 (13%) from legacy conventional pools*	-	-

Fort Berthold Reservation Activity

	Total	Fee Land	Trust Land
Oil Production (barrels/day)	256,384	101,918	154,455
Drilling Rigs	2	1	1
Active Wells	2,568	642	1,926
Waiting on completion	64		
Approved Drilling Permits	226	29	197
Potential Future Wells	3,984	1,122	2,862

Drilling and Completions Activity & Crude Oil Markets

The drilling rig count was stable in the mid 50's second half of 2019 through May 2020. Drilling rig count fell 65% from January 2020 to May 2021 and is slowly increasing.

The number of well completions has been low and volatile since April 2020 as the number of active completion crews dropped from 25 to 1 then increased to 6 in May 2021 and to 8 this week.

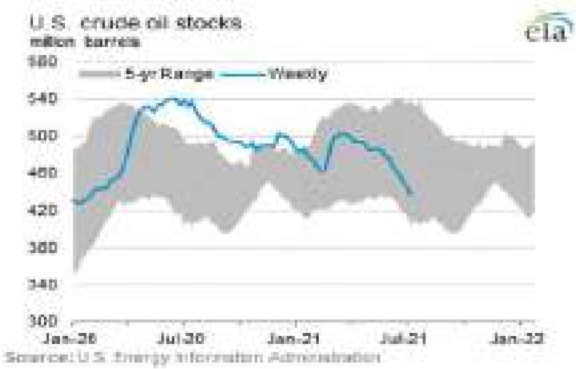
OPEC+ reached a deal Sunday to phase out 5.8 million barrels per day of oil production cuts by September 2022 as prices of the commodity hit their highest levels in more than two years. Coordinated increases in oil supply from the group, known as OPEC+, will begin in August. Overall production will increase by 400,000 barrels per day on a monthly basis from that point onward.

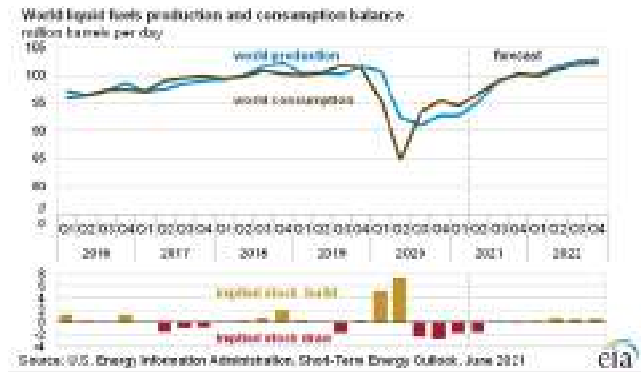
The International Energy Agency estimates a 1.5 million barrel per day shortfall for the second half of this year, indicating a tight market despite the gradual OPEC supply boost. EIA now estimated that supply and demand are balanced with demand returning to 2019 levels until second quarter 2022.

---

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

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





Crude oil transportation capacity including rail deliveries to coastal refineries is adequate, but could be disrupted due to:

- US Appeals Court for the ninth circuit upholding of a lower court ruling protecting the Swinomish Indian Tribal Community's right to sue to enforce an agreement that restricts the number of trains that can cross its reservation in northwest Washington state.
- DAPL Civil Action No. 16-1534 continues, but the courts have now ruled that DAPL can continue normal operations through March 2022.

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

Gas Capture

US natural gas storage is now 7% below the five-year average. Crude oil inventories are below normal in the US, but world storage is above the five-year average.

The price of natural gas delivered to Northern Border at Watford City increased to $23.42/MCF February 17 and has returned to a significantly higher than normal level of $3.26/MCF today. This results in a current oil to gas price ratio of 19 to 1. The state wide gas flared volume from April to May increased 46,036 MCFD to 236,008 MCF per day, and the percent flared increased to 7.8% while Bakken capture percentage decreased to 93%.

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

Gas Capture Details:

Statewide……………….	92%
Statewide Bakken……...	93%
Non-FBIR Bakken……..	93%
FBIR Bakken…………..	93%
Trust FBIR Bakken...	93%
Fee FBIR……………	84%

The Commission established the following gas capture goals:

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

Seismic

Seismic activity has stopped.

Active Surveys	Recording	NDIC Reclamation Projects	Remediating	Suspended	Permitted
0	0	0	0	4	0

Agency Updates

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

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

The U.S. Interior Department announced 3/9/21 it will launch its review of the federal oil and gas leasing program on 3/25/21, a key step that will determine whether the Biden administration will permanently halt new leases on federal land and water. The review will kick off with a public forum on oil and gas leasing on federal land and water, with participants representing industry, environmental conservation and justice groups, labor and others, and commence an online comment period. This input would inform an interim report to be released in early summer outlining next steps and recommendations on the future of the program and what can be done to reform how leases are managed, how much revenue should go to taxpayers and other issues.

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

https://bismarcktribune.com/news/state-and-regional/north-dakota-oil-output-flat-as-a-pancake-amid-frack-crew-shortage/article_6971f0fd-b3f9-5447-91ff-4f815434504a.html

North Dakota oil output 'flat as a pancake' amid frack crew shortage

AMY R. SISK
Jul 20, 2021

A North Dakota regulator says the state's oil output is "flat as a pancake" due a lack of crews available to frack wells.

The oil industry in North Dakota is undergoing a workforce shortage as it recovers from the coronavirus pandemic. The shortage is felt particularly hard by companies in need of crews to inject water, sand and chemicals down wells to crack open rock and release oil. The process, known as fracking or hydraulic fracturing, is a key step before a well drilled in the Bakken can begin producing oil.

Eight such crews are working in North Dakota, up from just one at the height of the downturn brought on by the pandemic last year, State Mineral Resources Director Lynn Helms said. He would typically expect at least 20 operating in the state at today's oil prices. West Texas Intermediate crude, the U.S. pricing benchmark, was trading near $70 per barrel on Tuesday.

"Most of these folks went to Texas where activity was still significantly higher than it was here, where they didn't have winter and where there were jobs in their industry," Helms said. "It's going to take higher pay and housing incentives and that sort of thing to get them here."

North Dakota's oil production rose 4,000 barrels per day in May, the latest month for which data is available. That is a negligible increase, and the state produced 1.128 million barrels of oil per day that month. State data lags several months, and the data for May was released Tuesday.

The fracking side of the industry is also experimenting with new techniques amid the drought that has plagued North Dakota for most of the year. One business, for example, is looking to use saltwater to supplant some of the freshwater used in the fracking process. The fluid is being transported several miles through a flat line hose tucked inside another hose to prevent leaks until it reaches a fracking site, Helms said.

Such a setup appears to be a way to reduce costs while cutting back on using freshwater, and several other companies have expressed interest in trying similar techniques, he said.

Natural gas production in North Dakota rose 1% in May to 2.981 billion cubic feet per day. Of that amount, 92% was captured and diverted to processing plants or used in other ways. The rest was burned off in flares alongside wells.

The state is meeting its gas capture target of 91% overall, though flaring was particularly bad in May on parts of the Fort Berthold Indian Reservation south of New Town, Helms said. State officials weren't sure what had happened to cause the uptick there, though a lack of pipelines and processing facilities north of Lake Sakakawea has caused flaring to be worse there than elsewhere in the state at times in the past.

North Dakota Pipeline Authority Director Justin Kringstad expects the state will have adequate pipelines and processing infrastructure to accommodate gas for at least the next year and a half but will need more at that point to accommodate growing production.

"We certainly still have a tremendous amount of infrastructure needed to stay on the gas capture challenge in North Dakota," he said.

Reach Amy R. Sisk at 701-250-8252 or **amy.sisk@bismarcktribune.com**.

https://www.willistonherald.com/news/oil_and_energy/tug-of-war-for-labor-leaves-north-dakota-production-flat-in-may/article_0e0d8764-e9cc-11eb-b3be-7fab456a22e3.html

Tug of war for labor leaves North Dakota production flat in May

- By Renée Jean rjean@willistonherald.com
- Jul 21, 2021 Updated 23 hrs ago

Lynn Helms talks about North Dakota oil production in May.
Screenshot

U.S. crude oil stocks have decreased for the eighth week in a row amid rising world demand for crude oil, and North Dakota's oil and gas sector is more than ready to bounce back. But it's in a tug of war right now with Texas and New Mexico for the oil and gas labor it lost during the pandemic. And, right now, it appears the nation's No. 2 oil play could be the underdog in this economic dogfight.

North Dakota Department of Mineral Resources Director Lynn Helms said the dynamic contributed to mostly flat crude oil production from April to May, leaving production at 1.127 million barrels of crude oil per day, and defying hopes for production gains that would keep the state ahead of New Mexico. The latter narrowed the gap between it and North Dakota for the nation's No. 2 oil producer to 90,000 barrels per day.

"They are looming in our rear view mirror," Helms said. "We'll see just how long we can stay ahead in this race with only 23 rigs operating here and 75 operating in New Mexico. It's going to be a severe challenge now."

Helms said his inspectors report only eight hydraulic fracturing crews in the field.

"At these prices, we would normally have 20 to 25 frac crews," he said.

The companies Helms has talked to tell him they are trying "with all their might" to hire workers for completion crews in the Bakken.

“But they are not finding employees that want to come back into the industry and come back to North Dakota to work on the frac crews,” he said.

Pre-pandemic, North Dakota had 25 hydraulic fracturing crews, but it went down to a single crew during the worst of the pandemic in June and July.

“So many of those people were let go,” Helms said, “and many of them have left the state.”

To grow production at this point, Helms said the state needs to double or triple the number of hydraulic fracturing crews operating in the state. Hiring that many people, though, will likely require larger salaries and the return of at least some perks, such as housing allowances.

Whether that’s realistic, given the current ESG climate and the “disciplined” growth that major Bakken producers such as Continental are preaching right now, remains to be seen.

“There are some of our larger producers that have expressed the need and they’re really dialing in 1 to 2 percent growth,” Helms said. That’s lower than statewide projections, he added, “So there is concern this could be a longer-term trend.”

Another factor that’s undercutting the oil and gas sector’s recovery has not been much talked about. Oil is trading in the $70s, but most producers hedged in the $40 to $50 range. That’s leaving billions on the table for many debt-laden oil and gas companies. It will take some time for those hedges to drop off and for those companies to begin benefitting from the market’s price recovery.

Gas production, meanwhile, increased by 1 percent to 2.98 billion cubic feet per day despite the mostly flat oil production, and gas capture lost ground by about the same amount, dropping from 93 to 92 percent.

Contributing to the flaring increase is a turnaround at the Hess plant in Tioga, which takes 250 million cubic feet per day capacity offline at least temporarily. The plant will ultimately be expanded, however, to 400 million cubic feet per day.

Helms said the state might have seen more significant flaring as a result of the turnaround but for the new B. Sanderson plant built by Outrigger in Williams County. That plant was to have taken XTO production, but, since that didn’t happen, the new gas plant had room to help pick up excess gas and help take the edge off capacity issues.

Despite the challenges facing the Bakken, Helms said there are signs that activity is likely to pick up soon, and Helms is hopeful they will translate into production gains for June and July.

“In June, we issued 75 permits,” he said, “and we haven’t been there since before the pandemic, so that’s great news.”

North Dakota also set a new record for active, producing wells despite the lack of drilling rigs and hydraulic fracturing crews.

“(Oil and gas companies) carved into the non-completed wells or the DUC well count pretty substantially,” Helms said. “It went from 731 to 677.”

Included in that record number of producing wells is a feather in the cap for McKenzie County, which can now say it’s the first county in the state to have 5,000 active producing wells.

“To put that in context, in April of 2006, as they were drilling the first big Bakken well over in Parshall, statewide we had 3,525 wells,” Helms said. “So McKenzie County all by itself has 150 percent of the wells the whole state had in 2006.”

Another thing that bodes well for North Dakota as a competitive oil and gas play is the fact that during the pandemic it was the only shale play to increase its production efficiency. That’s according to a report just out from the EIA.

Production stats, meanwhile, are in line with the state’s budget forecast. The only thing not in line are prices, which have exceeded revenue forecast by about 19 percent in May, and were also exceeding it by some 25 percent Tuesday.

“State revenues should be extremely healthy,” Helms said.

MONTHLY UPDATE

MAY 2021 PRODUCTION & TRANSPORTATION

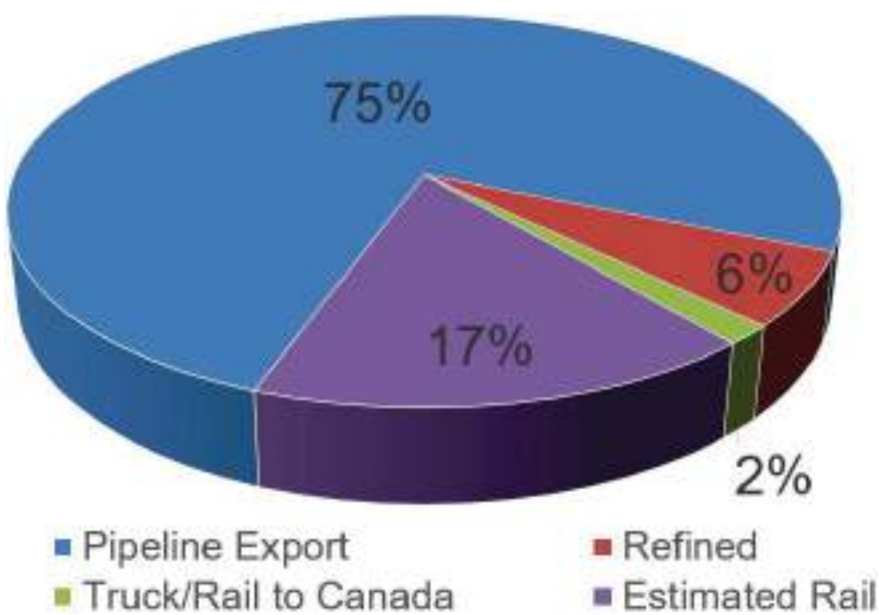
North Dakota Oil Production

Month	Monthly Total, BBL	Average, BOPD
Apr. 2021 - Final	33,694,990	1,123,166
May 2021 - Prelim.	34,953,034	1,127,517

North Dakota Natural Gas Production

Month	Monthly Total, MCF	Average, MCFD
Apr. 2021 - Final	88,470,160	2,949,005
May 2021 - Prelim.	92,411,537	2,981,017

Estimated Williston Basin Oil Transportation, May 2021



CURRENT DRILLING ACTIVITY:

NORTH DAKOTA[1]

22 Rigs

EASTERN MONTANA[2]

0 Rigs

SOUTH DAKOTA[2]

0 Rigs

SOURCE (JULY 20, 2021):

1. ND Oil & Gas Division
2. Baker Hughes

PRICES:

Crude (WTI): $66.95

Crude (Brent): $69.25

NYMEX Gas: $3.87

SOURCE: BLOOMBERG (JULY 20, 2021)

GAS STATS*

92% CAPTURED & SOLD

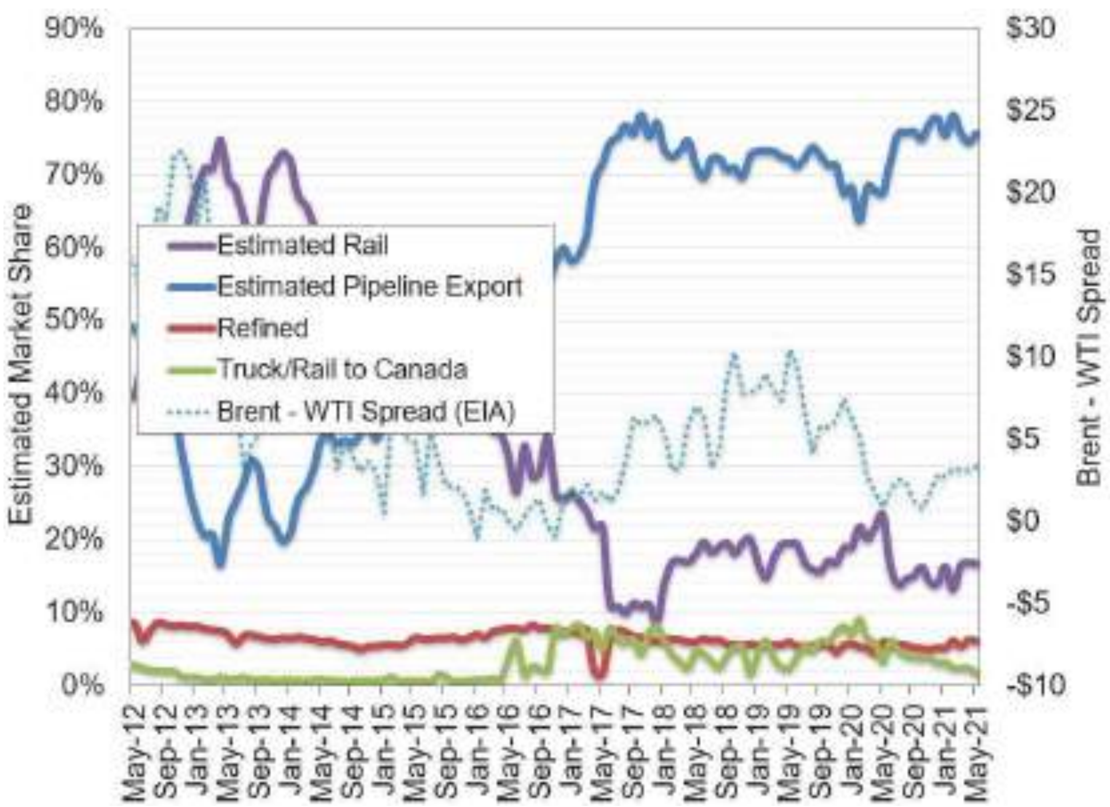
6% FLARED DUE TO CHALLENGES OR CONSTRAINTS ON EXISTING GATHERING SYSTEMS

2% FLARED FROM WELL WITH ZERO SALES

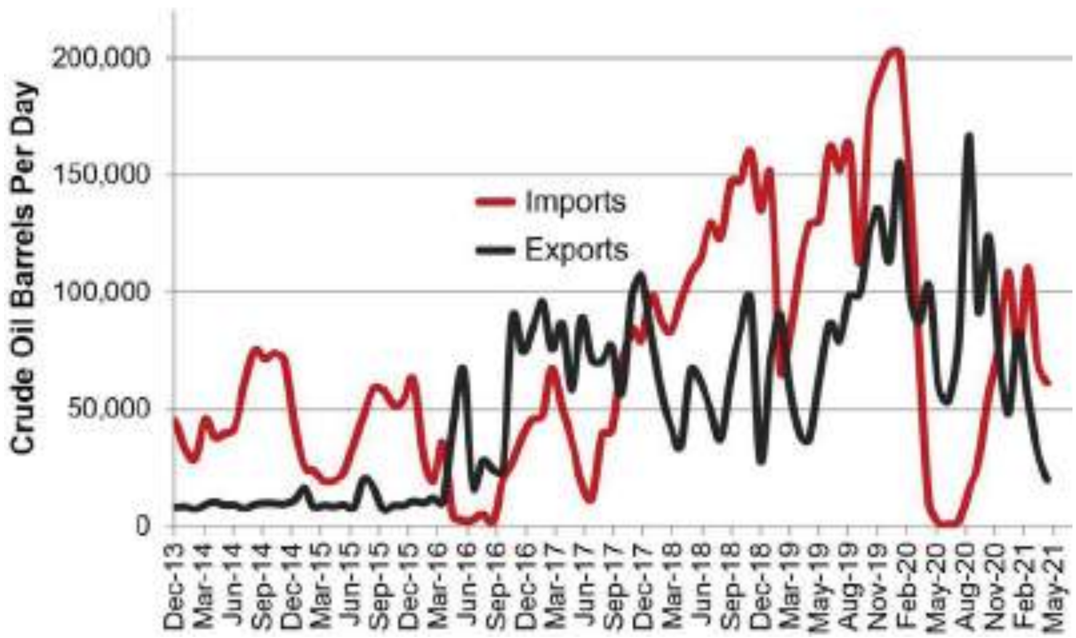
MAY 2021 NON-CONF DATA

Estimated North Dakota Rail Export Volumes

Estimated Williston Basin Oil Transportation

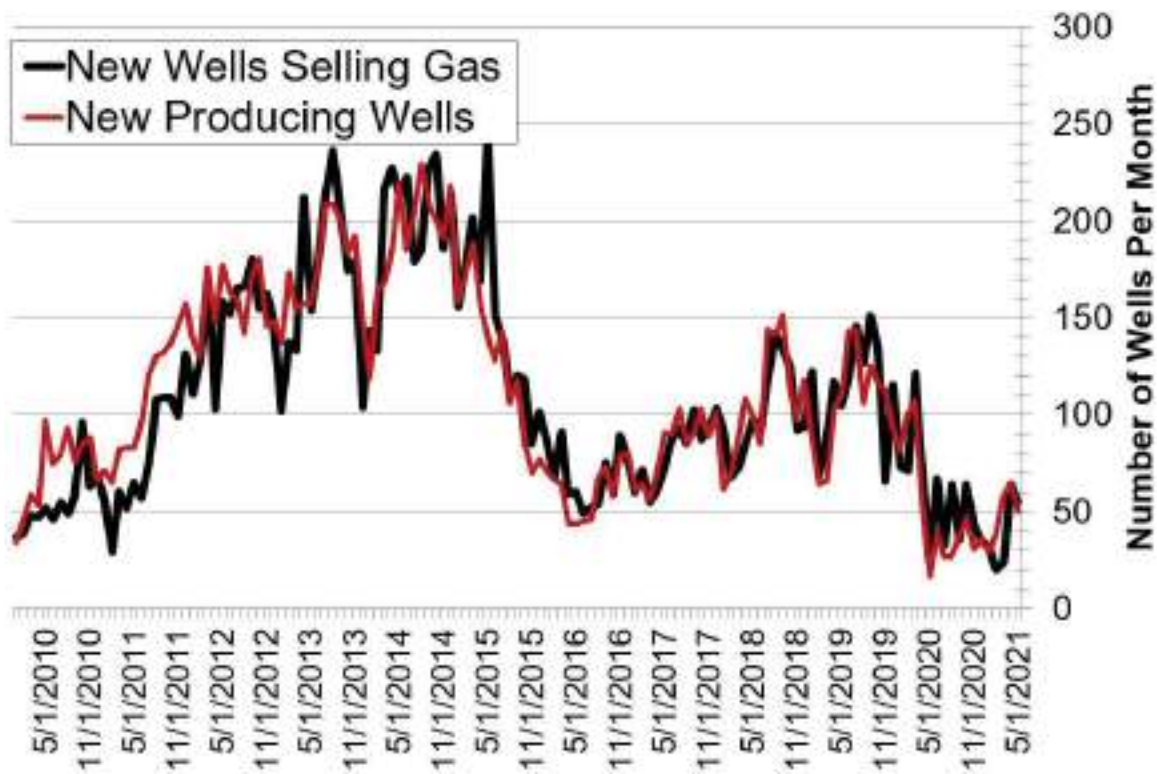


Williston Basin Truck/Rail Imports and Exports with Canada



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

New Gas Sales Wells per Month



US Williston Basin Oil Production, BOPD

2020

MONTH	ND	EASTERN MT*	SD	TOTAL
January	1,431,679	57,460	3,091	1,492,230
February	1,507,069	55,425	3,070	1,565,563
March	1,435,200	57,718	2,946	1,495,864
April	1,225,476	49,054	2,610	1,277,140
May	862,254	37,066	2,466	901,786
June	895,208	42,853	2,680	940,742
July	1,043,089	48,415	3,435	1,094,939
August	1,166,242	46,925	2,807	1,215,973
September	1,224,008	47,128	2,837	1,273,973
October	1,244,056	46,505	2,749	1,293,310
November	1,226,409	45,121	2,798	1,274,327
December	1,191,429	44,498	2,827	1,238,754

2021

MONTH	ND	EASTERN MT*	SD	TOTAL
January	1,147,375	50,115	2,874	1,200,364
February	1,083,557	47,889	2,829	1,134,275
March	1,108,906	48,265	2,744	1,159,914
April	1,123,166	38,381	2,644	1,164,191
May	1,127,517			
June				
July				
August				
September				
October				
November				
December				

** Eastern Montana production composed of the following Counties: Carter, Daniels, Dawson, Fallon, McCone, Powder River, Prairie, Richland, Roosevelt, Sheridan, Valley, Wibaux* https://rbnenergy.com/part-of-the-plan-part-3-the-st-james-crude-oil-hub-readies-for-capline-related-changes

Part Of The Plan, Part 3 - The St. James Crude Oil Hub Readies For Capline-Related Changes

Sunday, 07/18/2021
Published by: Housley Carr

In just a few months, heavy crude from Western Canada will start flowing south on the Capline pipeline from the Patoka, IL, hub to the one at St. James, LA. While the initial volumes will be modest, Capline's long-awaited reversal will provide Louisiana refineries and export terminals with easier, lower-cost access to oil sands and other Alberta production. Flipping the pipeline's direction of flow also means more changes for the St. James storage and distribution hub — one of the U.S.'s largest — which has already seen more than its share of evolution during the Shale Era. Today, we continue our Capline/St. James blog series with a look at St. James's terminals and pipelines, the Louisiana refineries they supply, and the changes coming with the Capline reversal.

Located 60 miles up the Mississippi River from New Orleans, the St. James crude oil hub has a lot going for it, including more than 36 MMbbl of storage capacity and a number of fantastic Cajun and Creole restaurants. What really sets it apart, however, is its connectivity: by pipeline, by rail, and by water. St. James's inbound pipes include the mammoth LOOP-to-Capline Pipeline (LOCAP), which can transport up to 1.7 MMb/d of crude from the 72-MMbbl crude hub in Clovelly, LA (pronounced "klow·veh·lee" if you don't want to sound like a tourist) — the receiving point for oil offloaded at the Louisiana Offshore Oil Port (LOOP), as well as for significant volumes of offshore Gulf of Mexico (GOM) production via the Mars and Endymion pipelines. Other GOM oil flows to St. James via the Bonefish and Ship Shoal pipeline systems, and crude from U.S. shale plays in Texas and the Midcontinent, comes in on the Zydeco Pipeline and Bayou Bridge (check out Louisiana Rain for maps and details on those systems). Additionally, a Department of Energy-owned pipeline leased to ExxonMobil provides bidirectional service between St. James and the Bayou Choctaw Strategic Petroleum Reserve (SPR) site, which DOE also leases to Exxon. As we said in Part 1, these inbound pipelines will soon be joined by the 40-inch-diameter Capline pipeline, which for nearly a half-century transported oil north from St. James to the crude oil hub in Patoka, IL, but is now being reversed to enable southbound flows starting late this year.

Initially, Capline's co-owners — Plains All American (with a ~54% ownership interest), Marathon Petroleum Corp. (MPC; ~33%) and BP (~13%) — had also expected the southbound Capline to receive light, U.S.-sourced crude oil via a planned extension of Plains and Valero Energy's Diamond Pipeline from the pipe's current terminus at Valero's Memphis refinery to a connection with Capline in Byhalia, MS. The proposed Diamond extension (a.k.a. the Byhalia Pipeline) ran into strong local opposition, however, and Plains announced on July 2 that the project had been scrapped.

In addition to its inbound pipelines, most of the eight St. James terminals we discussed in Part 2 (see Figure 1) have docks for receiving/unloading (and loading/sending out) crude on barges, small tankers, and, in some cases, Aframax vessels (capacity, 500-725 Mbbl). There are crude-by-rail facilities as well: the 9.9-MMbbl NuStar Energy terminal at St. James can receive and unload ~200 Mb/d from incoming trains, while the 12.5-MMbbl Plains All American terminal can handle ~140 Mb/d of crude-by-rail.

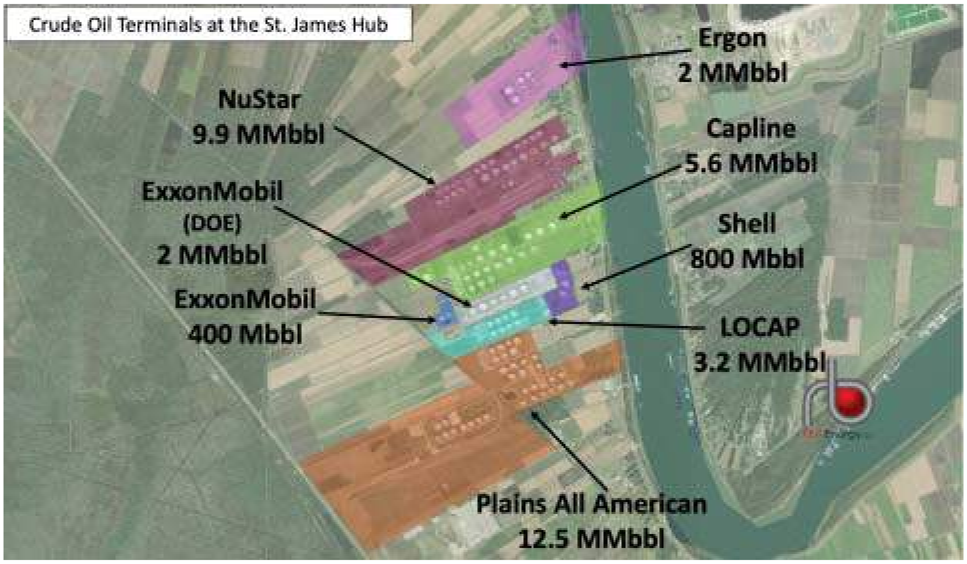


Figure 1. St. James Crude Oil Terminals. Source: RBN

Of course, all that ability to transport crude oil to St. James needs to be matched by an ability to move oil out — nowadays, mostly by pipeline to refineries in Louisiana (more on this in a moment), but also on barges and small tankers to inland refineries and onto Aframax vessels for refineries overseas. (According to RBN's Crude Voyager report, Plains' St. James terminal exported an average of 40 Mb/d of crude oil in 2020 and 39 Mb/d in the first half of 2021, while NuStar's terminal there exported an average of 15 Mb/d last year and 22 Mb/d so far this year. The report also has details on the export terminals' capacities, if you are so inclined.)

But it's St. James's role as the central crude oil storage and distribution point for many of the nine refineries in southeastern Louisiana that makes the hub so important. As shown in Figure 2, these refineries have a combined capacity of about 2.3 MMb/d, which equates to about one-quarter of the Gulf Coast's total refining capacity. (In November 2020, Shell announced the closure of its 235-Mb/d Convent refinery, which is located just across the Mississippi River from the St. James hub; Convent is not included in our count.) Geographically, the refineries supplied by terminals in St. James span from Delek US's Krotz Springs facility on the Atchafalaya River to Phillips 66's Alliance refinery in Belle Chasse, downriver from New Orleans. Capacity-wise, they range from 57 Mb/d at Placid Refining's refinery in Port Allen to 578 Mb/d at MPC's refinery in Garyville. And there could be more on the way with American Clean Energy Refining (ACER) announcing that it would build a $2 billion refinery near the Convent refinery site after a failed $1.25 billion bid to Shell for Convent. [Though not directly related to the crude demand, Chalmette is also considering a renewable diesel project at its refinery that would utilize a retrofitted hydrocracker. See Come Clean to learn why there's so much interest in renewable diesel.]

Southeastern Louisiana Refineries

	Owner	Location	Atmospheric Distillation (Mb/d)	Delayed Coking (Mb/d)
1	Marathon Petroleum	Garyville	578	103
2	ExxonMobil	Baton Rouge	520	124
3	Phillips 66	Belle Chasse (Alliance)	256	26
4	Shell	Norco	231	29
5	Valero	Norco (St. Charles)	215	86
6	PBF Energy	Chalmette	190	42
7	Valero	Meraux	125	0
8	Delek US	Krotz Springs	80	0
9	Placid Refining	Port Allen	57	0

Figure 2. Southeastern Louisiana Refineries. Sources: EIA and RBN

Outbound pipes from St. James include Energy Transfer and Alinda Capital Partners' 24-inch-diameter **Maurepas Pipeline** (aqua line in Figure 3), which runs to the Shell's 231-Mb/d Norco refinery; Marathon Pipe Line's S**t. James-to-Garyville** pipeline (maroon line), which feeds MPC's Garyville refinery; the previously mentioned Exxon DOE pipeline (dark orange line) and Crescent Midstream's Redstick Pipeline (red line) to ExxonMobil's 520-Mb/d Baton Rouge refinery and Crescent's Anchorage Pipeline (gold line) from Baton Rouge to Delek US's 80-Mb/d Krotz Springs refinery. Among the many other pipelines supplying refineries in southeastern Louisiana is Shell's Clovelly-Norco Pipeline (lime green line) from (you guessed it!) the Clovelly storage and distribution hub to Shell's Norco refinery and Valero's 215-Mb/d St. Charles refinery, also in Norco. Then there's the CAM Pipeline (light pink line) from the Clovelly hub to Phillips 66's 256-Mb/d Alliance refinery in Belle Chasse, PBF Energy's 190-Mb/d Chalmette refinery, and Valero's 125-Mb/d Meraux refinery.

As we've blogged about from time to time, there have been a number of proposals to build out Louisiana's crude oil pipeline infrastructure to facilitate the delivery of oil both to area refineries and export docks. For one, there's the ACE Pipeline project, which was proposed by a joint venture of Phillips 66 Partners, Harvest Midstream, and PBF Logistics in January 2019 and put on indefinite hold at the height of the COVID-19 pandemic. The project (dashed dark blue line) would involve the construction of a new pipeline to link St. James to Harvest's CAM Pipeline near Clovelly and enable crude to flow from St. James to the Alliance, Chalmette, and Meraux refineries.

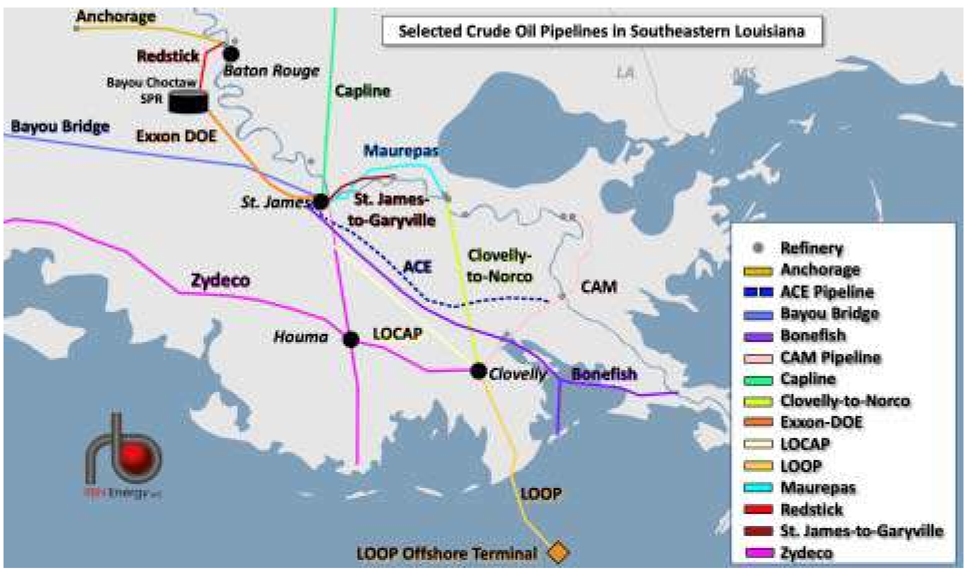


Figure 3. Selected Crude Oil Pipelines in Southeastern Louisiana. Source: RBN

Other proposals to build out southeastern Louisiana's crude oil pipeline infrastructure have been made as well, though none has advanced to date. For example, in October 2018, MPLX and Crimson Midstream unveiled the **Swordfish Pipeline** project, which would have run from St. James to Clovelly, using a combination of existing and new pipelines to transport up to 600 Mb/d (see I'm Already There for more on Swordfish). MPLX has since withdrawn from the plan, and the Bonefish Pipeline (purple line) that Crimson Midstream had planned to contribute to the Swordfish project is now controlled by Crescent Midstream, which was spun off from Crimson earlier this year. We understand that Crescent continues to pursue the possible repurposing of the Bonefish Pipeline to enable southbound flows from St. James to Clovelly.

Getting crude oil from St. James to Clovelly remains an important goal. Why? Because the Clovelly hub, with its 72 MMbbl of salt-cavern and aboveground storage capacity, not only receives oil from the LOOP offshore terminal, offshore GOM production sites, and the Zydeco Pipeline (dark pink line) from Houston, Clovelly serves as the staging point for crude exports via the LOOP Pipeline (light orange line) and the LOOP offshore terminal (orange diamond). Of course, the “simplest” way to enable crude oil flows from St. James to Clovelly would be to make the LOCAP Pipeline (yellow line) from Clovelly to St. James bidirectional. (LOCAP is co-owned by MPLX, with a 58.5% interest, and Shell, with a 41.5% stake. MPLX and Shell are also the primary owners of LOOP, with Valero holding a 3.2% stake.) Our understanding is that, with the planned reversal of Capline (bright green line) and decreasing need for northbound flows on LOCAP, making LOCAP bidirectional is becoming a real possibility. Yet another idea that’s been floated for getting crude from St. James to Clovelly would be running it through the Maurepas Pipeline to Norco and reversing the direction of flow on the Clovelly-to-Norco Pipeline.

So far, we’ve listed southeastern Louisiana’s refineries and discussed the pipelines that transport crude oil to them — and a few other related pipelines and pipeline projects too. Now, we turn our attention to the sourcing of the crude these refineries refine. As we said in our Louisiana Rain blog series, oil supplies for refineries in this region traditionally came from the offshore GOM (streams such as Mars, Thunderhorse, and Poseidon); onshore state production — Light Louisiana Sweet (LLS) and Heavy Louisiana Sour (HLS) — and imports. Given the refineries’ configurations, the average crude slate has tended to be of a medium sour quality. However, domestic shale crude production, which is of a lighter, sweeter quality, has become a larger component of the Louisiana refineries’ crude diets due to pipeline connectivity from the shale basins, including the reversal of the Zydeco Pipeline more than seven years ago.

The question before us today is, where is the heavy Western Canadian crude (such as Western Canadian Select, or WCS) that will soon start flowing south on Capline to St. James likely to end up? As we see it, most of it is likely to end up at a select subgroup of southeastern Louisiana refineries. A number of refineries there are configured to process heavy, sour crude slates — in fact, of the nine refineries listed in Figure 1, only Valero’s Meraux refinery, Delek US’s Krotz Springs refinery, and Placid Refining’s 57-Mb/d Port Allen refinery do not have delayed coking capacity. Traditionally, refineries that can process heavy crude secured the bulk of their needs from Latin American producers, including Mexico, Venezuela, and Colombia. In recent years, though, railed-in or barged-in heavy crude from Western Canada has been added to the mix (with most of those volumes flowing through St. James), and in February 2019 the U.S. halted Venezuelan imports, providing Western Canadian producers and shippers with an opportunity to increase their market share.

Initially, the volumes of heavy crude flowing south on Capline will be modest (most likely less than 150 Mb/d or even 125 Mb/d), suggesting that the pipeline’s flow reversal will not be a game-changing event. However, over the next few years, southbound flows on Capline could double or even triple — we estimate the pipeline’s potential capacity for transporting slower-moving heavy crude from Patoka to St. James at about 600 Mb/d — possibly giving heavy Western Canadian crude a stronger foothold among Louisiana refineries. It is also possible that at least a portion of the heavy crude flowing south on Capline will find its way to export docks, not only in St. James but maybe LOOP as well. In an upcoming blog, we’ll discuss the currently massive spread between light sweet crude and heavy sour Western Canadian Select, and the potential for Capline to help shrink that price gap by providing WCS producers and shippers with access to Louisiana refineries and export docks.

"Part of the Plan" was written by Dan Fogelberg and appears as the first song on Fogelberg's second studio album, *Souvenirs.* Released as a single in early 1975, it went to #31 on the Billboard Hot 100 Singles chart, making it Fogelberg's first charting single. Personnel on the record were: Dan Fogelberg (lead vocals, acoustic, electric guitar, piano), Joe Walsh (acoustic guitar, electric 12-string guitar), Russ Kunkel (drums), Joe Lala (congas, timbales), Kenny Passarelli (bass), and Graham Nash, Randy Meisner (backing vocals).

Souvenir was recorded at The Record Plant and Elektra Sound Recorders in Los Angeles during the summer of 1974, with Joe Walsh producing. Released in October 1974, the album went to #17 on the Billboard Top 200

Albums chart. It has been certified 2x Platinum by the Recording Industry Association of America. Two singles were released from the LP.

Dan Fogelberg was an American singer, songwriter, and musician from Peoria, IL. He was discovered by Irving Azoff, who sent him to Nashville to hone his skills and record his debut album, which was released in 1972. Fogelberg released 16 studio albums, three live albums, seven compilation albums, and 21 singles. Garth Brooks has stated: "Fogelberg was an artist who changed my life, who made me change where I wanted to go, and the music I wanted to play." Fogelberg died at his home in Maine in December 2007.

BAY AREA AIR QUALITY
MANAGEMENT DISTRICT

NEWS RELEASE

FOR IMMEDIATE RELEASE: July 21, 2021
CONTACT: Kristine Roselius, Air District, 415.519.5419
Beth Willon, Communications Director for Supervisor Cindy Chavez, 408.660.5174

Air District strengthens refinery rule to reduce particulate emissions from fluidized catalytic cracking units

Reducing emissions from FCCUs is a critical step to control health-threatening air pollution

SAN FRANCISCO – The Bay Area Air Quality Management District's Board of Directors today adopted amendments to Regulation 6, Rule 5: Particulate Emissions from Refinery Fluidized Catalytic Cracking Units to further reduce particulate matter emissions from petroleum refineries. The rule is now the most health-protective and stringent regulation of its kind in the country.

The Air District adopted Rule 6-5 in 2015 to minimize particulate matter emissions from Fluidized Catalytic Cracking Units, or FCCUs, which are the largest single source of particulate matter emissions at refineries and some of the largest individual sources of particulate matter in the Bay Area. The new amendments impose stricter FCCU control requirements to reduce health-threatening air pollution.

"Today's vote by the Air District Board of Directors is a victory for every Bay Area resident, particularly those living in communities surrounding refineries as well as the refinery workers regularly exposed to harmful particulate pollution," said Santa Clara County Supervisor Cindy Chavez, who is chair of the Air District Board of Directors. "We are committed to protecting the health of both refinery workers and neighbors and look forward to implementing this landmark protective rule with Chevron and PBF."

"As scientific understanding continues to advance on the harmful health effects of particulate matter pollution, stricter controls are necessary to protect those who live and work in refinery communities," said Jack Broadbent, executive officer of the Air District. "The Air District is committed to reducing air pollution exposure in impacted areas and these amendments are a necessary and critical step toward controlling the most significant air pollution health hazard in the Bay Area."

The region-wide health benefits of attaining and maintaining compliance with ambient air standards for particulate matter are significant. Analysis by Air District staff found that PM2.5, which is emitted from FCCUs, is the primary health threat from air pollution in the Bay Area, particularly in terms of premature mortality. The Air District has calculated that for the million people most affected, exposure to particulate matter from the Chevron refinery in Richmond increases mortality by an average of up to 11.6 deaths per year and an average of up to 6.3 deaths per year from the PBF Martinez refinery.

Rule 6–5 applies to the four refineries in the Bay Area that have FCCUs. One of these refineries already controls emissions from their FCCU with a wet gas scrubber. The other refineries may decide to install wet gas scrubbing systems to comply with the new amendments. More information regarding Rule 6–5 is available at baaqmd.gov/reg6rule5.

The Bay Area Air Quality Management District is the regional agency responsible for protecting air quality in the nine-county Bay Area. Connect with the Air District via Twitter, Facebook and YouTube.

# # #

Air District Communications Office
375 Beale Street, Suite 600, San Francisco, CA 94105
Air District Homepage | *News Releases*

Chevron Sees $1.5b Cost to Comply With Bay Area Emission Rule
2021-07-21 23:58:17.303 GMT

By Gerson Freitas Jr.
(Bloomberg) -- New refinery emission rule approved by California's Bay Area Air Quality Management District is "so flawed" that Chevron will investigate its legal options, company spokesman Sean Comey said by email.
* Chevron sees capital costs associated with a wet gas scrubber installation at $1.5b, well above a $241m-$579m estimate by the District
* EARLIER: California's Bay Area Sets Tougher Refinery Pollution Controls
* MORE: PBF Energy Falls on Tougher Bay Area Pollution Controls

To contact the reporter on this story:
Gerson Freitas Jr. in New York at gfreitasjr@bloomberg.net
To contact the editors responsible for this story:
Simon Casey at scasey4@bloomberg.net
Rob Verdonck

https://www.argusmedia.com/en/news/2237347-exxonmobil-shut-norway-slagen-refinery-in-june

ExxonMobil shut Norway Slagen refinery in June

Published date: 23 July 2021

ExxonMobil has told *Argus* that its stopped operations at its 120,000 b/d Slagen refinery in Norway in June.

The company said in April that it would permanently shut the refinery over the summer, saying continued operation "is not economically viable over the long term" because of "strong competition, evolving regulatory measures, and falling demand."

Around 60pc of Slagen's products were exported. Its closure leaves state-controlled Equinor's 200,000 b/d Mongstad plant as Norway's only refinery.

Slagen is the fifth European refinery to halt completely since the Covid-19 pandemic, bringing the lost crude distillation capacity to more than 600,000 b/d. TotalEnergies halted its 93,000 b/d Grandpuits refinery in France, and will convert it to process pure renewable fuels. Portugal's Galp and Finland's Neste have permanently stopped their respective 110,000 b/d Porto and 55,000 b/d Naantali refineries to focus on products imports.

Trading firm Gunvor has long-term mothballed its 115,000 b/d Antwerp refinery, and UK-Chinese Petroineos has done the same with one crude distillation unit (CDU) at the 210,000 b/d Grangemouth refinery. Gunvor has also permanently stopped both CDUs at its 80,000 b/d Europoort refinery in Rotterdam, though it continues to run secondary units.

Europe's refineries have for years been contending with competition from producers in the Middle East and Asia-Pacific, where capacity continues to grow rapidly, while local fuel demand growth slows. Gasoline and diesel vehicles comprised just 62pc of new car sales in the EU in the second quarter of this year, down from more than 80pc a year earlier.

By Benedict George

https://www.npd.no/en/facts/news/Production-figures/2021/production-figures-june-2021/

Production figures June 2021

21/07/2021 Preliminary production figures for June 2021 show an average daily production of 1 883 000 barrels of oil, NGL and condensate,

Total gas sales were 7.9 billion Sm^3 (GSm^3), which is a decrease of 0.8 GSm^3 from the previous month.

Average daily liquids production in June was: 1 674 000 barrels of oil, 196 000 barrels of NGL and 12 000 barrels of condensate.

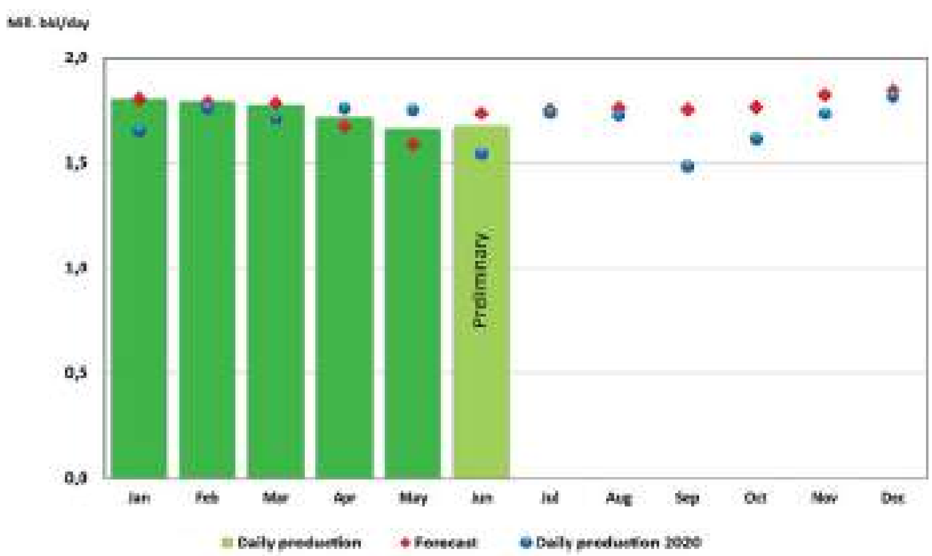
Oil production in June is 3.6 percent lower than the NPD's forecast, and 0.4 percent higher than the forecast so far this year.

The main reasons that production in June was below forecast is technical problems and maintenance work on some fields.

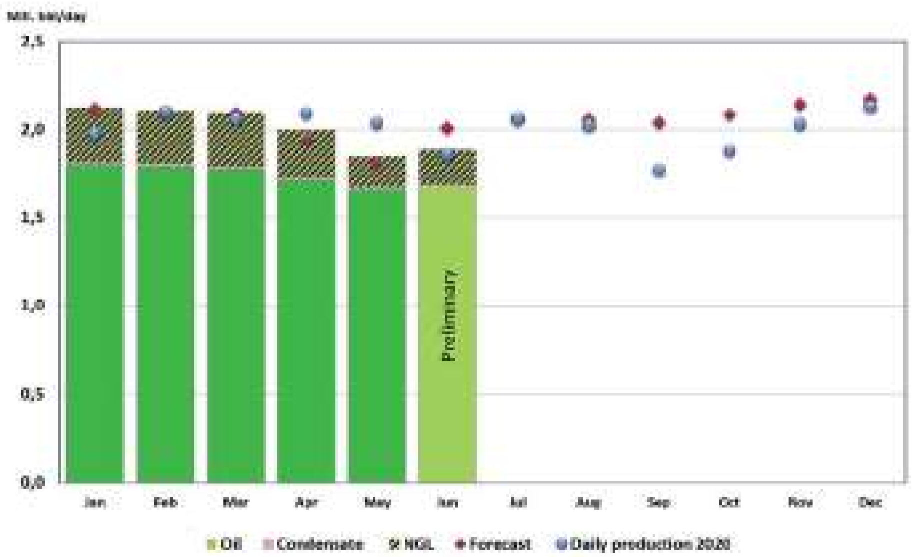
Production June 2021

		Oil	Sum liquid	Gas	Total
		mill bbl/d	mill bbl/d	MSm³ /d	MSm³ o.e/d
Production	**june 2021**	**1,674**	**1,883**	**264,3**	**0,564**
Forecast for	June 2021	1,736	2,010	285,1	0,605
Deviation from forecast		-0,062	-0,127	-20,8	-0,041
Deviation from forecast in %		-3,6 %	-6,3 %	-7,3 %	-6,8 %
Production	May 2021	1,662	1,846	280,5	0,574
Deviation from	May 2021	0,012	0,037	-16,2	-0,010
Deviation in % from	May 2021	0,7 %	2,0 %	-5,8 %	-1,7 %
Production	June 2020	1,543	1,857	279,7	0,575
Deviation from	June 2020	0,131	0,026	-15,4	-0,011
Deviation in % from	June 2020	8,5 %	1,4 %	-5,5 %	-1,9 %

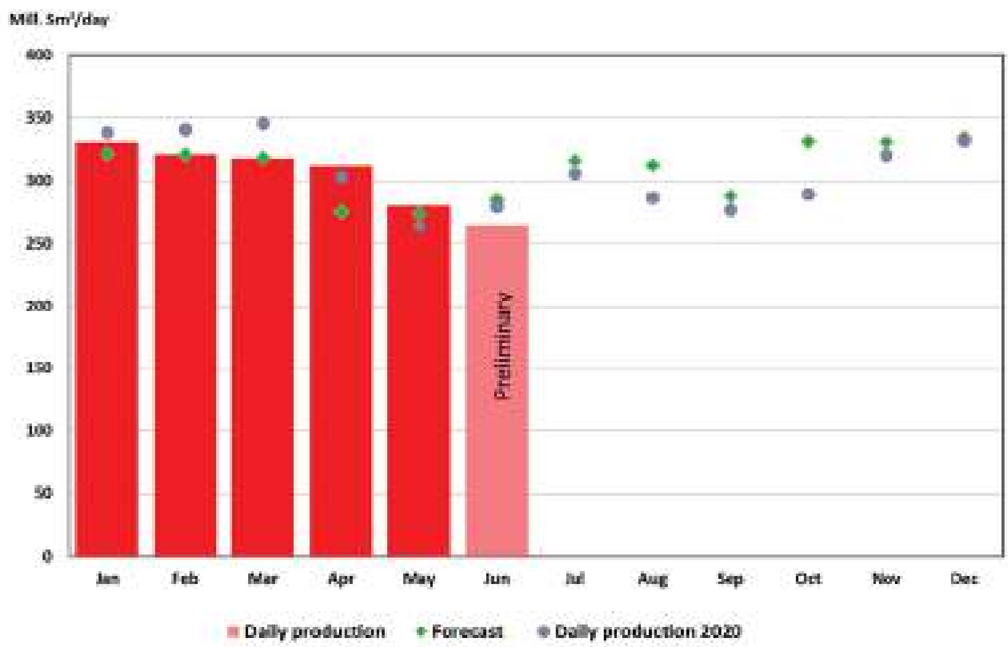
Oil production 2021



Liquid production 2021



Gas production 2021



The total petroleum production for the first six months in 2021 is about 112.8 million Sm^3 oil equivalents (MSm^3 o.e.),

broken down as follows: about 49.9 MSm^3 o.e. of oil, about 7.8 MSm^3 o.e. of NGL and condensate and about 55.1 MSm^3 o.e. of gas for sale.

The total volume is 2.4 MSm^3 o.e. lower than in 2020.

https://www.npd.no/en/facts/news/general-news/2021/high-activity-level-on-the-norwegian-shelf/

High activity level on the Norwegian shelf

21/07/2021 The activity level on the Norwegian continental shelf (NCS) has been high in the first six months of the year – despite the Covid situation. Eight discoveries have been made, production remains high, and many new development projects are on the drawing board.

During the first six months (as of 30 June), a total of 17 wildcat wells have been completed on the NCS, resulting in eight discoveries. The size of these discoveries is still uncertain, but estimates indicate that, in total, they could amount to more than double the volume of oil and gas contained in the Goliat field in the Barents Sea (estimated reserves for Goliat is more than 31 million standard cubic metres of oil equivalent).

The discoveries have been made in mature areas, near other fields and infrastructure. Utilising the existing infrastructure could allow cost-effective development of the new discoveries, which would then represent significant value creation. New discoveries have been made in all three sea areas, the North Sea, the Norwegian Sea and the Barents Sea.

Overview – discoveries first half of 2021

Well	Name	Resource growth, M Sm³ o.e.	Low-High estimate, M Sm³ o.e.
25/8-20 B and S	King and Prince	11.5	9 - 14
34/6-5 S	Garantiana West	2.5	1.3 – 3.6
6507/4-2 S	Dvalin Nord	18.0	11 - 25
15/12-25	Jerv	0.0	Presumably not recoverable
16/4-13 S	D segment	1.0	0.5 – 1.4
7220/7-4	Isflak	6.5	5 - 8
31/1-2 S	Røver Nord	9.0	7 - 11
31/2-22 S	Blasto	15.5	12 - 19
Total expected resource growth		63,9	

Table 1: Overview expected resource growth first half 2021

Exploration is key

The Norwegian Petroleum Directorate (NPD) also expects a high level of exploration activity in the time ahead. According to the NPD’s forecasts at year-end around 40 exploration wells will be drilled this year, while 31 exploration wells were spudded in 2020.

“Exploration has enormous significance for long-term value creation on the shelf. The addition of oil and gas resources from new discoveries, like we have seen so far this year, is necessary to prevent a sharp decline in petroleum industry activity after 2030. Without new discoveries, production could fall by more than 70 per cent in 2040 compared with 2020", says Torgeir Stordal, director of Technology and coexistence at the Norwegian Petroleum Directorate.

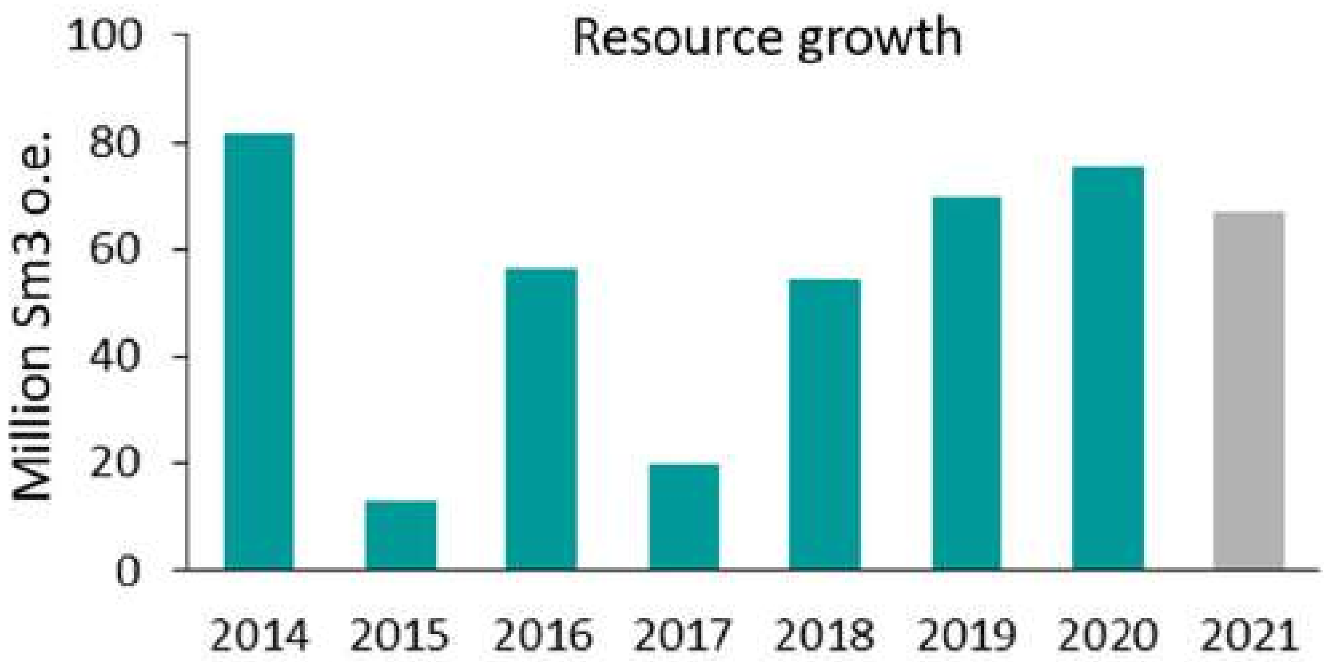


Figure 1. Resource growth first half of 2021 compared with previous whole years.

"Exploration is also important for the fields. Phasing in new discoveries to existing fields provides a better foundation for a further commitment to improved recovery and extended production. This is a link between exploration and increased value creation from the fields," says Kalmar Ildstad, director of Licence management at the Norwegian Petroleum Directorate.

New exploration acreage

In January, 30 companies were offered a total of 61 new production licences in APA 2020. Once again, the companies exhibited great interest in gaining access to new exploration acreage in this round. APA 2021 was announced in June, with an application deadline of 8 September 2021.

In June, seven companies were offered ownership interests in a total of four production licences in the 25th licensing round on the Norwegian shelf. One of these four production licences is in the Norwegian Sea and three are in the Barents Sea. Two of these are additional acreage for existing production licences.

Petroleum production

Total petroleum production in the first six months is 112,8 million standard cubic metres (Sm^3) of oil equivalent (o.e.).

Of this, around 49,9 million Sm^3 is oil, 55,1 billion Sm^3 is gas and 7,8 million Sm^3 is NGL and condensate.

Production in the first half of 2021 is 2,4 (Sm^3 o.e.) less than the corresponding period in 2020.

Read more: Production figures June 2021

During the first half of 2021 a total of 94 development wells have been , which is somewhat higher than during the same period last year (86). Drilling wells is the single most important measure to increase production.

New development plans

As of now, 91 fields are producing on the NCS, including Martin Linge which came on stream at the very end of June, and more are planned. The authorities have received two new development plans in the first six months. These plans relate to Kristin in the southern Norwegian Sea, and the Kobra East and Gekko discoveries in the Alvheim area in the North Sea.

The authorities have also approved three new plans for development and operation (PDOs). These relate to Breidablikk in the North Sea, Northern Lights´ CO_2 storage in the Longship project, as well as a new plan for power from shore to the Troll field in the North Sea.

Ten fields are under development on the Norwegian shelf. The licensees on the shelf are preparing additional projects which will yield new production.

Significant investments

The Norwegian shelf is about to see a wave of projects, and there are good prospects for high activity and production over the next few years. According to the Norwegian Petroleum Directorate's figures, there are as many as 50 projects where the licensees are aiming for investment decisions by the end of 2022.

All in all, these projects represent more resources than one and a half Johan Sverdrup fields (estimated reserves for Johan Sverdrup is more than 428 million standard cubic metres of oil equivalent). Total estimated investments are around NOK 380 billion.

"These projects would most likely have been implemented regardless, but the temporary amendment to the Petroleum Tax Act have probably led to some acceleration in certain projects. Progress in time-critical projects is another positive factor. There may be postponements, but we see a strong willingness to submit development plans by 2022", says Ildstad.

Seabed minerals

The Ministry of Petroleum and Energy's proposed impact assessment program for mineral activity on the seabed was submitted for consultation in the first part of 2021. Work on the baseline reports for the impact assessment is well under way.

At the same time, the Norwegian Petroleum Directorate continues to collect data in the Norwegian Sea.

In this area the NPD conducted its own expedition in autumn 2020. A total of 62 samples from this expedition have been fully analysed and the results reveal in part high zinc and copper levels.

The NPD will participate in five expeditions over the course of the summer and autumn months, one under our own direction and four in cooperation with university and research communities.

CONTACT

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

Bloomberg @TheTerminal

Saudi Prince of Oil Prices Vows to Drill 'Every Last Molecule'
2021-07-22 04:00:12.387 GMT

By Javier Blas
(Bloomberg Markets) -- The Boeing 767 banked over the Red Sea, turning east into Saudi Arabia. A commercial version of the plane can carry about 260 passengers. Inside this one, Saudi Energy Minister Prince Abdulaziz bin Salman and a dozen or so aides were heading home from a tumultuous meeting at OPEC's headquarters in Vienna the day before.
For most of the journey, the jetliner had followed its expected route over Eastern Europe, the Mediterranean, and Egypt. It was a path that Abdulaziz had flown scores of times. As oil minister since 2019 and a royal understudy before that, he'd attended almost every OPEC meeting over the past 35 years. But this flight, on March 7, 2020, wasn't typical. What occurred afterward wasn't, either.
The decisions Abdulaziz took over the next 24 hours exposed a new Saudi oil policy—bolder, less constrained by Washington, defiant of a growing global consensus on climate change, and more centrally controlled by the royal family, including one of his half-brothers, Crown Prince Mohammed bin Salman.
They also reflected what Abdulaziz sees as his destiny: to ensure that the last barrel of oil on the face of the Earth comes from a Saudi well. As he said in June during a private event organized by Bank of America Corp., according to a person familiar with the meeting, "We are still going to be the last man standing, and every molecule of hydrocarbon will come out."
All of this has huge implications for the world's energy markets at a time when, in erecting a fortress to safeguard oil, Abdulaziz and Saudi Arabia seem to be on the wrong side of history. Abdulaziz, the first member of the royal family to be the kingdom's energy minister, is the most important single person in the oil market today. As influential in global economic terms as some central bankers, he has repeatedly taken bold, successful steps to control the markets, manage the flow of oil supplies, and shore up prices.
But a rancorous OPEC+ meeting in July showed just how difficult it's going to be for Abdulaziz to consistently get his way in an era when oil-producing nations—their self-interests often in conflict—are contemplating a future of declining oil consumption. By the time OPEC+ ministers convened over videoconference, resurgent demand had already pushed crude prices up 50% this year. When the talks collapsed, oil prices jumped to the highest level in more than six years.

It took Abdulaziz two weeks of behind-the-scenes diplomacy to resolve the impasse, ultimately clinching a deal that followed a classic blueprint of his: Everyone involved saved face, even if some of the targets for future production stretched credulity. “Consensus-building is an art,” he told reporters after the meeting, coyly declining to elaborate. “Why should I divulge it? This is an art, and we keep it between ourselves. We call it a state secret.”

QuickTake: How OPEC+ Averted a Renewed Crisis in the Oil Market
Abdulaziz’s time as energy minister since his appointment in September 2019 has been perhaps the most convulsive and consequential period in the history of the Saudi oil industry, overshadowed only by the first and second oil crises in the 1970s. Abdulaziz didn’t agree to an on-the-record interview for this article. Bloomberg Markets reconstructed his tenure as minister—and his rise to get there—through interviews with diplomats, consultants, traders, and current and former Saudi, OPEC+, and U.S. officials.

After the OPEC+ meeting in Vienna in March last year, Abdulaziz and his retinue boarded their waiting jet—registration number N767A emblazoned on its tail—and took off. An oil world geek monitoring the plane’s radar signature on a real-time aircraft tracking website would have known something was amiss. The plane didn’t land at Riyadh, the capital, where the energy ministry and Abdulaziz’s residence are located. It continued flying over the Saudi desert, the bleakness occasionally broken by gas flares down on the oil fields, and then on toward the Persian Gulf coastline.

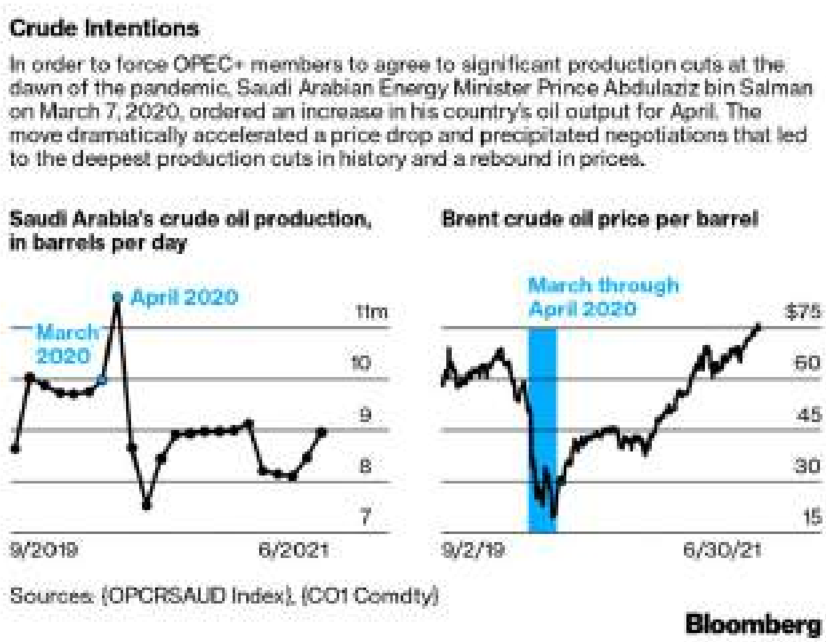
At 3:35 p.m. that Saturday, the jet landed at King Abdulaziz Air Base, a military complex near Dhahran in the heart of the kingdom’s petroleum industry. Abdulaziz headed straight to the headquarters of Saudi Aramco, the national oil company. The surprise detour to Dhahran was prompted by what had happened the day before in Vienna. At a special OPEC+ meeting, Saudi Arabia and Russia (the +, as it isn’t an OPEC member) clashed over how to respond to the coronavirus pandemic that was beginning to spread across the globe.

Moscow, anxious to avoid reducing output, preferred a wait-and-see approach. Riyadh wanted to slash production—immediately. Through their association with refineries around the world, the Saudis had recognized early on that the Covid-19 outbreak was going to cause economic havoc, and they wanted to prevent a crash in oil prices.

The meeting ended without agreement. Ominously, Alexander Novak, then the Russian oil minister, said to reporters afterward, “Given today’s decision, all OPEC+ countries from April 1 have no obligations to cut output.” Now all eyes were on Abdulaziz. Asked if Saudi Arabia would follow Russia’s lead, he told reporters, “I’ll keep you wondering.”

Not for long. The drive from the airfield to the Aramco campus takes about 15 minutes. Abdulaziz's entourage would have gone past Dammam No. 7, known as the "Prosperity Well," because the day it struck oil in March 1938 marked the commercial discovery of petroleum in Saudi Arabia.

Over the years, the Saudis had come to believe they must always act in concert with other oil producers and not unilaterally. Now, Abdulaziz had decided to suspend that rule, if only for a short time, to make a point—we're in charge of managing the oil market—and to teach a lesson to Russia and its president, Vladimir Putin, whose power depends in part on his country's oil revenue.
Once inside Aramco's main administration building, Abdulaziz did something shocking and counterintuitive for someone who'd indicated in Vienna that he favored production curbs: He ordered the world's biggest energy company to ramp up production to maximum levels. The next day, with the oil market closed for the weekend, Saudi Arabia launched an all-out price war. It announced it would begin pumping 12 million barrels a day, an increase of more than 20% over the month before.



For the energy markets, this was the equivalent of a nuclear first strike. To push such huge volumes onto the market, Aramco slashed the price of its oil, offering refiners the largest discounts ever. The price cuts were particularly big for European oil refineries, hitting Russia's traditional market the hardest.
When the oil market reopened on Sunday evening, Brent crude, the global benchmark, plunged almost 25% within seconds—the biggest one-day fall since January 1991, during the Persian Gulf War. The carnage extended beyond the oil market.

The MSCI World Energy Sector Index—a basket of leading petroleum companies, including Exxon Mobil, Chevron, Royal Dutch Shell, Total, and BP—plummeted almost 19%, its biggest-ever one-day drop, erasing $330 billion in share value. Over the next week, the index lost $400 billion more.

Panic gripped the White House. Breaking with decades of close cooperation, Saudi Arabia hadn't informed Washington of its production bombshell, which caught the CIA and U.S. diplomats in Riyadh by surprise, according to Victoria Coates, a White House deputy national security adviser at the time. The administration of President Donald Trump, which saw the U.S. oil industry as a strategic and political asset, was in shock. "It was uncharted territory," says Coates.

The oil industry and the countries that depended on it were staring into an abyss of collapsing prices. That, of course, included the Saudis, who'd just shown they were ready to shoot themselves in the foot to get production and prices back to what they deemed sustainable levels. The scenario, as risky and cynical as it was, was unfolding just as Abdulaziz intended: Create enough pain to get everyone around the negotiating table—quickly.

Enter Trump. During the first week in April, he gathered top U.S. oil executives at the White House. "We'll work this out, and we'll get our energy business back," he said. "I'm with you 1,000%." Trump orchestrated a series of phone calls, including a critical conversation with Putin and Saudi Arabia's King Salman—bringing together three countries that produced more than 40% of the world's oil at the time.

On April 12, after 36 days of hostilities, Riyadh and Moscow agreed to the deepest oil production cuts in history, calming the markets and torpedoing Russia's refusal to curb output a month earlier.

Trump's intervention was a gift to the Saudis. As a presidential candidate, he'd sometimes criticized the regime, which he said treated women as "slaves" and "kills gays." But as president, he'd fostered cozy relations with the world's biggest purchaser of U.S. arms. Riyadh was the first stop on his first foreign trip as president. He supported the kingdom's war in Yemen. He sided with Saudi Arabia after his own intelligence community said Crown Prince Mohammed was complicit in the murder of Saudi-born U.S. resident and journalist Jamal Khashoggi in 2018.

And now Trump had facilitated the oil deal the Saudis wanted. "What happened in April is helping us," Abdulaziz said of the pact via video link at the annual Robin Hood Investors Conference last October, according to a person familiar with what was said. The price war, Abdulaziz said, "is a good example [of] what free markets would do if the commodity market is not attended to." The deal had brought order to the disarray that followed the OPEC+ breakdown in Vienna.

Abdulaziz spent the past year trying to keep things that way, but July's OPEC+ bust-up laid bare the obstacles in front of him. At the meeting, Abdulaziz found Saudi dominance under attack again. This time the obstreperous member was Saudi Arabia's neighbor, the United Arab Emirates.

Backed by most OPEC+ members, including Russia, Abdulaziz wanted the group to agree to graduated production increases not only over the next few months but also, for the sake of stability, until the end of 2022. "The extension puts lots of people in their comfort zone," Abdulaziz told Bloomberg TV on July 4. But UAE Energy Minister Suhail Al Mazrouei opposed the longer extension as "unnecessary to take now."

Resurgent demand had already pushed up crude prices this year by the time OPEC+ convened. When the talks collapsed, blocking a supply increase, the standoff threatened to turn into a conflict as damaging as last year's price war. West Texas Intermediate crude reached $76.98 a barrel, the highest price since November 2014. With his diplomatic maneuvering, Abdulaziz managed to avert a worsening spiral—for the time being.

In his Bloomberg TV interview, Abdulaziz had said, "If I'm going to be called something, I would like to be 'volatility buster.' " And yet once again, representing OPEC+'s largest producer, here he was, fighting to retain Saudi control of the market and preserve the "volatility buster" reputation he'd tried to craft for himself.

In January 2020, Abdulaziz was making his way through a bustling corridor at the World Economic Forum in Davos, Switzerland, when a television reporter and camera crew caught up with him. He had just wrapped up an appearance on a panel discussion titled "The Future of Fossil Fuels." The journalist, Joel Hills of London-based ITV News, wasn't interested in asking the oil minister about oil. He wanted to talk to Abdulaziz about a report that morning in the Guardian newspaper that claimed Crown Prince Mohammed had authorized the hacking of a mobile phone belonging to Amazon.com Inc. founder Jeff Bezos.

Abdulaziz had no intention of being drawn into any of the many controversies surrounding his half-brother. Hills persisted. Dapper in a chocolate-colored three-piece suit and silk pocket square, the minister, usually unflappable and unfailingly courteous, said the question was "a mockery and a joke" and called Hills "stupid." As the reporter followed him, Abdulaziz grabbed the microphone. Judging from the video footage, he seemed about to hand the mic to an aide but thought better of his actions and handed it back to Hills, saying, "I don't have to explain to you."

In public, Abdulaziz has never commented on accusations of human-rights abuses lodged against Mohammed bin Salman since his half-brother was anointed crown prince by King Salman in 2017. He anchors his public persona strictly within the confines of his oil portfolio. As he said at the outset of his confrontation with Hills, “No, don’t ask that. I am the minister of energy.”

In Saudi Arabia, now more than ever before, oil is a family business. Two years after the king turned the day-to-day running of Saudi affairs over to the crown prince in 2017, he turned the energy empire over to Abdulaziz. For the first time, the oil portfolio was in the hands of a member of the royal family and not a technocratic outsider.

“He understands power better than anyone else. And oil is about power.”

Abdulaziz bin Salman Al Saud was not just any member of the House of Saud, which comprises about 15,000 people. He’s the fourth-oldest son of King Salman. At 61, he’s considerably older than his powerful half-brother the crown prince, who turns 36 in August. He’s also a half-brother of Prince Khalid bin Salman, who’s deputy defense minister and a younger full brother of Mohammed.

Given the veil of secrecy that keeps prying eyes away from the House of Saud, it’s difficult for an outsider to know if Abdulaziz hatched the price war idea himself in 2020. Recent history suggests that very little happens in Saudi Arabia without the direction or input of Crown Prince Mohammed. Whatever the truth, Abdulaziz embraced the tactic as his own.

“He’s the ultimate inside man,” says Helima Croft, global head of commodity strategy at RBC Capital Markets. Croft, a former Central Intelligence Agency analyst, has known Abdulaziz for many years. “He understands power better than anyone else,” she says. “And oil is about power.”

Saudi Arabia’s power—and therefore Abdulaziz’s—are under threat as the world seeks to move away from oil and other fossil fuels. Beneath the kingdom’s desert there are about 265 billion barrels of oil, worth almost $20 trillion at this summer’s prices. It’s a massive prize, but one that may be worthless someday if the global economy figures out how to keep churning without oil.

“Saudi Arabia is not in a comfortable position,” says Karen Young, a senior fellow at the Washington-based Middle East Institute and director of its Program on Economics and Energy. “There will be customers for oil in 10 and 20 years from now. But [every oil producer] is going to be competing for a smaller and smaller number of buyers.”

One day in June 1987, Abdulaziz, then 27, was ensconced in Room 332 of the Vienna Marriott Hotel, getting ready to attend his first OPEC meeting. His decades-long ascent in the Saudi oil

hierarchy had begun.
Abdulaziz was a very junior member of the Saudi delegation headed by Oil Minister Hisham Nazer, a nonroyal technocrat who'd been educated as an undergraduate and graduate at the University of California at Los Angeles. The official record of the meeting put Abdulaziz at No. 8 in the delegation's hierarchy.
His early days were instructive. In 1987, Saudi Arabia was ending a price war. From 1980 to 1986, Riyadh had cut production to keep oil prices high even as other OPEC members kept pumping away. Ultimately, with Saudi production plunging so much that it couldn't meet domestic consumption, Riyadh reversed course, flooding the market and crashing prices.
As was the case with the price war that Abdulaziz would preside over in 2020, the effects of the 1980s campaign were felt around the globe: from Texas and Oklahoma, where economies slumped, to Moscow, where the damage played a role in accelerating the demise of the Soviet Union, whose hard currency needs relied on high oil prices.
The lessons weren't lost on Abdulaziz. "The Saudis determined never again to cut production alone," says David Rundell, a U.S. diplomat who spent 15 years in Saudi Arabia, including a stint as chief of mission at the embassy in Riyadh. "And this has been their guiding principle ever since."
Were Abdulaziz not a royal, say many of his critics and admirers alike, he'd be like any other extremely well-turned-out technocrat. As a young Saudi prince, he soon found an interest in academia and oil. From Riyadh he moved to Dhahran, where he studied at the King Fahd University of Petroleum & Minerals, the elite school that's educated most of the engineers who today run Aramco.
After leaving in 1985 with an undergraduate degree in industrial management and a master's in business administration, he ran an economic think tank associated with the university for a while. Shortly after marrying Sara bint Khalid bin Musa'ad, he decided to join the government, against the initial advice of his father.
In 1995, Nazer, the oil minister he had accompanied to Vienna in 1987, was replaced by Ali al-Naimi. Abdulaziz, aided by his royal imprimatur, effectively became al-Naimi's deputy and then performed much the same role for the next oil minister, Khalid Al-Falih, from 2016 until he landed the top job himself.
These days, Abdulaziz's 35 years of experience set him apart from his peers who come and go at OPEC headquarters in Vienna. "He knows markets inside out," says Jeff Currie, head of commodities research at Goldman Sachs Group Inc. "He's like none of the other oil ministers."
"I come with baggage" is how Abdulaziz put it jocularly when he spoke to JPMorgan Chase & Co. clients earlier this year via a video link, according to a person familiar with what was

said. “I have a lengthy career, and I have seen it all.”
It was a tense gathering. In September last year, Abdulaziz was chairing the energy ministers’ meeting of the Group of 20. Environmentalist groups have long accused Saudi Arabia of obstructing global efforts to reduce carbon emissions. Over the past couple of decades, the Saudis have moved from climate change denial to supporting the historic 2016 Paris Agreement—but never forfeiting the protection of their valuable resource. The G-20 forum was a chance for Riyadh to get a grip on the diplomatic maneuvering ahead of this year’s most important climate change conference, the COP26 gathering in Glasgow, Scotland, in November.
“We are sitting on a huge amount of hydrocarbon resources, and we want to bring it to better use.”
Hours of talks over video link went by, but the ministers were unable to come to an agreement on what their communiqué would say. European ministers wanted a greener statement; Saudi Arabia didn’t. Finally, Abdulaziz got his way, arguing in effect that if they ended the meeting with no statement at all, they’d all look bad.
The communiqué that emerged endorsed several of Saudi Arabia’s pet fixes to the climate crisis. One is to employ carbon sequestration, even though the technology hasn’t proved to be commercially viable. Another, with no targets or timelines attached to it, is what the Saudis call “the circular carbon economy,” built around “the four Rs”—the reduction, reuse, removal, and recycling of carbon to cut emissions.
What these measures have in common is that they make sure oil will live to die another day. “We are sitting on a huge amount of hydrocarbon resources,” Abdulaziz said at the meeting, “and we want to bring it to better use.”
The Middle East Institute’s Young says that Riyadh is moving too slowly into renewable energy, where the kingdom has a natural advantage in solar power thanks to its sun-scorched desert. “Nothing happens overnight,” she says. “[But] when you look at the results so far, it’s tiny.”
One of Abdulaziz’s predecessors as oil minister, the late Sheikh Ahmed Zaki Yamani, issued an oft-quoted warning: “The Stone Age didn’t end for lack of stone, and the Oil Age will end long before the world runs out of oil.” But he sounded this alarm more than 40 years ago, and the world remains as dependent on oil now as it was then.
Yamani-like gloomy prognoses are anathema to Abdulaziz, whose custodianship of his country’s reserves suggests he’s counting on the vaunted global energy transition to take a long, long time.

A few years ago, the International Energy Agency came out with one of its regular bulletins about how the growth in oil

demand is slowing. “If I had to be concerned with IEA projections,” Abdulaziz said in Abu Dhabi during a public forum at the 24th World Energy Congress in September 2019, “I probably [would] be [on] Prozac all the time.”
More recently, the IEA released a report calling for the cessation of all new investment in fossil fuels as a means of avoiding global warming. Speaking to journalists at an OPEC+ news conference in June, Abdulaziz described the document as “a sequel of the La La Land movie.”
Where Abdulaziz saw fantasy, the climate activist Greta Thunberg saw the Saudis in retreat. “Wow,” she said on Twitter on June 1. “We’re clearly witnessing the beginning of the end of the fossil fuel era. They’re starting to panic. Let’s speed up the process.”
At some point, the demand for petroleum will reach a tipping point. The signs are everywhere, from the explosion of renewables and the increased adoption of electric vehicles to the readmittance of the U.S. to the Paris Agreement under President Joe Biden and the growing number of fossil fuel-shy investors staying away from oil companies.

That’s one school of thought. The Saudis are convinced that peak demand is further out than green campaigners, a growing number of governments, and even some oil majors forecast. The Saudi view got a boost over the past year and a half. After energy demand plunged in 2020 during the pandemic, some forecasters thought oil consumption was fading fast. Yet the opposite appears to be true: Demand is rising fast, and the IEA says it will reach an all-time high by late 2022.
Even so, Abdulaziz knows from personal experience that some things are out of his control. Less than a week after he became oil minister, a drone attack on the oil processing center at Abqaiq in eastern Saudi Arabia shut down half of the country’s crude supplies for a few days. (The Saudi and U.S. governments blamed the attack on Iran, the kingdom’s great regional rival. Tehran denied any involvement.) Then, within months, came the price war with Russia and, this year, the collapse in OPEC+ talks.
Under pressure from shareholders to comply with climate change targets, international oil companies such as Exxon Mobil Corp. and Royal Dutch Shell Plc are being forced to cut spending on new exploration projects. The Saudis, who are able to benefit from some of the lowest production costs in the industry, believe there’s an opening for them: Invest now, when everyone else isn’t, and capture market share.
“If you are less predictable, you become more in command.”
“Ironically, funnily enough, the more people refrain from investing elsewhere, the more our possibility improves to increase our production,” Abdulaziz said via video link during

the June event organized by Bank of America, according to a person familiar with what was said.

Saudi Arabia's future as an oil superpower is all about control. What Abdulaziz did to Russia in the 2020 price war was a demonstration of that. It worked, if only temporarily: The Russians came relatively tamely back to the OPEC+ table even though the terms—on production, on price—weren't what they wanted. But Abdulaziz's 2020 power play did little to prevent the producer dispute in July.

One of Abdulaziz's strategies to cement Saudi control, as he's expressed it in private meetings with analysts and investors, is to mold OPEC into a kind of central bank, regulating the oil supply in much the same way the Federal Reserve regulates the money supply. Of his thinking, he told the JPMorgan clients, "I have copied and pasted what central bankers have done." In this scenario, Abdulaziz isn't just a regulator of one commodity's supply; he's an oil industry sheriff slapping down speculators messing with his territory. "I want the guys in the trading floors to be as jumpy as possible," he said at an OPEC+ news conference in September 2020. "I'm going to make sure whoever gambles on this market will be ouching like hell."

He put it even more colorfully the month before at a closed-door event organized by the Oxford Institute for Energy Studies. "I don't like the market or the speculators or the media to take us for granted; that's why I keep so many rabbits under my taqiyah," he said, referring to the traditional skullcap worn by Saudi men. "If you are less predictable, you become more in command."

Over the past year, Abdulaziz has had considerable success in his role. The price of U.S. oil has risen above $75 a barrel for the first time in more than six years, and OPEC+ has been able to boost production. Oil-consuming nations are once again begging the cartel to open the taps.

And yet Abdulaziz's complacent claims of dominance may come back to haunt him. His turbulent two years as energy minister—from the drone attack on Abqaiq through the 2020 price war to the devastating OPEC+ breakdown in July—demonstrate that, for all the oil it's sitting on, Saudi Arabia can't always count on the commodity it most strives for: total control.

Blas covers energy for Bloomberg News in London.

To contact the author of this story:
Javier Blas in London at jblas3@bloomberg.net
To contact the editor responsible for this story:
Stryker McGuire at smcguire12@bloomberg.net
Christine Harper

To view this story in Bloomberg click here:
https://blinks.bloomberg.com/news/stories/QWMOGCT1UM0X

Libya to Export 1.13M B/D of Crude, Condensate in July: Program
2021-07-22 15:42:26.883 GMT

By Sherry Su and Prejula Prem
(Bloomberg) -- Libya plans to export 34.89m bbl or 1.13m b/d of crude and condensate in July, according to loading program seen by Bloomberg.
* Compares with 1.1m b/d in June
* Sharara exports will be 5.88m bbl or 190k b/d in July, vs 174k b/d in June
** Volume revised higher from previously planned 178k b/d
* Es Sider loadings revised higher to 8.8m bbl or 284k b/d, vs 293k b/d in June
* Sarir/Mesla exports from Hariga terminal also revised higher to 7.63m bbl or 246k b/d, vs 187k b/d in June
* Zueitina loadings will be one cargo of 600k bbl in July, vs 1.2m bbl in June
* Loadings of other grades unchanged from the program released on July 1

To contact the reporters on this story:
Sherry Su in London at lsu23@bloomberg.net;
Prejula Prem in London at pprem1@bloomberg.net
To contact the editors responsible for this story:
Alaric Nightingale at anightingal1@bloomberg.net
Fred Pals

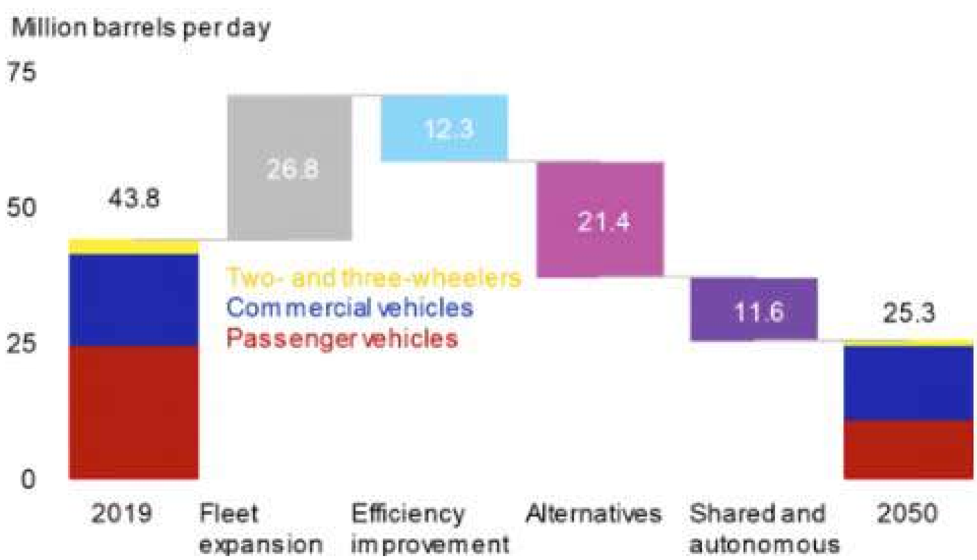
To view this story in Bloomberg click here:
https://blinks.bloomberg.com/news/stories/QWNJCQDWLU6E

BNEF Theme: The Outlook for Road Fuels
2021-07-21 09:20:37.428 GMT

By David Doherty
(BloombergNEF) -- Road transport accounts for more than 40% of global oil demand and more than half of total demand growth since 2000. In the past 100 years, a burgeoning population and rising prosperity have led demand for mobility to flourish. Oil-derived road fuel has powered this growth and shaped the way people and goods move. The next 30 years will bring significant changes as alternative drivetrains, shared mobility and eventually autonomous vehicles reshape road transport's reliance on oil.

BNEF View

Three forces threaten to impact the demand outlook for road fuels. The progression of mandated fuel-economy improvements for passenger cars and the introduction of fuel economy standards for commercial vehicles in key markets will reduce the intensity of oil demand per vehicle on the road. Growth in alternative drive trains such as electric and fuel-cell vehicles will displace oil-consuming internal combustion engine vehicles, and the proliferation of shared mobility services will impact vehicle ownership trends and lead to lower growth in demand for road fuels in some markets.



Change in road fuel demand, 2019-2050

This changing demand profile will erode profit margins and investment economics for the fuels marketing and refining sector. An increase in demand for diesel in heavy-duty applications is likely to contrast with declining demand for gasoline in light-duty transport. As new demand centers emerge, and consumption in more developed markets falls, refiners and fuel marketers will need to redefine their strategic approach in this fast-changing landscape.

To contact the reporter on this story:
David Doherty at ddoherty26@bloomberg.net
To contact the editor responsible for this story:
Bryony Collins at bcollins32@bloomberg.net

To view this story in Bloomberg click here:
https://blinks.bloomberg.com/news/stories/QWL8MDT0G1KZ

China Offers Oil Reserves in Unprecedented Move to Cool Rally
2021-07-22 05:51:56.67 GMT

By Alfred Cang
(Bloomberg) -- China offered millions of barrels of oil from its strategic state reserves this month in an unprecedented move to try and quell inflation brought on by rising costs of everything from food to fuel.
The country will supply about 3 million tons -- or 22 million barrels -- to major refineries, according to people with knowledge of the matter, who asked not to be identified as the information is sensitive. The decision is the latest in a slew of measures by the world's second-largest economy to rein in skyrocketing costs caused by a post-pandemic economic recovery.
Read Also: China's Campaign to Control Commodities Goes Into Overdrive
Global benchmark Brent crude topped $75 a barrel in the weeks running up to the move, a level last seen in 2018, as a public spat between OPEC+ members delayed a crucial decision to raise output. While the alliance ultimately agreed on a deal to boost supply to a market tightening from rebounding demand, oil prices remain almost 40% higher than at the start of the year.
The release of reserves could weigh on China's consumption of imported crude, even though details on timing remains unclear. The nation's overall demand for foreign oil hinges on major refiners, after private processors took a hit from increased government scrutiny that included the rollout of tariffs, which eroded profitability.
The plan was first reported by Energy Intelligence. No one answered calls to the press office of China's National Food and Strategic Reserves Administration, which oversees the oil reserves. There was also no response to a fax sent to the National Development and Reform Commission. The National Energy Administration was formerly responsible for the reserves.

Mixed Reaction

Since early-2021, Beijing has ramped up efforts to control surging prices that have seeped into everything from the cost of power to daily meals. Raw material costs are up on a strong economic recovery from China to the U.S. to Europe, as well as virus-related labor and supply-chain woes. Beijing has gone after speculators and released state metals and coal stockpiles in a bid to prevent rallying prices from denting its own growth.
Read Also: China Starts a War on Commodity Prices Goldman Says It Can't Win
These sales, however, have garnered mixed responses from the market. Since announcing the sale of stockpiled base metals including copper, aluminum and zinc on June 16, domestic futures prices have been little changed, or risen slightly. For grains, prices are down about 1.5% after China offered stockpiled corn on July 9.

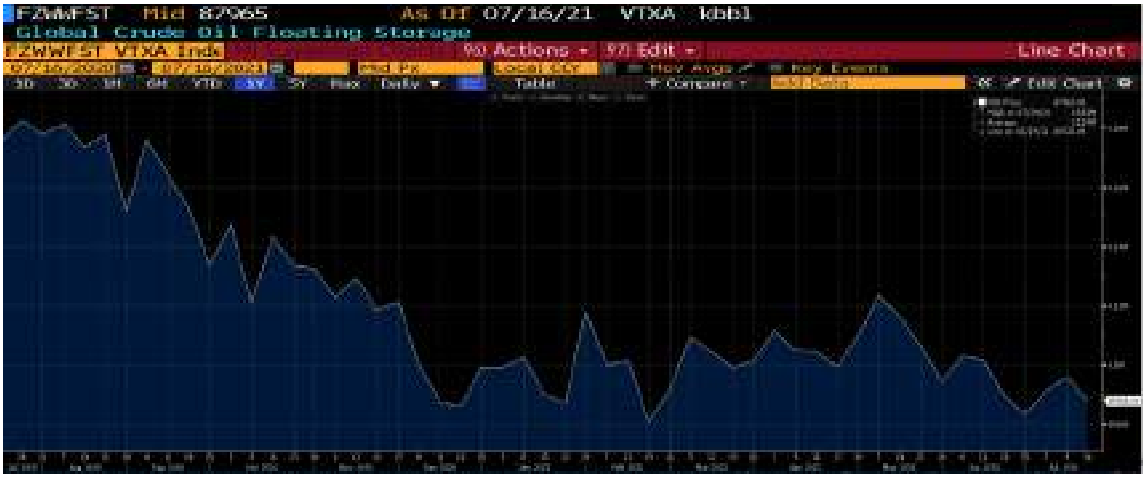
The department in charge of non-oil commodity stockpiles said Wednesday that it will increase the amount of base metals it will sell by as much as 80%, compared with its previous auction, indicating it hasn't given up its effort to stop the rally. Goldman Sachs Group Inc. and Citigroup Inc. say China's actions to control prices will likely fail.

Oil Refiners

Brent has lost more than 2% since the start of the week, when speculation of the reserves release began, after capping a 2.6% weekly decline Friday. The sale of Chinese state oil reserves adds to other concerns stemming from the spread of the delta virus variant and a stronger U.S. dollar.
As for the major Chinese refiners that were offered barrels, Beijing's move will help these processors avoid running short of crude amid a drawdown of their own stockpiles, which has occurred since the fourth quarter of 2020, wrote Energy Aspects Ltd. analysts Yuntao Liu and Amrita Sen in a note dated July 21.
Additionally, access to oil from state reserves will also support a ramp-up in refinery run rates as plants return from maintenance work, they added. Energy Aspects expects Chinese crude processing rates to increase by 430,000 barrels a day during the third quarter from the previous three months, up from an earlier forecast of 210,000 barrels a day.

--With assistance from Sarah Chen and Alaric Nightingale.

To contact the reporter on this story:
Alfred Cang in Singapore at acang@bloomberg.net
To contact the editors responsible for this story:
Anna Kitanaka at akitanaka@bloomberg.net
Serene Cheong, Ben Sharples



Crude Oil in Floating Storage Falls 8.3% in Past Week: Vortexa
2021-07-19 07:00:01.454 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 fell to 87.97m bbl as of July 16, Vortexa data show.
* That's down 8.3% from 95.88m bbl on July 9
* Asia Pacific down 13% w/w to 52.42m bbl
* Middle East up 12% w/w to 10.18m bbl
* West Africa down 7.7% w/w to 7.92m bbl
* Europe down 6.7% w/w to 5.89m bbl
* North Sea down 30% w/w to 2.54m bbl
* U.S. Gulf Coast up 72% w/w to 1.45m 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:
+1-212-617-2000 or newsauto@bloomberg.net

To view this story in Bloomberg click here:
https://blinks.bloomberg.com/news/stories/QWHCS1GQITJ4

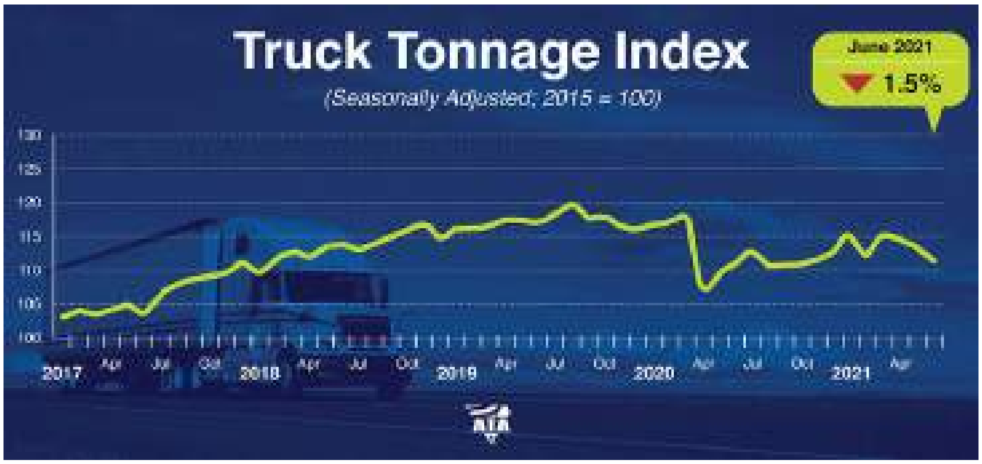
https://www.trucking.org/news-insights/ata-truck-tonnage-index-decreased-15-june

ATA TRUCK TONNAGE INDEX DECREASED 1.5% IN JUNE

Jul 20 Media Contact:Jeremy Kirkpatrick

Index 0.5% Above June 2020

Arlington, Virginia — American Trucking Associations' advanced seasonally adjusted (SA) For-Hire Truck Tonnage Index decreased 1.5% in June after falling 1% in May. In June, the index equaled 111.6 (2015=100) compared with 113.3 in May.



"Tonnage has definitely flattened out, on average, over the last six to nine months," said **ATA Chief Economist Bob Costello**. "The good news is that it remains slightly above 2020 levels.

"Supply chain issues are likely putting some downward pressure on tonnage," he said. "But it is also likely that tonnage isn't growing as much as it could because of industry-specific supply constraints. This index is dominated by contract freight, and the for-hire truckload carriers have seen their tractor counts fall because they are having difficulty finding qualified drivers. It is difficult to move more tonnage with less equipment, which is why we are seeing strong volumes in the spot market as shippers scramble to get loads moved."

May's reading was revised down slightly to -1% from our June 22 press release.

Compared with June 2020, the SA index rose 0.5%, which was preceded by a 3.3% year-over-year increase in May. Year-to-date, compared with the same six months in 2020, tonnage is up 0.3%.

The not seasonally adjusted index, which represents the change in tonnage actually hauled by the fleets before any seasonal adjustment, equaled 116.2 in June, 2.4% above the May level (113.4). In calculating the index, 100 represents 2015. ATA's For-Hire Truck Tonnage Index is dominated by contract freight as opposed to spot market freight.

Trucking serves as a barometer of the U.S. economy, representing 72.5% of tonnage carried by all modes of domestic freight transportation, including manufactured and retail goods. Trucks hauled 11.84 billion tons of freight in 2019. Motor carriers collected $791.7 billion, or 80.4% of total revenue earned by all transport modes.

ATA calculates the tonnage index based on surveys from its membership and has been doing so since the 1970s. This is a preliminary figure and subject to change in the final report issued around the 5th day of each month. The report includes month-to-month and year-over-year results, relevant economic comparisons, and key financial indicators.

With that, I will turn the call over to Lorenzo.

Lorenzo Simonelli {BIO 15243700 <GO>}

Thank you, Jud. Good morning, everyone, and thanks for joining us. During the second quarter, we generated strong free cash flow with several key awards and took a number of positive steps in our journey to grow our new energy businesses. At a product company level, TPS once again delivered solid orders and operating income, while OFE booked a solid awards for quarter and OFS continued to improve margins.

As we look to the second half of 2021 and into 2022, we see continued signs of global economic recovery that should drive further demand growth for oil and natural gas. Although, we recognize the risk presented by the various strains of the COVID-19 virus, we believe that the oil price environment looks constructive with demand recovering and operators largely maintaining spending discipline. In the natural gas and LNG markets, fundamentals are equally as strong, if not better than oil.

As a combination of outages and strong demand in Asia, Latin America and Europe, have driven third quarter LNG prices to levels not seen since 2015. Although hot weather in Europe and US has contributed solid demand improvement and lower gas storage levels, structural growth continues unabated in Asia, with Chinese LNG imports up almost 30% in the first half of 2021 versus the first half of 2020.

Given the strong pace of current growth and the increasing demand for cleaner sources of energy, we maintain our positive long-term outlook for natural gas and LNG. Outside of traditional oil and gas, the momentum for cleaner energy project continues to increase around the world.

In the U.S., Europe and Asia, various projects around wind, solar and green and blue hydrogen are moving forward, as well as a number of carbon capture projects. For example, so far this year, there have been 21 CCUS projects announced, and in the early stages of development compared to 19 CCUS projects announced in 2020.

During the second quarter, we continued to build on a key pillar of our strategy to position for some of these new energy frontiers. Our team has moved quickly and decisively and selected areas to establish relationships and build a strong foundation for the future commercial success. Our approach has been one of collaboration and flexibility, which is reflected in the number of agreements we reached in the second quarter, ranging from early stage partnerships and MOUs to more immediate investments, commercial agreement and tangible orders for Baker Hughes.

Most recently, we announced the collaboration with Samsung Engineering for low to zero carbon projects, utilizing hydrogen and CCUS technologies. As part of the collaboration, we'll work with Samsung Engineering to identify joint business development opportunities for Korean energy and industrial customers domestically and abroad can help reduce their emissions.

Baker Hughes will look to deploy compression and NovaLT gas turbine technology as well as flexible pipes for transportation in hydrogen. In CCUS, we will be providing reservoir studies, well construction services, flexible pipes, condition monitoring solutions and safety[ph] solution such as carbon dioxide compression and liquefaction of the key industrial assets.

Another example of our early stage partnerships is the collaboration agreement we reached with Bloom Energy on the potential commercialization and deployment of integrated, low-carbon power generation and hydrogen solutions. This partnership will allow Baker Hughes to work with Bloom Energy across a number of areas, including integrated power solutions, integrated hydrogen solutions, and other technical collaborations. Bloom Energy is a leading clean energy player with solid oxide fuel cell technology in natural gas and hydrogen and a growing electrolyzer presence. Through this agreement, we will gain forever insights into fuel cell and electrolyzer technologies where Bloom has key offerings to date and explore how we can integrate and utilize our world-class gas cabinet compression technology alongside this solutions.

We're also very pleased to announce an MOU with Borg CO2, a Norwegian carbon capture and storage developer to collaborate on our CCUS project to serve as a hub for the decarbonization of industrial sites in the Viken region of Norway. Both industrial cluster approach provides a great opportunity to Baker Hughes to test and scale our wide-ranging CCUS portfolio, including our chilled ammonia process and our compact carbon capture solution. This builds on our MOU with Horisont Energi for the Polaris carbon storage project in Norway announced last quarter.

During the quarter, we also announced the 15% investments in Electrochaea to expand Baker Hughes CCUS portfolio with power to gas and energy storage solutions. Baker Hughes will combine its post-combustion carbon capture technology with Electrochaea's bio-methanation technology to transform CO2 emissions into synthetic natural gas, a low carbon fuel capable of being used across multiple industries.

Lastly, during the second quarter, we were extremely pleased to finalize our collaboration with Air Products, a global leader in hydrogen to develop next-generation hydrogen compression and accelerate the adoption of hydrogen as a zero carbon fuel. As part of the collaboration, Baker Hughes will provide Air Products with advanced hydrogen compression and gas turbine technology for global projects. This includes NovaLT16 gas turbines and compression equipments, but there are net zero hydrogen energy complex in Alberta Canada. We will also provide advanced compression technology using our high pressure ratio compressors at the neon carbon free hydrogen project in Saudi Arabia. Through these two projects with Air products, Baker Hughes will provide equipment on the world's largest blue and green hydrogen projects.

As you can see from all these recent announcements, we feel confident in the momentum we're building in both CCUS and hydrogen spaces. And believe that we have a differentiated technology offering that positions us as a leader in these areas.

Now, I'll give you an update on each of our segments. In Oilfield Services, increases in activity level became more broad-based during the second quarter. And the outlook for the second half of the year continues to improve. Internationally, we have seen a pickup in activity across multiple regions over the last few months, including Latin America, Southeast Asia, and the North Sea. Looking at the second half of the year, we expect stronger growth across a broader range of markets, most notably in the Middle East and Russia. Based on discussions with our customers, we expect international activity to gain momentum over the second half of the year and lay the foundation for growth in 2022.

In North America, strong second quarter growth was evenly distributed between our onshore and offshore business lines. Given the strength in oil prices and bid activity, we expect to see additional growth over the second half of the year. While we expect to capitalize on the growing improvement in global activity levels, we are committed to being disciplined through this upcycle, with a focus on profitability and returns. This includes maintained focus on our various cost reduction and operating efficiency initiatives as well as navigating the inflation and supply chain costs, a situation that our team is managing well. As a result, OFS remains on track to achieve our goal of 20% EBITDA margins in the medium term.

Moving to TPS, the outlet continues to improve, driven by opportunities in LNG, onshore offshore production, pumps, and valves and new energy initiatives. While the older outlook for TPS in 2021 should be roughly consistent with 2020, we are proving increasingly confident that our multi-year growth opportunity will begin to emerge in 2022. Underpinning this framework is the strength that is developing in multiple parts of the TPS portfolio and the diversification of the business, which has commercial offerings in several end-markets with high growth opportunities.

In LNG, we booked two awards during the second quarter with gas turbines and compressors to Train 7 at Nigeria LNG. And liquefaction equipment for new Fortress's Energy's first Fast LNG project. Following these two orders, we still expect one or two more LNG awards in 2021, and see a strong pipeline of opportunities that should produce a step up in LNG activity in 2022 and beyond.

For the non-LNG segments of our TPS portfolio, we were pleased to book awards in the Middle East and Asia Pacific in our refinery and pipeline and gas processing segments. TPS also secured a key industrial win with our NovaLT12 megawatt gas turbine technology in the Middle East for a combined heat and power application. We continue to see our NovaLT range of gas turbines gain server traction below a megawatt industrial applications.

The TPS services, we are beginning to see real signs of recovery and remain optimistic about the outlook for 2021 and 2022. In the second quarter, we experienced strong growth in service orders, which grew year-over-year due to the significant upgrade awards across multiple regions and for the various applications including pipeline, offshore, and solutions to support customers operational decarbonization efforts.

We also saw favorable improvements in transactional service orders as customers continued to increase spending. In our contractual services business, TPS maintains strategic long-term relationships with LNG customers, achieving a major milestone by securing a six-year services contract extension in North America for a key producer, building on the success we saw in the first quarter. Our TPS services RPO now stands at close to $14.1 billion, which is up almost 10% year-over-year.

Next on Oilfield Equipment. We remain focused on right-sizing the business, improving profitability and optimizing the portfolio in the phase of what remains a challenged long-term offshore outlook. While Brent prices are near $70, NFID activity is beginning to pick up, we continue to expect only a modest improvement in industry subsea tree awards in 2021, followed by some additional growth in 2022.

However, we continue to believe that it will be difficult to achieve and sustain 2019 order levels in the coming years, as the deepwater market becomes increasingly concentrated into low-cost basement and upstream spending budgets for many larger operators are reallocated to other areas. However, one deepwater area that we expect to benefit from this environment is Brazil with a pre-salt reserves are viewed as attractive by a number of IOCs.

This quarter, our flexible business signed an important frame agreement with Petrobras for a number of free and postal fields offshore Brazil. In the past half of 2021 and including the two contracts we were awarded in the first quarter, Petrobras has contracted Baker Hughes to provide up to 370 kilometers of flexible pipe. This is larger than the volume of flexible pipe awarded by Petrobras to Baker Hughes in 2019 and 2020 combined.

Finally, in digital solutions, we were pleased to see orders continue to recover, despite the challenging operating quarter. Year-over-year growth in orders was led by strong performances in our industrial and transportation end markets. We saw continued traction in industrial end markets in the second quarter which represented over 30% of DS second quarter orders, as we continue to grow our presence in this key area.

During the quarter, DS continued to expand its industrial asset management presence with a number of wins across multiple end markets. Bently Nevada secured a contract with a large corrugated paper manufacturing company for its condition monitoring and protection solutions to optimize production and reduce maintenance costs.

We were also pleased to see the recently acquired ARMS Reliability business, secured some industrial asset management orders during the quarter, including a subscription for its OnePM software to be deployed by a global chemicals customer with initial rollout in China and Chile. The deal will include software and consulting services to develop the customers equipment liability strategy library, driving the deployment of best-in-class asset reliability strategies and real-time alignment for its assets.

We're also having success integrating some of our emissions management solutions with our Bently Nevada business. This quarter, we have secured a flare.IQ contract with bp, marking the first time flare.IQ will be used in upstream oil and gas. This contract builds on

50%, given the capital efficiency of our portfolio and the winding down of the restructuring and separation cost.

Now, I will walk you through the segment results in more detail and give you our thoughts on the outlook going forward. In Oilfield Services, the team delivered a good quarter in an improving market environment. OFS revenue in the quarter was $2.4 billion, up 7% sequentially. International revenue was up 6% sequentially, led by increases in Asia Pacific, Europe and Latin America.

North American revenue increased 11% with solid growth in both our U.S. land and offshore businesses. Operating income was $171 million, up 20% sequentially and margin rate expanded 80 basis points to 7.3% due to higher volume and lower depreciation. While we continue to execute on our cost out program in the second quarter, this was partially offset by mix and cost inflation in some areas. Although, we have moved quickly to pass inflation on to our customers, there is a timing lag relative to the increasing costs. As we look ahead to the third quarter, we expect to see strong sequential improvement in international activity and continued improvement in North America.

As a result, we expect sequential revenue growth for OFS in the third quarter to be similar to the second quarter. On the margin side, we expect the sequential increase in operating margin rate to solidly exceed the improvement in the second quarter due to more favorable mix and better cost recovery.

For the full-year 2021, our industry outlook remains largely intact with second half activity in North America modestly better than previously expected. Overall, we still expect our OFS revenue to be down slightly year-over-year with North American revenues roughly flat and international revenue down mid-single digits. On the margin side, we continue to expect growth in operating income and margin rates on a year-over-year basis.

Leading to Oilfield Equipment, orders in the quarter were $681 million, down 3% year-over-year and up 97% sequentially. Strong year-over-year growth in subsea services and flexibles orders was offset by declines in SPC projects, and subsea production systems. The sequential improvement in the orders was driven by an increase in orders in SPS along with several orders in flexibles outside of Brazil. Revenue was $637 million, down 8% year-over-year, primarily driven by declines in subsea drilling systems and the disposition of SPC flow, partially offset by growth in flexibles.

Operating income was $28 million, which is up $42 million year-over-year. This was driven by increased volumes in flexibles as well as productivity for my cost out programs. For the third quarter, we expect revenue to decrease sequentially, driven by lower SPS and flexibles backlog conversion. We expect operating margin rate in the low-single digits.

For the full year 2021, we believe the offshore markets will remain challenged as operators reassess their portfolios in project selection. We expect OFE revenue to be down double digits on a year-over-year basis, due to the lower order intake in 2020 and a likely continuation of a lower order environment in 2021. Although revenue is likely to be down

Overall, we delivered a solid quarter and continued strong free cash flow. While we faced challenges in our DS business, we are confident in our ability to execute as the rest of the year unfolds.

With that, I will turn the call back over to Jud.

Jud Bailey {BIO 6198676 <GO>}

Thanks, Brian. Operator, let's open the call for questions.

Questions And Answers

Operator

(Question And Answer)

Thank you. (Operator Instructions) Our first question comes from Chase Mulvehill with Bank of America.

Q - Chase Mulvehill {BIO 17240736 <GO>}

Hey, good morning. Lorenzo, early in your prepared remarks you talked about a looming new order growth cycle in the TPS segment that you get underway next year. Could you maybe just take a minute and provide some details around kind of really what's driving this revised more positive outlook for TPS as we get into next year?

A - Lorenzo Simonelli {BIO 15243700 <GO>}

Yeah. Definitely, Chase. As you mentioned, for TPS we see several avenues of growth developing as we go forward, and really it's for a prolonged growth cycle of orders and EBITDA. As you look at the net intermediate term, it's really going to be LNG and the orders that we're seeing. You can also see the small awards we've booked this year, we still see some other maybe one or two small projects being awarded this year. But as we go forward the next two to three years, we see a step up in LNG order opportunity, as been highlighted by the increasing demand. And also what we announced previously, the long-term outlook of LNG out to 2030.

Then as you go longer term, also the next 5 to 10 years we expect to see significant growth around our energy transition initiatives, most notably hydrogen CCUS. But also in areas like valves, integrated power as the clean energy ecosystem continues to evolve. And I think if you look at our recent announcements with our product, that was given, we see some near-term opportunities for hydrogen and those will actually be additional awards over the course of the next two to three years as the first wave, but continuing through the rest of the decade. And CCUS, you looked at our announcement with Borg and Horizon Energy, and we're in a number of active collaborations with our customers across several geographies of increasing opportunities around CCUS.

Yeah, James, I think it's -- part of our strategy, as we've said, to develop a portfolio for energy transition. And we're very pleased with the Electrochaea investment, 15% investment which really allows us to expand our whole portfolio around power to gas and energy storage solutions. We'll have a seat on the board of Electrochaea and we're really going to combine our post-combustion carbon capture technology with Electrochaea's bio-methanation technology to transform CO2 emissions into synthetic natural gas.

And this may be an area that we haven't discussed much before, but we really see synthetic natural gas as being applicable to multiple industries and Electrochaea's technology allows CO2 recycling into grid quality, low-carbon synthetic natural gas, which helps to drive decarbonization and help both sectors, such as transportation and heating. So, it's going to be a great suite of a capability that we're providing. And again, we see this being applicable to power, industrial plants, and again, it's increasing our portfolio of applications.

Q - Chase Mulvehill {BIO 17240736 <GO>}

Got it. Thanks, Lorenzo. Thanks, Brian.

Operator

Thank you. Our next question comes from Scott Gruber with Citigroup.

Q - Scott Gruber {BIO 6761975 <GO>}

Yes, good morning.

A - Lorenzo Simonelli {BIO 15243700 <GO>}

Hey, Scott.

Q - Scott Gruber {BIO 6761975 <GO>}

Morning. Brian, one for you on inflation, you mentioned that you're pushing through price increases to offset inflation, but couple of questions. One, are customers generally willing to accept the price increases across the portfolio? Are there some puts and takes we should be thinking about? And B, based upon the time lag, when will the price increases catch up with inflation that we've seen thus far?

A - Brian Worrell {BIO 16231736 <GO>}

Yeah. Scott, look, I'd love to tell you that customers -- all customers say, yeah, sure, go ahead and pass on price increases. But look, they clearly understand what's going on in the commodity markets. We have some contractual arrangements that allow us to pass those along and we're having discussions in places where it's not so clear. And look, we have seen some traction there and started to see some pricing power come back across the portfolio, not everywhere, but we're certainly seeing that capability. We did get some price in the second quarter, but as I've mentioned, it takes a little while longer for some of that to kick in versus the inputs that are coming.

So look, I'd say, over the course of this year we'll continue to push that and try to make sure that the price increases are offsetting as much of the inflation as possible. The one thing I would point out too is that, we've got a global supply chain, we've got pretty good contractual arrangements in place. And have been working with our suppliers as we started to see this coming through to mute some of the impact this year. Obviously, we have some hedges in place as well. And look, really focused on looking at 2022 and making sure we're securing things for next year as well. So I'd say, it's great collaboration with the sourcing and the commercial teams in working through this. But feel good about the actions that we've taken.

Q - Scott Gruber {BIO 6761975 <GO>}

Got it. And based upon your efforts there and your activity outlook, how are you thinking about the timing of when you could get that to the 20% EBITDA margin in OFS?

A - Brian Worrell {BIO 16231736 <GO>}

Yeah, look, I -- listen Maria Claudia and the team are continuing to do a great job in executing on all the restructuring and cost out and transformation initiatives that the team has been driving there. And you've seen that come through in the results here in the first half with the margin rate improvements that the team has posted. They're working hard to offset some of this inflation like we talked about here. And I'd say, with the backdrop we see in volume for the second half of this year into 2022, I could certainly see us hitting that 20% rate sometime next year in any given quarter and be really well set up as we execute in 2022 and exit the year. But I think that the team is doing a really good job of managing cost and driving productivity. And I think we're still on a really good trajectory here.

Q - Scott Gruber {BIO 6761975 <GO>}

Got it. Appreciate the color, Brian. Thank you.

A - Brian Worrell {BIO 16231736 <GO>}

All right. Great. Thanks, Scott.

Operator

Our next question comes from David Anderson with Barclays.

Q - David Anderson {BIO 6875231 <GO>}

Hey. Good morning. Just want to follow-up on last guy's question there, on that 20% margin. So, maybe not timing but maybe how do you get there? I mean, is it pricing? You talked about operating leverage, or is there a component of mix here is required to get to the 20%? You talked about a couple of integrated drilling and well services contracts, which I assume are more creative than traditional services. So is that another component here? Maybe just kind of talk about that mix, what that has to -- what do we have to see to get to that 20%?

A - Brian Worrell {BIO 16231736 <GO>}

Yeah. David, look, we're not counting on a significant mix shift to be able to deliver that level of margin. Sure, if some of the product lines that have higher margin rates get more tailwinds, that will certainly help. But we've taken the approach of driving improvement across the entire business. We've done a lot around remote operations, we've multi-skilled the work force to be able to deploy them in different ways and more effectively. We've made massive changes inside the supply chain and in our service shops, and you've seen us take a lot of costs out with the restructuring. And so a lot of those process improvements and cost out are going to continue. And that's really what's going to drive the margin rate. So the actions have already been launched and the team is certainly executing on those.

Now, the pricing that we're talking about here is really to offset some of the inflation that we're seeing, so we're not counting on any pricing increases to drive that margin improvement. But if we can get those pricing increases to stick, and hold inflation levels down, I think that could provide some upside. So it's been a fundamental change in how that business is operating, how Maria and Claudia and the team are leading it and how we're allocating capital, and that's really what's driving the improvement here and we're making it fundamental and long-lasting.

Q - David Anderson {BIO 6875231 <GO>}

Great, thanks for the insight there, Brian. A different question, Lorenzo, sort of a bigger picture. We're starting to get more generous investors back into the space here, people starting to look and people starting to buy into it, the cycle starting to pick up. Now, Baker Hughes has a very different business portfolio than your peers. So I was just wondering maybe you could just kind of talk about kind of over the next two to three years, maybe helping people understand what parts of your business do you think are going to have more pronounced growth and margin expansion? Really I guess what I'm asking, what parts do you guys expect to outperform over the next two, three years as the cycle accelerates? I guess, I'm just sort of thinking about your four segments and how you sort of see them kind of progressing here.

A - Lorenzo Simonelli {BIO 15243700 <GO>}

Yeah, David. If you look at it from a macro picture and again you look to the response given on the TPS cycle, that's really taking place here with the opportunity of LNG in the next few years, also the energy transition opportunities. And in our last call we mentioned the addressable markets of hydrogen by 2030 being $25 billion to $30 billion and CCUS being $35 billion to $40 billion for Baker Hughes. So, clearly as you look at the macro picture, the long-term growth prospects of our TPS business look very solid. Also in the short term, with the continued rebound in some of the upstream and also the production site, Oilfield Services continuing to perform well. So short term you'll see that pickup, and longer-term the TPS business continues to have a good future.

Q - David Anderson {BIO 6875231 <GO>}

Great. Thank you very much.

Operator

Yeah. Ian, I think our focus is on creating shareholder value and what's best for shareholders longer time. So, we're running the company today really to execute on the three pillars of our strategy, transform the core, invest for growth and also new frontiers. And we're going to be looking at margin accretion and continuing to allocate capital accordingly. I think as we look forward, it's going to require from an energy transition perspective scale, build an extensive customer reach and sizable R&D. So, technology spending going into that. We think our current footprint provides for that. I think when you look at overall, it's becoming apparent that the new growth -- energy growth opportunities in TPS are significant, where when you look at the OFE business, it's a more of a mature business.

Q - Ian Macpherson {BIO 15106867 <GO>}

Certainly. Well, I'll stay tuned with that. Thank you both for all the inside today.

Operator

Thank you. Our next question comes from Marc Bianchi with Cowen.

Q - Marc Bianchi {BIO 18339369 <GO>}

Thank you. I first wanted to ask about OFS, the outlook in '22. There's one of your peers reported the other day and said that they expect mid-teens compound annual growth over '22 and '23. I'm just curious, how you're looking at that outlook and what you think specifically in '22?

A - Lorenzo Simonelli {BIO 15243700 <GO>}

Yeah, just maybe let's start off with the international outlook. And again, we do see a solid step up in growth internationally over the second half of the year. So far this year we've seen strong recovery in Latin America and North -- Southeast Asia. The Middle East has somewhat lagged, but we expect incremental stronger activity over the course of the second half and into 2022, as well as in Russia being bigger contributors to the second half as well. So we've been somewhat more conservative in forecasting international activities, I think you know that. It really depends on how some of the regions come back.

Right now, we think growth in the second half of the year could be in the high-single digits or low-double digits on a year-over-year basis. And we expect that momentum to continue into 2022 with solid growth opportunities. North America, we generally expect the rig count to continue to trend a little higher over the second half, maybe adding an additional 50 rigs or so by the end of the year. So that would imply a modest improvement in the third quarter and fourth quarter. When you look at 2022, again, we anticipate solid growth with the prices holding at the range they are now. But similar to this year, we expect some of the privates to be active and at these prices that some of the public E&Ps also will continue to be only increasing their spending modestly as they continue to adjust some of their operating cash flow to some of the other areas of capital spending.

Q - Marc Bianchi {BIO 18339369 <GO>}

Got it. Thanks for that, Lorenzo. And shifting over to, you have these two awards with their products and they've got very large projects that they're pursuing. But they don't come on stream until I guess NEOM is '25 and this thing in Canada, the Blue Hydrogen is '24. Do those projects need to be up and running for the floodgates to kind of open on these types of awards or could we see more familiar products for Baker Huges over the near term?

A - Lorenzo Simonelli {BIO 15243700 <GO>}

No, I think it's fair to say that we're seeing a number of discussions with customers and partners continuing to gain momentum. It's great to have achieved the announcement with their products. And again, when you look at those orders converting, we expected to be in the near term. And I think that, again, as these projects start to get on the go, you'll see others also follow as well. So, we're focused on enabling the technology and with their product we're going to be on the largest blue and green hydrogen projects that are out there at the moment, providing our best technology.

A - Brian Worrell {BIO 16231736 <GO>}

Yes. Mark, and I would just add actually, in terms of bid activity and inquiries with customers over the last six months, they're up 2x what we were seeing in the fourth quarter of last year. So, activity levels have definitely increased, I expect to continue to see that to increase. And look, exactly when they'll turn into orders, it's a bit tough to say right now, but there's a lot going on.

Q - Marc Bianchi {BIO 18339369 <GO>}

Got it. Thanks very much, guys.

A - Lorenzo Simonelli {BIO 15243700 <GO>}

Thanks, Mark.

Operator

Our next question comes from Arun Jayaram with JPMorgan.

Q - Arun Jayaram {BIO 5817622 <GO>}

Yeah. Good morning, Lorenzo. A number of announcements on the ET front during the quarter. I was wondering if you could maybe talk about some of the competitive dynamics in CCUS, your views on Baker's position. And maybe just as a follow-up, could you talk a little bit about the scope of the Borg project. And how do these initial projects and CCUS line up, could these be accretive to your margins assuming good execution?

A - Lorenzo Simonelli {BIO 15243700 <GO>}

Yeah. Firstly, I think, I feel very good about the positioning that we're developing around CCUS. And if you look at it from a value chain perspective, we really go across the board of CCUS from the initial identification of where CO2 can be sequestered, all the way to the transportation and also the compression capability. We've also developed multiple solutions for CCUS, you've seen in the past, we've got the chilled ammonia process, we've got the mixed salt, we've also got compact carbon capture. So, we're providing the different solutions because there's no one solution that's going to be for everybody. And like in LNG, we want to be able to provide capabilities for small, medium and large scale as they get undertaken.

Specifically on Borg, the Borg MOU announcement allows us again to really play at the forefront of capturing and storing up to 630,000 tons of CO2 emissions annually. And they're going to be utilizing our technology to do that, and we're also going to be able to see an industrial cluster approach. That's a great opportunity for us, because we think those industrial clusters are going to continue to emerge elsewhere in the world as well. So Norway is at the forefront there and we're at the forefront with both CO2 and also the Norwegian lights.

Q - Arun Jayaram {BIO 5817622 <GO>}

Great. And just my follow-up is just on digital. It sounds like just the margin missed this quarter's is driven by a one-time legacy contract, and -- so maybe you could outline, do you still feel good about trending towards perhaps low double-digit margins as we go through the year on digital?

A - Brian Worrell {BIO 16231736 <GO>}

Yeah, we do feel good about the buying recovery we're seeing in quite a few of the end markets, particularly on the industrial side of DS. And we were disappointed in the margin rate, which was really a function of project delays for this legacy software contract. And just to clarify, this legacy software contract goes back several years and isn't associated with our C3.ai partnership. And so this resulted in some higher cost and not revenue here in the quarter, and that was the biggest driver.

I will note there was a little bit of incremental cost we had in the R&D front in DS this quarter related to some strategic areas like the ARMS reliability acquisition that we did earlier in the year, and some acceleration of some work we were doing around emissions management. And I'd say, looking ahead and the third and fourth quarters, I don't expect overall level of cost in DS to be at the level that you saw here in the second quarter. So, we do think the business is going to be back on track to generate higher margins with the volume growth that we're seeing and cost levels back to lower levels to support those higher margin rate.

Q - Arun Jayaram {BIO 5817622 <GO>}

Great, thank you.

A - Lorenzo Simonelli {BIO 15243700 <GO>}

Thanks, Arun.

Operator

Additional details and reconciliation to the most directly comparable GAAP financial measures are included in our second quarter earnings release and can also be found in the Quarterly Results and section of our website. After our prepared remarks, we ask that you please limit yourself to one question and one related follow-up during the Q&A period in order to allow time for others who may be in the queue. Now I will turn the call over to Jeff.

Jeff Miller {BIO 17768856 <GO>}

Thank you. Abu and good morning everyone. Our performance in the second quarter demonstrates that our clear strategy is working well and Halliburton strategic priorities are driving value. Let's get right to the highlights. Total company revenue increased 7% sequentially as both North America and international top line continued to improve. Operating income grew 17% with solid margin performance in both divisions.

Our Completion and Production division, revenue increased 10% driven by the strength in US land completions. C&P delivered operating margin of 16% in the second quarter, reaching three year highs. Our Drilling and Evaluation division revenue grew 5% operating margin of 11% was about flat sequentially with rig count increases across multiple regions offsetting a seasonal decline in software sales.

North America revenue grew 12% as both drilling and completions activity marched higher throughout the quarter. Increased utilization and our significant operating leverage supported sequential margin expansion. International revenue grew 4% sequentially with activity increasing in the key producing regions of the world despite COVID-19 disruptions in various countries.

Finally we generated strong free cash flow this quarter, bringing the year-to-date free cash flow to almost $425 million. I'm pleased with the solid performance we delivered in the first half of this transition year while recent market volatility only demonstrates the fact that we remain in a transition year. Today I want to spend more time discussing what I believe will unfold over the next couple of years. First let me reaffirm the outlook for the rest of this year.

In the second half of 2021, we expect activity momentum to continue. Internationally, we still anticipate a double-digit increase in activity compared to the second half of 2020 even a certain countries continue to face COVID disruptions with commodity prices remaining supportive we believe activity in North America inches higher with drilling outpacing completions as operators build up well inventory for 2022.

Looking beyond this year. Let me describe the longer-term outlook we believe that we are in the early innings of a multiyear upcycle for the first time in seven years. We anticipate simultaneous growth in international and North America, markets and this view guides our business objectives, and expected outcomes so here's how we see the macro industry environment playing out over the next couple of years.

First we believe commodity prices will remain structurally supported with both demand resurgence in many economies and increased vaccine availability, we anticipate the global demand will continue to exceed supply, particularly to the extent OPEC plus manages supply additions over the near term. As OPEC plus spare capacity returns to normalized levels over the next year. We believe sufficient pent up global oil demand will support a call on both international and US production.

Second multiple years of under-investment in the international markets, coupled with the anticipated oil and gas demand growth give us confidence and a healthy international recovery I believe the growth will be led by the national oil companies and focused on shorter cycle barrels this activity should come with higher service intensity and higher relative capital spend around the wellbore as opposed to long cycle infrastructure investments we expect mature fields, both onshore and offshore to attract the most investment large scale greenfield exploration will be limited to a few markets in Africa and Latin America.

As a result, we anticipate double-digit annual international spending growth at least over the next couple of years. Third we believe that a supportive commodity price environment. Normalized levels of spare OPEC plus capacity and high decline rates in US shale are constructive for North American spending. We expect, drilling and completion spending in North America will also grow double-digits annually over the next two years. Although activity will not return to pre-pandemic levels.

We expect private operators to opportunistically lead the activity come back, while public E&Ps balanced growth and returns. Fourth, I believe equipment availability will tighten much faster than most people thing in multiple product lines. We believe that equipment supply will fall behind anticipated demand today both drilling and completions equipment are nearing tightness in North America. And we expect to see international markets tighten over the next few quarters.

Given the scarcity of external capital sources many North American service companies do not currently generate sufficient cash to organically fund investment in new equipment innovation and maintenance, let alone generate sufficient returns. Internationally, multiple years of service company. CapEx reductions should limit equipment availability we expect increasing demand and tightening equipment capacity will lead to higher prices. Pricing is beginning to return in North America now and is expected to lag internationally where contract durations are longer.

I know the positive macro outlook I just described is a case for the rising tide lifting all boats however what matters is how Halliburton is positioned to outperform in this market. The improving macro environment, marks the first time in a long time that we see an increasing level of customer urgency and they pivot back to what creates value in our industry and this reinforces the power of Halliburton's unique value proposition.

Throughout the downturn Halliburton doubled down on our value proposition to collaborate and engineered solutions to maximize asset value for our customers. We continue to invest in technology both digital and hardware that maximizes value per barrel of production.

We are expanding in new market segments. We are uniquely positioned in North America as the only integrated service company. Our collaborative culture and engineered solutions create sustainable competitive advantage setting Halliburton up to move from value creation, the value capture. Here are a few examples of how Halliburton creates and captures value through our digital technologies.

We are accelerating the deployment and integration of digital both with our customers and internally it creates technical differentiation contributes to higher margins and drives internal efficiencies. Over the first six months of this year. We grew the total user count on our energy, public cloud, by 70% and cloud revenue now constitutes almost 20% of our overall software revenues.

We believe that this shift from on-prem to cloud software solutions drives faster growth. It also allows us to expand our revenue base with the same customers as we add new cloud native applications and increase the number of users within the same operator digital technology High value remote and autonomous operations we see steady growth of our remote monitoring of open-hole wireline operations, for example, this past quarter we deployed virtual remote login capabilities on a remote location in Continental Europe utilizing a Well Site specialist in Norway to remotely operate Downhole Tools. Virtual remote Logging allows us to place highly specialized personnel at regional hubs rather than in the field, which leads to better resource utilization fewer personnel at the well site less HSE exposure and higher margins. We also deploy digital and automation in our drilling operations across the globe. Both on discrete and integrated contracts. Over 75% of our increased drilling system runs our fully automated today and we expect all runs to have some automation by the end of this year.. Across Europe and Eurasia, we increased the number of automated jobs five-fold since the beginning of this year. Drilling automation directly translates to top-tier customer performance. For example, over the last two years. It allowed us to improve the rate of penetration by approximately 25% on the Middle East lump sum turnkey project and on another integrated contract in the North Sea. Moreover digitalization and automation improve the resource efficiency of our own operations. In the second quarter on an ENOC project in Russia. We reduced rig site personnel by 40%. Separately for an IOC in the Caspian. We captured cost efficiencies through using our remote operation center to monitor and control drilling jobs. Halliburton's differentiated Drilling Technologies penetrate the market and deliver results for our customers. Our multi-year investment in Drilling Technologies is paying off. And we believe we are on the right path to outgrow the market as international drilling activity ramps up. Our Drilling Technologies delivered top quartile performance on discrete contracts and form the core of our integrated project management offering. This past quarter on a challenging, gas project on Russia's Yamal Peninsula the Halliburton project management team drilled eigth horizontal wells 6 days ahead of plan with zero HSE incidents. In close collaboration with our customer, we maximized drilling performance and accelerated the operators production. And lastly we deployed digital solutions to optimize production. In the second quarter we want to contract that highlights the enormous opportunity for digital adoption in the Middle East. After many years of collaboration with Halliburton on its digital transformation journey Kuwait oil company expanded our automated production management contract in north Kuwait to all other assets in the country. We used decisions based 365 Halliburton's cloud-based subscription service for E&P applications to automate work processes and accurately plan, forecast and optimize production throughout KOC's portfolio. We are also expanding in new market segments. We expect to benefit from the significant growth potential of our specialty chemicals and artificial lift businesses, both in North America and internationally. As Halliburton increases participation in these new segments. We believe we will enjoy unique growth opportunities that are margin accretive and longer cycle. I'm pleased to announce that in the second quarter Halliburton was awarded a seven-year Production Chemicals contract with a large IOC in Oman. Products for this new contract will be manufactured in Halliburton's new Saudi chemical reaction plant scheduled to open later this year. The strategic location of this plant will allow us to manufacture and sell specialty chemicals two other new customers throughout the region. In North America, we recently expanded our footprint in the downstream process and water treatment chemicals business through awards of two separate five years specialty chemicals contracts from large refiners on the Gulf Coast. In our growing international artificial lift business earlier this month, we completed the first installation of our ESP contract in Kuwait. We believe this contract gives us scale in the region that will allow us to profitably grow our artificial lift business in other key markets. Finally Halliburton has the broadest market exposure because we remain the only integrated service provider active in both North America and international markets. I believe this unique position allows us to capitalize on the double-digit growth equipment tightness and resulting better service pricing in both markets. In the international markets. We expect that Halliburton's differentiated drilling equipment capacity tightens first. Over the next few quarters as large tenders soak up capacity, I expect to return to the pre-pandemic environment when pricing improved in certain markets. In North America specific equipment categories are already tight today there is a high demand for low emissions frac equipment and the supply is limited. Halliburton leaves the market and low emission solutions today and that gives us a structural pricing advantage to further maximize value in North America. Halliburton showcased our market leading low emission solutions, at a recent event and and Oklahoma over the course of five days. Several hundred people from more than 40 operators came to see our electric and dual fuel equipment displays and operational demonstrations, including our 5,000 horsepower Zeus electric pumping unit, our new ExpressBlend blending system, (inaudible) electric wireline unit, the electric tech command center and an effective power generation solution. They didn't just see R&D plans and prototypes. Instead they witnessed functional job ready equipment that works for our customers today and deliver unprecedented fracturing performance and reduced emissions. The Duncan event also showcased our SmartFleet intelligent fracturing system. SmartFleet marries our digital capabilities and fracturing expertise to do what was not possible until now give customers control over fracturing performance in real time. It sets us apart from the rest of the hydraulic fracturing market and solidifies our industry leadership and intelligent fracturing. In the second quarter, we deployed the two IOC customers in two different US basins with excellent results. Operators achieve more consistent fracturing placement on every stage with improved cluster uniformity and management of offset frac hits. SmartFleet paired with our premium low emissions equipment creates a powerful combination of Halliburton's leading technologies to deliver superior Production results reduce environmental impact and drive a strong margin differential for Halliburton. We believe that our unique value proposition combined with customer urgency and equipment tightness in the US and international markets will improve pricing for our differentiated equipment and services as our equipment reaches sustained levels of higher utilization in North America we are now moving from passing on inflationary cost increases to setting net pricing higher and we expect this trend to accelerate into 2022. Internationally, pricing will take longer to catch up to North America and will first manifest itself on discrete contracts and underserved markets. We expect large tenders to remain competitive. But our strategic priority is clear deliver profitable growth as the recovery unfolds. We expect improved pricing higher utilization and our significant operating leverage will deliver strong incrementals for Halliburton in this upcycle. In the face of both current and expected demand increases. We remain focused on improved returns and capital efficiency and expect our overall capital investment to stay in the range of 5% to 6% of revenue. Now let's step back for a minute and think about what this means for Halliburton. My remarks often focus on the practical view of the near-term but I also have conviction about Halliburton's performance in the early innings of this up cycle. Based on the market assumptions outlined earlier, we expect revenue to grow at a mid-teens compound annual growth rate over the next two years. We also expect operating margins to expand by about 400 basis points by 2023 and thus return to 2014 margin levels. We are committed to driving significant free cash flow and returns for our shareholders as this multi-year up cycle unfolds. This earnings power results from the execution of Halliburton strategic priorities. I'm confident that our focus on technology differentiation digital adoption and capital efficiency positions us for profitable growth internationally and maximizing value in North America. Now I will turn the call over to Lance to provide more details on our second Quarter financial results. Lance?

Lance Loeffler {BIO 19748103 <GO>}

Thank you, Jeff and good morning. Let me begin with a summary of our second quarter results compared to the first quarter of 2021. Total company revenue for the quarter was $3.7 billion and operating income was $434 million, an increase of 7% and 17% respectively. Higher equipment utilization and our significant operating leverage supported these strong results as rig counts moved up globally in the second quarter.

Now, let me take a moment to discuss our division, results in a little more detail. Starting with our Completion and Production division, revenue was $2 billion, an increase of 10% while operating income was $317 million or an increase of 26%. These improvements were driven by higher activity across multiple product service lines in North America land improved cementing activity in the Eastern Hemisphere and Latin America, increased completion tool sales in the Middle East. The North Sea and Latin America as well as higher well intervention services in Saudi Arabia and Algeria.

These improvements were partially offset by lower stimulation activity in Latin America. In our Drilling and Evaluation division, revenue was $1.7 billion, an increase of 5% while operating income was $175 million or an increase of 2%. These results were driven by improved drilling related services and wireline activity across all regions, along with increased testing services in the Eastern Hemisphere. Partially offsetting these improvements were reduced software sales globally.

Moving onto our geographic results in North America revenue increased 12% primarily driven by higher pressure pumping services drilling related services and wireline activity in North America land as well as higher well construction activity in the Gulf of Mexico.

Partially offsetting these increases were reduced software sales across the region. Turning to Latin America. Revenue was flat sequentially. Primarily driven by increased activity in multiple product service lines in Mexico. Higher fluid services in Brazil as well as additional completion tool sales in Guyana.

These results were offset by lower stimulation activity in Argentina, Mexico and Brazil decreased software sales across the region and lower project management activity in Mexico and Ecuador. In Europe, Africa, CIS revenue increased 7% resulting from increased activity across multiple product service lines in Russia. Norway Algeria and Ghana these increases were partially offset by lower software sales across the region and lower activity in Nigeria.

In the Middle East Asia region, revenue increased 5% resulting from improved activity in multiple product service lines in Saudi Arabia. Improved well intervention services across the region. Increased drilling related services in Oman. Higher completion tool sales in Kuwait. Improved well construction activity in Australia, and increased pipeline services in China.

These improvements were offset by lower software sales across the region reduced project management activity in India. And lower overall activity in Bangladesh. In the second quarter. Our corporate and other expenses totaled $58 million. For the third quarter, we expect our corporate expense to remain largely unchanged. Net interest expense for the quarter was $120 million should remain flat for the 3rd third quarter we remain focused on reducing our leverage in the near term and recently announced the redemption of our remaining 2021 senior notes at par or ahead of schedule in August using cash on hand.

Which should reduce interest expense beyond the third quarter. Our effective tax rate for the second quarter came in better than expected at approximately 22% benefiting from several one-time discrete items. Based on our anticipated geographic earnings mix, we expect our third quarter effective tax rate to be approximately 25%. Capital expenditures for the quarter were approximately $190 million and will continue to ramp up for the remainder of the year.

However, we will stay within our full year target of 5% to 6% of revenue. Turning to cash flow, we generated $409 million of cash from operations and $265 million of free cash flow during the second quarter we believe that our year-to-date and expected earnings performance for the remainder of the year, combined with efficient working capital management should result in a full year free cash flow of approximately one $1.2 billion.

The growth in earnings outlook to Jeff laid out positions us well to grow our free cash flow over the next couple of years. Now let me turn to our near-term outlook in the international markets. We expect a steady increase in activity as the rig counts continue to recover. In North America we anticipate modest pricing improvement and continued activity momentum in both completions and drilling but sequential activity growth will be slower than in prior quarters.

A - Jeff Miller {BIO 17768856 <GO>}

So look, I think that we're looking at today is the macro, when we talk to our customers, particularly publics, they're going to do exactly what they've said they're going to do and I think we see that playing out. But we also have a good view of the macro in terms of supply and demand and I think from that perspective the planet will demand oil, where does it come from. Clearly, we've got line of sight to improving activity internationally I describe that primarily within IOCs and yes, I think that it's, it's not ZEAL.

Its steady march to produce more barrels. And then I think that the call back on the US is simply going to be that that under investment that we've seen for a number of years. Internationally, it doesn't just spring back into action, and I think that's very positive for North America. So from a customer perspective, obviously the privates, the privates are much more opportunistic around a supportive oil price. So we see quite a bit Of activity and outlook from that.

Q - James West {BIO 7351884 <GO>}

All right. All right. And then as we think about the returns on the assets that you are putting into the field right now we're probably at suboptimal type of return levels that you need pricing to go up. And so what, what are the levers or how quickly do you think pricing can move in this market to get, get back to what you did would want to achieve to drive returns higher?

A - Jeff Miller {BIO 17768856 <GO>}

Well James. It's a process and it's probably multiple iterations, but I think are saying net pricing to a certain degree today in the US slow going. But moving and as we work through into 2022, I expect that continues to accelerate internationally. I think it takes on the same type of dynamics that we saw in 2019 where markets, individual markets see tightness see pricing large tenders remain very competitive and from our perspective that was that worked well for Halliburton in 2019 and into the first quarter of 20 and we've been very clear I think about profitable growth.

And so I think that's key, when I think about growth internationally. The keyword there being profitable growth. And so that means that, and we see multiple years of growth in front of us. And for that reason, we want to be deliberate about how we put equipment to work and make money.

Q - James West {BIO 7351884 <GO>}

Right. All right. Got it. Thanks, Jeff.

A - Jeff Miller {BIO 17768856 <GO>}

Thank you, James.

Operator

Our next question comes from David Anderson with Barclays. Your line is open.

INITIAL DRAFT

Bloomberg Transcript

Q - David Anderson {BIO 6875231 <GO>}

Hey, good morning, Jeff. So clearly very bullish comments looking out over the next couple of years. I was, wonder if you could talk about maybe some of the signs that you're seeing on the international side, particularly with the Middle East NOCs. I know you've talked about increased completion tool sales from artificial of contract, some other tenders and yesterday Aramco suggest maybe shifting $6 billion more upstream.

I was just wondering when you start to see this to inflect and what does it come through. We haven't seen the rig count, pick up the 3Q guide indicates sort of a similar pace of activity from second quarter, but the same time, Middle East, feels like it should be leading that double-digit growth that double-digit guidance next year. I wonder if you just help me kind of understand the trajectory. Maybe it's obviously not a very opaque or it's more of an opaque market is help us kind of see what you're seeing in that part of the world.

A - Jeff Miller {BIO 17768856 <GO>}

Yeah, I mean what we see is, let's say broadly Middle East adding adding activity adding it sort of as we speak, but more so focused towards next year. So I think that we see well, I think, second half to second half we're going to be up probably mid-double digits for 2021 versus 2020. So where does that come from, I think that that alone increasing and we see that sort of across the Middle East, but we also see it in Argentina--and Argentina. As an example, we see it in other parts of the market and so I think that that gets traction and continues to get traction as we go further into 22, but at the activity that the demand signs are there now.

That we're seeing and I think we see growth. But I think that continues to accelerate as we get into 2023, but it doesn't necessarily overcome all of the under-investment. So I think that there is work to be done to if you to grow that business and they buy for operators to grow production. I think moving see signs of growth. Now, but I think it will be more pronounced in 22. I know we described, 21 is a transition year. So we still see COVID slowdowns in market.

Yeah, there is a number of rigs that are working because they are not staff today, not by us, but just in general. And so that type of disruption is weighing down on things a bit but I fully expect this to work through that through the balance of 21.

Q - David Anderson {BIO 6875231 <GO>}

And that's good to hear. Kind of a different topic, I was. Wanted to ask about kind of some of the inflation that maybe you're seeing on the North American side particularly maybe if it impacted your C&P margins at all. This quarter, I know you're not really seeing any net real net pricing right now, but I'm just kind of curious what the E&Ps are seeing in terms of inflation. Are we talking like 5% you stays and sort of around that same question I'm wondering about labor if we do see this increase next year in E&P budgets and assuming completion crews are added over the next 12 months.

A - Jeff Miller {BIO 17768856 <GO>}

Good morning, Scott.

A - Lance Loeffler {BIO 19748103 <GO>}

Morning. Morning.

Q - Scott Gruber {BIO 6761975 <GO>}

So I wanted to get some more color on the encouraging pricing trends here in North America. So the, the net pricing that you're garnering is that going to impact margins much in the second half. I asked because you, when you look at the 3Q guide the embedded incrementals look to be on the order of 20% and I would just think something greater than that. It is really having a big impact is there just a time lag here or are there other offsets maybe on equipment sales what you do.

We just really need to see a little bit, a little more activity growth to see pricing take a bigger late higher into 22.

A - Jeff Miller {BIO 17768856 <GO>}

Yeah, as I said, it's not across the board. It is a process, but we are seeing net pricing in certain pockets and certain things today, and I expect that that accelerates as I said, into 2022. But clearly, let's say, ESG friendly equipment that is in very short supply. We have a leading position and dual fuel electric Tier 4 also and so in all those categories. That's what the market demands, and that's an structurally because of our large footprint there. We have a structurally differentiated position but that equipment is everywhere in that equipment is some under contract, some is not and is moving.

And so the, but I think what's important At this point is that we're negotiating negotiating up and not down. And that's sort of a different dialog than what we've had and that's what we're seeing today. So does that, do you see all of that in Q3. Absolutely not. But what you do is you see us on a journey now that's different than the one that we've been on and that's where we are.

Q - Scott Gruber {BIO 6761975 <GO>}

Thats great to hear. Thank you. And then turning to the digital contract wins, which is great to see public question there on the impact on margins. First, just so we can dimension it give a digital revenues margin all flow-through D&E or when you have Completion and Production apps do some of the hit C&P and then more importantly, how do we think about the real timing and magnitude of the benefit to margins, is there much of a benefit during the second half through the initial deployment and scaling up in places like Kuwait or is it more to come in 22 and 23 and then you particularly for D&E, it's been a segment where you guys have been pushing to structurally this margins over the last couple years.

How does the, how does the digital wins in the digitization of the industry and Halliburton participation really push the--where the D&E margin to go on a more normalized basis as we get deeper the recovery?

A - Jeff Miller {BIO 17768856 <GO>}

Thank you. Yeah, I think about digital digital margin impact is across the business obviously the software sales and the the cloud native apps are in D&E, but more broadly Digital capability affects the whole business and so that's behind our answer products so tools like earthstar amd our SmartFleet all of those are a byproduct of having digital capability in the company. In fact capacity to develop software at scale is pretty unique and that is what allows that to happen.

The third way we consume software in this has an impact also on the entire business is the ability to concern the solutions ourselves and reduce our own costs. So I would argue, a large part of our ability to, for example, last year reduced the roofline by 50% was rooted in our ability to do things digitally that removes many steps and change the processes and took people out.

And so that's why I'm careful how we describe that I think that clearly, it's a contribution to D&E. But I would say that the contracts we've described all good contracts but they your ramp up by ramp up, they get started. It's a consultative process and so I would expect later this year and really more so into 22 and beyond. And I think these build one on top of another and become very sustainable over time.

Less of a sort of pop pilot wants but sort of building into larger projects over time. Yeah.

Q - Scott Gruber {BIO 6761975 <GO>}

Great. I appreciate the color. Jeff, thank you.

A - Jeff Miller {BIO 17768856 <GO>}

Thank you.

Operator

Our next question comes from Ian McPherson with Piper Sandler. Your line is open.

Q - Ian Macpherson {BIO 15106867 <GO>}

Hey, good morning, Jeff and Lance. Thanks for taking my question. So the one question I had, Jeff, is when you look at double digit trajectory for a synchronized expansion for North America and international, just given the the strong demand that OPEC Plus has over the oil market over the intermediate term, what type of call on US production growth, are you contemplating which underpins North American outlook for the next couple of years.

A - Jeff Miller {BIO 17768856 <GO>}

Well, we think that some of those we've seen over the last couple of days. I think lays out a path for OPEC and so that's to a certain degree defined. If we look at pent-up demand for oil at least today the, if we look at the pent-up demand that we see for oil today, if we're 98 million barrels a day. Now the economy feels more than 2 million barrels shut in. To me, in fact probably 4 million barrels consumed in aviation alone. And so I think there is a normalized level of Of spare capacity that's expected. So then when we think. Okay. North America what happens there.

Well, we're up 10% year-on-year and I think the expectations that production is largely flat for this year. yeah, I would expect that there would be a Call of is at 500,000 barrels, some number like that some level of growth that would be called on in 2022 that the price clearly supports, which would then drive more activity for us. Certainly. And we have to, in that mix is stemming the decline curve that is always working on North America production. So those are the things that underpin our outlook.

Q - Ian Macpherson {BIO 15106867 <GO>}

Got it. Thanks, Jeff. And then staying on the, on the domestic pressure pumping side obviously beginning to see some of the smaller competitors announced firm plans and sort of abstract plans for renewing their fleets with clean fleet lot different iterations of it and your view is that coming earlier than you would like to see it or do you think that the market is ready to support the pricing and the returns for that

Equipment at the scale that we've already seen over the last few months and and do you, should we expect Halliburton within your 5% to 6% CapEx envelope to march along at that same industry cadence with with nuclear fleet investment?

A - Jeff Miller {BIO 17768856 <GO>}

Well, look, we always look at. We're fortunate today that we have one of the youngest fleets in the market and, but as we replace equipment. We also have a large fleet. And so as we systematic Lee replace equipment. We have a choice to make. So what type of equipment do we replace it with, and it's a combination, generally of electric or dual fuel. But I think that our steady drumbeat of replacements and within our 5% to 6% of capital spend, we were able to meet meet demand and and also at terms that are adequate and but I think those 2 things have to be in place.

Fortunately, we're in a position where we are able to deliver those things today I think today, but the day and over that the near-term with from operations remains to be seen the pace at which all of that can happen in the market, given where sort of broadly that market stands today in terms of return, so without the returns is not, we wouldn't be investing in these types of equipment Equipment at all. Fortunately, we're in a position to do so and do it ratably along with our sort of planned replacement cycle.

Q - Ian Macpherson {BIO 15106867 <GO>}

Super. Thank you, Jeff. Appreciate it.

A - Jeff Miller {BIO 17768856 <GO>}

Thank you.

Operator

Our next question comes from Neil Mehta with Goldman Sachs. Your line is open.

Q - Unidentified Participant

Thank you. Thank you very much and congrats on a good quarter here. I have a really high level question, it's been a top 10 years for the energy sector, but it's been an even tougher period of time for oil services relative to the rest of energy just Jeff As a leader of this industry. What do you think the key is to track the generalist investor back into this vertical within the space.

Do you think it's about earnings execution is about returns on capital or is it about returning excess capital to shareholders. So return of capital.

A - Jeff Miller {BIO 17768856 <GO>}

Well, they, it has to be all three of those. But I think it starts with some clarity around what is the trajectory over time that sustainable as opposed to all of the ups and downs that we seem to have had sort of intra-period gyrations and I think was shaping up today. As I've described it is a more sort of predictable, sustainable trajectory and that's what we see out over the next couple of years and really beyond that just because, I think we've been through a lot of the over-capitalization there has been under investment for a long enough period of time, particularly in the resource that as demand recovers, which it will recover.

I think there is a solid opportunity set for our services. Now within within that, obviously I have a view that and believe firmly that our competitive positioning is different. Also, and because of that Halliburton's any has Tools whether it's our value proposition. Our technology or sort of our portfolio and how it's placed to maximize value in North America, which we've always been clear on, we want to maximize value in North America and grow profitably internationally

And I think both those macros are set up perfectly for for doing that and so as a generalist, there is some clarity around where we're going, we've got some track record of where we've been, where we're going and I think that sets up well for a generous generalist investor.

Q - Unidentified Participant

Yeah. And so then the follow-up on that, on return of capital. If you look at the energy sector, S&P energy sector trades at a 4.5% dividend yield, how do you think about Halliburton's value proposition on a multi-year basis around return of capital whether through giving dividend or through buybacks, do you ultimately need to be offering a total return of capital yield that's far in excess to the market, given the questions about the terminal value of the business.

A - Jeff Miller {BIO 17768856 <GO>}

Well, I think, look I think Neil. I think it's a, it's a great question and I think that we're going to continue to reevaluate what it means for us in the near term as we continue to grow into this recovery. We certainly believe that we need to improve those yields today on a dividend basis, but we're going to continue to look at and get comfortable with the forward free cash flow profile.

A - Lance Loeffler {BIO 19748103 <GO>}

What we think that this business we believe can generate in these out years that Jeff discussed, but clearly we believe it requires improvement from where we are today.

A - Jeff Miller {BIO 17768856 <GO>}

Then maybe one follow on to that. Neil, the strategically, we have changed the cash flow profile of our business and that is the shift from 10%, 11% of revenues going into capital down to the 5% to 6% but what that does is that Halliburton up to do those things. And so I think it's our view and the change in our cash flow profile certainly aid that process.

Operator

Thank you. Our next question comes from Aaron Jayaram with JP Morgan. Your line is open.

Q - Unidentified Participant

Yeah, good morning. My first, my first question relates to just the activity mix in the US, the privates, have added more than 70% of the incremental rigs since the activity bottomed mid last year. I guess my first question is, what is your expectation around the mix of the public company activity next year once some of the OPEC barrels of returned. And do you think that a higher mix of public company activity is are you different about that or do you think it's helpful to your revenue growth and margin opportunities relative to industry next year.

A - Jeff Miller {BIO 17768856 <GO>}

So look, I think we can, we will always look for the best return opportunity for us. I'd say, operators have not said anything about next year, and I'm not going to project what they might say I think I have a we can see what the demand sort of looks like to us as we look out into next year, but I also think that every operator will make them around decisions around how they deploy their capital overall a supportive commodity price, which we see create headroom for our clients to do work and return cash to their shareholders which is important for them to do.

So. I think the improving commodity price and the structural sort of support that we will see in the commodity price makes all of that work as we go into 2022 stay tuned.

Q - Unidentified Participant

Got it, got it. I just my follow up we had a dynamic, particularly in the US were budget exhaustion has led to some frac holiday is, which is obviously been a headwind. How are you. How is, Halliburton looking to mitigate that risk. As we approach the back half. And the fourth quarter. I can kind of given that dynamic?

A - Jeff Miller {BIO 17768856 <GO>}

Well, look, I think operators are going to do exactly what they said they would do, and so we really haven't seen budget exhaustion at this point haven't talked about it and I think that is because operators are relatively doing exactly what they said they were going to do. So I don't anticipate that we see any of that our much of that this year.

And I'd say the other thing that we've done and we've done a lot of work to variabilize our business such that when we see slowdowns are holes or anything else we're able to respond to it very, very quickly as opposed to how we might have done it in the past and that all is process change in really philosophy change, but it's working quite well and so I think we'll have a solid sort of working through the balance of the year just because of clarity that our clients have and providing to us.

Q - Unidentified Participant

Great, thanks.

A - Jeff Miller {BIO 17768856 <GO>}

Thank you.

Operator

Our next question comes from Connor Lynagh with Morgan Stanley, your line is open.

Q - Connor Lynagh {BIO 19713242 <GO>}

Yeah. Thank you. I wanted to return to the multi-year outlook, you guys gave, and basically what I'm wondering is, certainly, I know you want to stick to the range that you've put out there for capital expenditures. But I would. I would assume there is a certain degree of growth investment required to realize that. So I was wondering if you could discuss just where you plan on allocating capital with some of the big areas that you think are versus the priorities within the business over the next couple of years here.

A - Jeff Miller {BIO 17768856 <GO>}

Yeah, well, look, I think that as we look out, I believe that we've got the opportunity to meet those expectations within the guidance that we provided. With respect to CapEx, I think there is growth CapEx in that sort of 5% to 6% range that we provided field, for example, if I look back over the last five years. Asset turns have improved by 50% and that strong improvement. But this is back to my commentary around strategically approaching capital efficiency.

net of cash was approximately CAD1.1 billion and our total liquidity position was approximately CAD500 million excluding letters of credit.

Our net debt to trailing 12 month EBITDA ratio was approximately 5.8 times and our average cost of debt is 6.3% we remain in compliance with all our credit facility covenants. In the second quarter with an EBITDA to interest coverage ratio of approximately 2 times.

During the quarter, we reduced total debt by CAD23 million and year-to-date debt reduction is CAD32 million over halfway to meeting our debt reduction target range of CAD100 and CAD125 million for the year our capital allocation program remains substantially weighted to debt reduction and we remain on track to meet or exceed our long-term reduction target of CAD800 million between 2018 and 2022 where we have already reduced debt by CAD602 million since the beginning of 2018.

For the remainder of 2021, we expect to continue generating free cash flow through

Operator

Patients with higher activity improved pricing and only CAD22 million of cash interest do, we expect cash flows to be robust in the second half. Supporting further deleveraging.

For 2021. Our guidance for depreciation in G&A before share-based compensation are CAD280 million and CAD55 million respectively. As a result of our recent debt refinancing our run rate. Cash interest expense is less than CAD80 million and we expect it to move lower as debt pay down should continue in 2021.

Carey T. Ford {BIO 18294352 <GO>}

Finally, we expect our cash taxes to remain low and our effective tax rate to be below 10%. With that, I will now turn the call over to Kevin.

Kevin A. Neveu {BIO 5564746 <GO>}

Thank you, Gary. and. Good afternoon. I'll now take a few minutes to discuss the strong recovery developing our North American businesses and update you on our progress towards our 2021 strategic priorities.

But before I start, I want to reflect that the last year has been last year and a half has been extremely challenging for industry, especially the people who work here Precision to pandemic health challenges the lockdowns the industry layoffs, and the early retirements, and the increased individual workloads have taken a huge personal toll our people.

Our field operations remain fully staffed and unavoidably working in close contact but if we manage the pandemic challenges on the job and I hope exceptionally well over the last two months. We are fully our corporate offices in Houston in Calgary. And I think our people for the excellent work they performed in their roles remotely over the past year, and I appreciate the challenges. They continue to face every day.

We are in the beginning stages of what's emerging is a strong industry recovery and we rely on the hardworking loyal Precision team to execute our business support our customers and help drive the results, our investors and stakeholders expect. While Carey, fully covered off our recent debt financing activities. I'll just add that I'm extremely pleased to have substantially resolved our maturity profile lowered our interest carrying expense and maintained our strong liquidity, all while continuing to make excellent progress towards our, both our short-term and long-term debt reduction targets.

We believe that reducing our debt levels and bringing our leverage level below two times EBITDA will create substantial value for investors. It should be clear now than ever before that our scale-based business model utilizing high value long-life assets coupled with highly skilled crews and leading digital technologies creates a strong full cycle free cash flow profile and the asset base will require minimal capital and reinvesting for the foreseeable future.

So turning to our regional markets. I believe the rebounding customer demand, we see in Canada in the Canadian segment has broad implications as leadings indicator for what we expect to develop in the US. From a high level Canadian customer demand has returned to above pre-pandemic levels even during the second quarter, our Canadian drilling activity while tripling last year's level.

Unidentified Speaker

Was in line with 2019 in our well service business, second quarter activity was over seven times what we experienced last year also in line with 2019 activity levels. Now several weeks into the third quarter we see demand levels trending substantially higher than 2019 and I'll come back to that in a few moments.

Looking closer at our Canadian customer mix, while private equity producers play an important role over 2/3 of the demand we see comes from publicly listed producers. This group has seen has experienced several years of operating within capital constrained in fiscally disciplined framework.

They've been focused on debt reduction and return of capital to shareholders. Since the middle of the last decade and driven cost efficiencies through all aspects of their business models. Additionally, we've seen several key consolidating transactions. Our customer space that further buildup up scale and efficiency.

And now with the improving commodity fundamentals. The firm AECO gas and Western Canada Select oil prices and resilient NGL pricing. They have responded to quickly but modestly, increasing drilling activity, while remaining highly capital disciplined. This modest increase in spending has a meaningful impact when multiplied across the full producers producer space.

I'm confident we'll see a similar trend emerge in the US as public producers as the public producers older producer hedges roll off at a replaced with the current strip and those customers find a path to balanced modest growth with sustained shareholder returns.

Currently, our Canadian drilling rig count to 52 operating rigs compares to 13 this time last year and exceeded both 2019 and 2018 levels. We mentioned in our press release that we have several more rig activations plan through the third quarter and should see activity trend into the upper '50s later this quarter.

With the potential for additional rig activations in the fourth quarter as our customers prepare for a busier 2022 unusually we expect Precision's Q3 total drilling days will exceed the Q1 winter drilling season. The only other time I've seen this happen was during the 2010 recovery following the global economic recession.

That slowdown pales in comparison to what we've experienced over the past 18 months. Early in July, we agreed with the customer to a long-term contract, which includes the cost to mobilize a Precision Super Triple rigs and Colorado to Northeastern BC, further strengthening our market position in the Montney play.

I think have additional opportunities for SG 1200 rig redeployments to Canada as our customers look to a 2022 drilling budgets. labor shortages have emerged across the Canadian oil service industry has a serious challenge we are finding that many people have left the industry and reluctant to return the East Coast commuting workers are not able to easily travel and the pandemic related unemployment insurance programs.

Similarly discouraged workers from reentering the workforce at least for now. We believe that recruiting and training employees of the core precision competitive advantage. It will ensure that we sustain a strong market position.

Analyst

This recovery continues for you to take away is that the labor tightness a significantly impacting the service industry and providing a meaningful backdrop for rate increases.

Kevin A. Neveu {BIO 5564746 <GO>}

We began those price increase discussions with our customers. During the second quarter and increased rates on all rate classes CAD700 -- above any cost inflation impacts marching our rates back to positive net income territory is the key objective of our sales team and we believe this will be possible with the rate increases, which began the spring and we'll continue as pricing discussions commenced in the fall for the 2022 winter drilling season.

Now turning to our Canadian well service division, the recovery there is remarkable with current activity trending well above 2019 levels today we have 38 well service rigs operating compared to 29 in 2019. We expect this demand to remain strong through the next year. This healthy rebound has several fundamental based drivers. We are seeing

INITIAL DRAFT

Bloomberg Transcript

increased workover spending by our customers as they look to rework existing wells to improve or restore production customer demand has increased for completions activity tied to the increased drilling programs and of course the additional well abandonment work related to the government subsidized woven -- well abandonment programs are all driving demand.

Labor constraints are hitting the segment hard primarily due to the call out and less predictable day to day nature of the appointment again Precision's recruiting capabilities are largely mitigating this risk for us. yet, The labor challenge provides a strong catalyst for price increases as with our drilling group our well service sales team is charged with your pricing and margins back to positive net earnings territory.

So in summary, our Canadian business is will not require significant capital spending, other than customer funded technology enhancements and activity based maintenance capital. The segment remains well structured generate strong and increasing free cash flow for the foreseeable future.

Now I'll remind the listeners that the Canadian recovery is not characterized by massive, massive shifts in E&P spending, what we are seeing our modest incremental increases in spending by a highly disciplined group of public producers. Now turning to the US. We think the US market is poised for a similar rebound in activity requiring only modest increases in spending by US producers, our US customers have learned to operate efficiently they continue to pay down debt in the return capital to shareholders producer consolidation is underway and we believe there'll be an urgency to replace the rapidly reclining inventories of drilled but uncompleted wells.

Like Canada, we expect even a modest increase in US producer spending will drive significant and meaningful demand for our super-spec rigs like our super troubles and particularly for our Alpha digital technologies currently, we are running 42 rigs in line with our prior guidance and expect to be running 45 rigs by mid-Q3. Visibility for additional rig additions continues to emerge with bidding activity up significantly Thing idle rig reactivations is improving and our categorize this range as mid to upper teens for prospective rig activations. Now regional labor challenges and local rig availability, our emerging as pricing opportunities as we see customers' weighing rig redeployment costs versus minus black upgrades at higher rates. Now on active rig renewals with the customers either looking to retain a running and crude up rig or acquire, someone else is running crude up rig pricing is trending in the dollar plus range now. And we see this as a constructive and improving price environment across all rig categories. To date, the majority of our activity increases have been with private equity and gas focused operators. Looking forward, we're expecting a shift towards more oil-related activity than publicly traded producers, it's our view that virtually all rigs actived this year will be super spec and particularly if they are targeting development drilling programs. And I think this is a good point to shift our technology update as reported in our press release it appears we crossed the technology tipping point with our customers at the beginning of this year. The efficiency gains and predictability improvements we deliver with Alpha automation are becoming well understood and accepted by our customers and we are seeing wide scale customer adoption. Were Alpha automation days were up 30% sequentially despite the reduced seasonal activity in Canada and now with 16 commercial apps, which are alpha up revenue, almost double in the second quarter versus the first quarter. Alpha analytics is also gaining strong customer acceptance with sequential utilization also stepping up over 70%. Notably, during the second quarter we contracted three super-spec rigs on long-term basis with the new customer, a major operator these rigs will be activated during the third and fourth quarter, with four Alpha automation and Alpha apps and Alpha analytics product suite. We view this as a technology-driven market share gain clearly digital enablement is a theme, we are hearing from virtually every customer today and there's no question that our Alpha technology suite deliver strong digital value and our pricing model is ensuring that we get our share of that value creation. The second common theme we hear from virtually all customers today is regarding reducing GHG emissions. Our decision to target ESG as a strategic priority this year, if not had come at a better time. You may have noticed our announcement last week of the Precision E team a cross-functional group of experts within Precision Cast with leveraging our environmental in emission strategies. Also included was the announcement of our Evergreen environmental brand and the specific ongoing initiatives to provide reduced and zero-emission power sources for our rigs, the team has made excellent progress this year and we are very well positioned with our customers as a key service provider helping solve their GHG challenges, we also published our second Annual Corporate Responsibility Report, which is aligned with SASB and TCFD disclosure standards I recommend you go to our website

Unidentified Speaker

I'd review our comprehensive corporate responsibility disclosures.

Carey T. Ford {BIO 18294352 <GO>}

Lastly in the International business segment. As Gary mentioned activity was stable during the second quarter with three rigs operating in Kuwait and three rigs operating in the Kingdom of Saudi Arabia, we are expecting upcoming tenders for our three idle rigs in Kuwait and believe we have a good chance of success on those tenders.

This may result in rig activations later this year. These rigs will require some equipment recertifications and I would expect capital spending on the order of CAD3 to CAD5 million per rig, which we'd expect to recover inside the first few months of rig operation.

We're seeing increased tender activity in the Arabian Gulf region through several LLCs and expect this could result in further rig activation opportunities really next year. It seems a much of the rig tendering sequencing is linked to the timing of the relaxing of the oil export limits.

As always, the national oil company tender process tends to be likely but results and similarly lengthening contract terms, something we ultimately desire with the improving outlook across all of our business segments. I'll return to the people Precision who are critical to every aspect of our services.

I think all of you for your hard work, perseverance and excellent risk management, the last several quarters. So, I'll now turn the call back to the operator for questions.

Questions And Answers

Operator

As a reminder to ask a question,(Operator Instructions)Please standby. While we compile the Q&A roster. And your first question comes from the line of Ian McPherson from Piper Sandler.

Q - Unidentified Participant

Thanks, good afternoon. Gavin and Karen. Congratulations on the debt refi. That's a great to Q4 for you all financially and operationally. So good to see that I was trade Kevin by your leading edge US day rate data points just wanted to clarify, are those base day rates excluding Ala carte add-ons for the suite.

A - Unidentified Speaker

Correct. Those are based day rates for the base super triple rig excluding technology add-ons okay.

Q - Unidentified Participant

Yeah. And that's certainly improving higher than than we would have recently expected and you mentioned the consolidation of your customer base across Canada. And the US, but there's also been some consolidation that your space in Canada, which I think makes that competitive framework even probably a little bit tighter than it is in the US, are you seeing accelerating pricing power more so in Canada than in the US at this point and any would you lean further out in time to hazard where pricing is going in both markets by the end of the year.

A - Unidentified Speaker

I think that's a very good question. First of all, but the transactions for consolidation in Canada and the one in the US also haven't closed yet, but we expect them to close soon.

A - Carey T. Ford {BIO 18294352 <GO>}

I do think that brings an appropriate level of rational thinking to the market space and the way I say that is that the, in Canada, for example, the Montney play in the Deep Basin and Duvernay are our unconventional resource plays with large pad horizontal drilling, these are very much industrialized operations they require drillers of scale with high-quality technology driven assets to operate those as economically possible.

So I think this rationalization, we're seeing, we're seeing among the customer base and being echoed in the supply base is constructive it creates frankly does create a better pricing environment for our services, but probably a more appropriate pricing environment for the services we provide. But I think the core driver right now for pricing in Canada has been just industry overall demand and then some of the labor tightness, tightening up the supply side. So I think those two combinations are driving the near-term pricing.

A - Kevin A. Neveu {BIO 5564746 <GO>}

But we do expect to see very rational behavior over the long term on particularly on the Deep Basin in Canada. I think the same thing will develop in the US as that consolidation play takes place also.

Q - Unidentified Participant

That's great. Thanks, Kevin. I'll pass it over.

A - Kevin A. Neveu {BIO 5564746 <GO>}

Thank you.

Operator

Your next question comes from the line of Taylor Zurcher with Tudor Pickering and Holt.

Q - Taylor Zurcher {BIO 19106530 <GO>}

Hey, thanks, guys. Our first question, Kevin, you talked about the Canada market backdrop is clearly improved and you talked about how we might see a similar dynamic is what's going on in Canada right now eventually play out in the US in the US where we're still well below pre-pandemic levels. And so just hoping you could give us a little bit more color on the dynamics at play that you see in the US may be over the next 12 months and maybe any suggestion on timing as to when we might get back to sort of pre-pandemic type levels in the US?

A - Kevin A. Neveu {BIO 5564746 <GO>}

Taylor. I think the number one answer. I mean it's going to focus on is that the investor desire for returns and discipline is not going to go away in the US and hasn't got away in Canada. Either, but I do think what happens is that as our customer's hedges roll over into the much more constructive strip that we see today versus six months ago or a year ago. I think that's going to free up more cash flow. I think it allows additional debt repayments additional investor returns and room for modest increases in capital spending, like we've seen in Canada.

Again the pivot in Canada isn't a substantial pivot in spending. It's a modest pivot spending, but when spread among 30, 40, 50 companies you if you have 50 producers in the US had one rig that's a meaningful step-up in demand for super-spec rigs in the US. So I think you'll see a dynamic emerged in the US with modest increases in spending one rig additions here and there that across the fleet adds up to

A - Unidentified Speaker

50-60- 75 rigs maybe between now and end of the year. And that puts a very strong pull on the super-spec fleet, especially bake in kind of regional dislocations you the the Permian might have excess super-spec rigs, but most of the basins don't.

Q - Unidentified Participant

Yeah, makes sense. Good to hear. My follow-up maybe for you, Kerry. You talked about robust cash flow for the back half of the year, I suspect, with the seasonality in Canada. And as the US activity continue to trend higher that our working capital likely becomes a drag on cash in the back half of the year.

So just wondering if you could kind of butting up, how we should be thinking about that robust cash flow outlook translating into free cash flow and get into the mid point of your debt reduction range, but it would take about CAD50 to CAD60 million of incremental debt pay down.

When we think about robust cash flow should we expect CAD50 to CAD60 million as being kind of the right number to think about for the back half of the year.

A - Unidentified Speaker

Yeah. Taylor. I appreciate the question. So we don't typically give guidance for EBITDA for will give enough information. So you can calculate that. But I can I can walk you through some of the guidance, we do provide, so I pointed out, we have only CAD22 million of cash interest. In the second half of the year.

So that would be helpful to cash flow. We've given our capital guidance where we've got another CAD30 million or so that we're going to spend on capital expenditures and those will really be the two main draws of cash. The working capital build since we exited Q2 with such strong activity in Canada. Won't be the typical seasonal working capital build that we would see. We think probably it will be CAD5 or CAD10 million of working capital build and likely that's offset somewhat by used asset sales that we typically do normal course got it.

Q - Unidentified Participant

That's it from me. Thanks for the answers.

Operator

Your next question comes from the line of Aaron MacNeil with TD Securities.

Q - Aaron MacNeil {BIO 19667184 <GO>}

Hey guys, thanks for taking my questions and testing. Congrats on the new. My first question is on the rig move from Colorado the BC Montney, I assume the customer is paying for the formal but wanted to confirm, I'm also wondering if the rig already has the our automation technology embedded and if it will when it's the rate kicks off under the contract.

And then from a, from a pricing perspective, just based on the where you describe current dayrate ranges. How should we think about the pricing on this specific contract, given that you entered into a multiyear contract.

A - Unidentified Speaker

Not a short-term contract yeah, a couple of comments pretty sure the customer will identify himself if you listening to our calls, I want to be cautious with how much transparency I give out but the MOB cost

A - Kevin A. Neveu {BIO 5564746 <GO>}

Inside the contract, meaning that the customer is paying the cost of the rig is equipped with Alpha digital technologies and the customer is quite pleased with the performance of digital technologies. There will be some re-certification costs as we bring the rig back into Canada will spend under CAD102 million through the re-certifications on the rig. I think I tell them all the points if you get there. And I think answered all your questions. But if I missed one. Let me know.

Q - Unidentified Participant

Just on the was the, I guess is the pricing materially different given that is a multiyear contract versus the rates you described.

A - Kevin A. Neveu {BIO 5564746 <GO>}

I would say that the pricing is structured to give us a return on investment that we think is well above our cost of capital in the appropriate long-term range.

I mean the bottom line is not, they're not walking in a low market price. The long-term. it's a price that we're happy with and that we've negotiated carefully with the customer and delivers a good return.

A - Carey T. Ford {BIO 18294352 <GO>}

Yeah. And, Aaron. I also, we're not, we're not executing this move for strategic reasons. It's, it's, we're getting an appropriate financial return.

Q - Unidentified Participant

Should I interpret the rig moves is just a signal that there is extremely limited capacity in this asset class. Canada.

A - Kevin A. Neveu {BIO 5564746 <GO>}

I think so, I think that may I think the demand could move up further, maybe another two to four rigs into 2022 and I don't think we'll be successful at all four of those are three of

Operator

Your next question comes from the line of Cole Pereira with Stifel.

Q - Cole Pereira {BIO 22180923 <GO>}

Hey. Good afternoon everyone high growth with Gary's comments on US drilling margin. So I just wanted to be clear, you're going to see margins moving on a flat to up after Q3. So I would interpret that the additional activations coming on in Q4 in Q1 in the US are offset by higher economies of scale and higher pricing that I kind of get that correct.

A - Unidentified Speaker

Yes, you got that exactly correct. And what we've said there is that we think that margins are bottoming this summer and that probably means at some point

A - Carey T. Ford {BIO 18294352 <GO>}

And July or August is when we're going to see margins bottoms, whereas average margins in Q3 are on par was average margins in Q2.

Q - Unidentified Participant

Okay, great. I know the super helpful, thanks. And a lot of concerns about labor tightness kind of around the Canadian oilfield services market. I mean, do you guys worry at all that the labor issues might kind of put a lid on the rig count heading into Q1, or how do you think about that?

A - Kevin A. Neveu {BIO 5564746 <GO>}

Paul, I think it's going to be a struggle. And there is a number of things driving that right now the drillers have actually in pretty much every other rebound cycle. It's always been quite sharp, the Georgia[ph] found a way to restaff our rigs, I'm quite comfortable that we will restaff our rigs. I know there's probably a few PD people listening, they do network right now and are working pretty hard to find crews but between our brand and our recruiting our training, I expect we'll be successful and I don't think it will put a lid on our activity.

Obviously, if a customer wants a rig for one well for seven days. We might not do that but any kind of meaningful program we've, I think we'll build stuff up our crews for that industry-wide. I think it will vary certainly I can. I can go back to David[ph] actually. That is just let or the tougher environments. I've seen for recruiting I guess. Fortunately, our brand carries a lot of weight of out there.

Q - Cole Pereira {BIO 22180923 <GO>}

Okay, great, that's helpful, thanks. And I mean with the additional upgrade CapEx. Can you just provide a little color exactly on what that is? And with the increase in a small increase in maintenance CapEx is fair to assume that's just more robust Canadian outlook?

A - Kevin A. Neveu {BIO 5564746 <GO>}

A little hard to say. Certainly the tenders a little longer than we were thought even just a month or two ago, nothing is changing that. I think I can comment that vaccination rates in Kuwait and Saudi Arabia are extremely high, fully re-staffing offices seems to be on the agenda.

Following the current holiday right now, which just wrapped up. I think there is likelihood we can activate some rigs and quite before the end of the year, but it's, it might be in November, December and then rolling into January.

Q - Unidentified Participant

So is it the COVID issue that's preventing them from wanting the contract or is it more the current OPEC plus quarter which has is yeah.

A - Kevin A. Neveu {BIO 5564746 <GO>}

The simple answer might be. Yes, to your question, I think it's both. I think, I think it's hard to make a strategic decision international oil company when you're still operating remotely or partly remotely but I also think that they are, they understand their production depletion curves quite well they're shut in capacities and drilling activity in both countries is down for oil and they need to time the restart with when they expect their wells that they've got shut to come back on again.

So it's going to be a I think a pretty careful model but wondering those rigs back on.

Q - Unidentified Participant

No. In Saudi Aramco has a contract to build 50 additional rigs over the next, I believe 10 years. Do you think they have need for current idle rigs there or they will continue to just bring in these new wells into the, into the market.

A - Kevin A. Neveu {BIO 5564746 <GO>}

So there are tenders right now that are in the region, including some in Saudi. Some of those are IPM tenders some our direct drilling tenders is an active tender in Saudi, that we were working on for a while. I think we've got opportunities to activate silver idle rigs and that could be in Saudi, or it could be in other Arabian Gulf perimeter countries.

Q - Unidentified Participant

Okay. And do you have suite of services running

Any other international rates.

A - Kevin A. Neveu {BIO 5564746 <GO>}

No, we don't. And we've been careful to deploy Alpha where we can, we can well support. Well, we want to make sure we can go out and have 99.9% uptime, I would say that we will be ready to start introducing Alpha internationally in 2022.

Q - Unidentified Participant

Okay, great, thank you very much, Kevin. I appreciate the answers.

A - Kevin A. Neveu {BIO 5564746 <GO>}

Thank you.

Operator

Your next question comes from the line of Sean Mitchell with Daniel Energy Partners.

Q - Sean Mitchell {BIO 19870146 <GO>}

Hi guys, thanks for taking my question. I'm going to hit the hot topic here again labor. Just one more time. I want to understand as we move into the back half of 2021 and it sounds like at least according to your work and some of the work we've done. We agree with you that the rig count will continue to rise. How do you think about labor today if you had to crew one rig or two rigs versus having crew five or 10 what's the lead time for crew and a rig today versus one rig versus five rigs, for example,

A - Kevin A. Neveu {BIO 5564746 <GO>}

Yeah, Sean. So typically when we start room working with our customers will have anywhere from two weeks to a month or in the. I mentioned we have three contracts were signed in the US on those three rigs. I think one rig activates in either in late July early August. And then the next to activate month two behind that's we have a plenty of time to build those crews out.

The rig managers and drillers already booked for Precision so leadership teams are on staff right now working on a rig somewhere else, so we'll pull those guys to the rigs are being reactivated and then we'll backfill the positions that we have opened and will recruit for the positions. We need to fill. We've got a very sophisticated staffing model at a really sophisticated recruiting model we typically keep anywhere from 500 to 1000 people on kind of a call back list I'd admit we've worked our way down that call backlist a long way and now we're out recruiting the kind of be on that list.

Can I tell you that in both US and Canada? The next five rigs that we need to activate we have crew identify for beyond that we need to continue building crews up so for each market, for Canada five and five for the US. Identify crews identified leadership and able to execute beyond that will rely on our recruiting, training methods.

Q - Sean Mitchell {BIO 19870146 <GO>}

Got it. Thank you.

A - Kevin A. Neveu {BIO 5564746 <GO>}

carbon, higher value and lower carbon. Overall, I'm very pleased with our revenue quality, solid execution, enhanced market participation, both in North America and internationally, and most importantly, the translation of all of these elements into another successive quarter of margin expansion. I want to thank here the entire Schlumberger team as they continue to execute and deliver outstanding performance for our customers and our communities despite COVID impact in several parts of the world.

Next, I would like to share my view on the macroeconomic environment supporting our industry. While the rise of the COVID-19 Delta variant and resurgence of related disruptions could impact the pace of economic reopening, recent market projections continue to affirm an improving global economic outlook. Global GDP growth is now expected to approach 6% in 2021 and more than 4% in 2022, which should continue to drive a progressive recovery of oil demand. This outlook is supported by recent oil demand updates, which reflect the anticipation of wider vaccine-enabled recovery, improved mobility and additional fiscal stimulus in large economies through the second half of the year.

Looking farther out, the IEA projects that global oil demand will reach 100 million barrels per day and surpass pre-COVID levels by the end of 2022 in the absence of further policy change. With oil price at elevated levels, the supply response to this demand recovery is developing broadly as anticipated. Indeed, this combination has resulted in a call on short-cycle production as well as an uptick in long-cycle project, reflected in new FIDs and encouraging recovery in both offshore developments and near-field exploration activity through the second quarter.

In North America, this supply response is reflected in the rig count and frac fleet trends, with sustained strong growth through the first half of the year, private operators led activity growth which resulted from the acceleration of DUC completion and increased drilling activity to replenish DUC inventory. By contrast, the embrace of capital discipline by the public operators is highlighted by the rig count still being significantly below the Q1 2020 total, despite WTI price exceeding pre-pandemic levels. In this context, despite a solid activity growth outlook, we maintain our view that the North American market will be structurally smaller than in previous cycles as a consequence of capital discipline and industry consolidation.

Moving to international markets. The deficit of investment needed to deliver the required oil supply represents a sustained growth opportunity, particularly in the low-cost, advantaged basins. We remain constructive on the structural pull on international supply and the resulting activity impact. This was already visible in the second quarter with a strong seasonal rebound and offshore recovery despite the impact of COVID disruption in part of Asia and in the Middle East. This also marked the second consecutive quarter of international rig count growth.

Looking further out, we see favorable conditions for durable investment growth driven by the combination of actions by NOCs, internationally focused investment by public E&P operators and the expectation of continued supply discipline by OPEC+, all in response to the steady evolution of demand. The current pace of international tendering contract awards and increasing book-to-bill ratio support this view.

Against this backdrop, Schlumberger is extremely well-positioned, both international markets and in North America. Our market exposure is biased to accretive growth. And with a series of new contract wins, our leading digital and fit-for-basin technology portfolio, and our performance strategy, we will create value for our customers and deliver industry-leading returns.

Turning to the third quarter outlook. In North America, we see another quarter of growth, albeit somewhat moderating in U.S. land, led by private operators and horizontal oil drilling and a seasonal recovery in Canada. North America offshore will remain resilient, albeit with the hurricane season in view. Moving to the international markets, positive growth momentum is expected to continue through the third quarter across all areas. Short-cycle activity will be augmented by longer-cycle project start-up.

In this context, directionally, we expect our global third quarter revenue to grow by mid-single digits led by Reservoir Performance and Well Construction divisions, while our pretax segment operating margins should further expand by 50 to 100 basis points. With this outlook for the third quarter, we remain confident in achieving double-digit international growth in the second half of 2021 when compared to the second half of 2020.

As a consequence, and absent further COVID setback in operational recovery, we now foresee full year revenue growth both internationally and in North America, when excluding the impact of divestiture. With activity recovery ahead of us through the third quarter and strong signal of a durable recovery beyond that, we can now clearly see a path to the high end of our full year EBITDA margin expansion guidance for 2021.

Looking further ahead, the fundamentals remain very favorable, with a growing economic rebound, supportive oil prices and a demand and supply outlook all representing a set of unique conditions that will support an exceptional growth cycle. Furthermore, this cycle will be broad-based across geographies and operational environment, land, offshore, North America and particularly, international markets.

The second quarter was a strong indication of the future outlook and a testament of our restored earnings power under these conditions. In summary, I'm very pleased with our strong quarter, second quarter results across our entire portfolio, which demonstrates the effectiveness of our strategy in delivering our long-term financial ambition.

I will now pass the call to Stephane.

Stephane Biguet

Thank you, Olivier, and good morning, ladies and gentlemen.

Second quarter earnings per share was $0.30. This represents an increase of $0.09 compared to the first quarter of this year, and an increase of $0.25 when compared to the same period of last year, excluding charges. There were no charges or credits recorded during the first or second quarters of 2021. Overall, our second quarter revenue of $5.6 billion, increased 8% sequentially. North America revenue increased 11% sequentially, while international revenue increased 7%, both outpacing respective rig count growth.

Pretax operating margins were 14.3% and have now increased four quarters in a row. This represents the highest margin since the fourth quarter of 2015. Notably, margins expanded sequentially across all four divisions. This performance was driven not only by the seasonal rebound in the Northern Hemisphere, but also a favorable revenue mix as a result of increased offshore activity, new technology adoption and increased exploration and appraisal activity.

J. David Anderson

Hi, good afternoon, Olivier. So clearly, we're starting to see the international upstream market starting to pick up, as you noted double-digit increases in many countries. I noticed you didn't mention Saudi, which I would expect to start to pick up in the coming months. So when do you think that piece falls into place? And how do you see the cadence for Middle East activity through the end of this year? And kind of what does that mean for '22 growth?

I would think that kind of, at this point, I'd be surprised if growth wasn't up at least double digits internationally, especially with the positive commentary around offshore. Just wondering if you could comment, please.

Olivier Le Peuch

Yes. First, in short term, I would like to reiterate my positive commentary on the second quarter growth. It was all basins, all divisions internationally. So it was broad and inclusive of Middle East. Now in the context of the Middle East in particular, the growth was maybe more muted or less aggressive and less accretive to the overall growth than other basins. And there are a couple of reasons for that. And the first and foremost reason is relating to the supply constraints that are still outstanding on the backend, as such, muting some of the short-cycle activity that we could have expected to rebound faster.

So now going forward, there are a couple of factors that will play favorably short term and midterm. Short term, there will be a relief of some of these supply constraints that will continue to inch up the short-cycle activity, including Saudi. There is a commitment in Middle East for gas development.

And I think Qatar was the first to expand their commitment, and we have benefited greatly from that rebound in activity for the last couple of quarters, and this will extend also to a couple of other countries, including Saudi. And lastly, as we turn into 2022, we have heard some signal from a couple of countries in GCC that have signaled that they will commit to production capacity increase to fulfill their opportunity to gain share as there will be a pull on international supply.

So this will result from 2022 in combination of short cycle gas development, and long cycle across that region. And hence, they will catch up, and they will certainly be a region that will lead the activity growth and will support in second half our double-digit year-on-year H2 and next year into a strong growth going forward.

Finally, if I have to make a comment on this, I think you may have seen some contract wins and contract award in Middle East. And we believe that on top of this activity growth, we have the potential to outperform and then getting a further tailwind to our growth going forward.

J. David Anderson

So if we look a little bit further out, you've kind of talked big picture about EBITDA exceeding 2019 levels with only about 50% of that lost revenue coming back. Just wondering if anything has changed in that view, either in terms of the timing of that growth coming -- that revenue coming back or the EBITDA level? Has anything sort of changed in that kind of longer-term view that we're thinking about?

I think in the early part of the cycle, I think we will use and the industry will use the excess supply that came from the compression of activity that came for the last two years. But again, we have very much professionalized our planning and supply organization. And I think from the Cameron to the asset that we have to deploy, I think we are trying to take a long-term view and scenario-based view on the future, looking beyond the 12-month horizon, and I'm starting to prepare and put some options so that we can respond to this growth going forward. Early part will not necessarily create a tightness, but the mid-cycle for sure, before the mid-cycle, this will create the condition for tightening supply and hence, some pricing conditions.

Connor Lynagh

Thank you. I will turn it back.

Olivier Le Peuch

Thank you.

Operator

Next we go to Neil Mehta with Goldman Sachs. Please go ahead.

Neil Mehta

Good morning, team. The first question is around portfolio optimization. Perhaps you guys can weigh in on how you're thinking about the path for asset monetization, thinking Canada, maybe the Middle East? What are the opportunities? And how large could the asset sale market be for Schlumberger?

Stephane Biguet

So look, Neil, hi, we -- as it relates to the divestitures we disclosed last quarter, first, the APS asset in Canada, it's -- both are progressing as planned by the way. So in Canada, we have more than 10 parties actively looking at the information in our data room, and we plan to receive first round offers by the end of next month. Good news is that the economics keep on improving. So we are hopeful we can achieve a successful transaction.

The Middle East rigs, likewise, progressing. We are negotiating with the shortlisted bidders. We have completed their due diligence, and it's going as planned. So I think really, these are the two divestitures that we have over equity positions where we have options for monetization in the future such as our Liberty stake, but this is something we will -- the timing and the magnitude we'll look at in due time.

Neil Mehta

Yes. Great. And then I would appreciate some of the comments you made on Saudi broadly, but maybe you could just step back and talk about OPEC+, including other regions within that cartel or in the plus side of OPEC. How are you seeing activity trends here? And what role do you think Schlumberger is going to play in terms of building out capacity that they are talking about?

Olivier Le Peuch

I think, first, we have, I'll say, a privileged market position with most of the NOCs in this OPEC+ consortium. We have seen across the broad spectrum of these NOCs' activity starting to build back, seasonal rebounds playing strongly in Russia. And we expect, as I said, this short cycle to recover for the next two to four quarters as the demand will be lifted, as the constraints will be lifted, and we see that more than one or two country will actually commit to this capacity expansion. And we have the footprint. We have the relationship. We have the fit-for-basin to leverage and then to respond to this capacity buildup and this growth opportunity in those, from Russia to Middle East, particularly.

So I feel confident that these market share pursuit, that as the market comes back from '22, '23 will be giving us an opportunity to leverage our market position and move up.

Neil Mehta

Thanks.

Olivier Le Peuch

Thank you.

Operator

Next we go to Arun Jayaram with JPMorgan Chase. Please go ahead.

Arun Jayaram

Yeah, good morning. Maybe just to follow-up to Neil's question on NOCs, I guess you're seeing some positive activity trends from the NOCs. And would you characterize these activities thus far as just more regarding sustaining capital requirements? Or are you seeing any potential mix shift in terms of increasing productive capacity? And again, we did note some increases, I guess, on the exploration side in terms of your revenue base.

Olivier Le Peuch

Yes, I think as I commented before, we have to distinguish first the gas and the oil market. And on gas market, I think the activity has been more sustained, and as seen in Qatar, a significant commitment to accelerate the North field redevelopment and expansion. So that has been very positive, and we have the benefit of that exposure. And the gas remained steady and supported elsewhere.

On oil, you have a mix. But in short term, it's mostly a short cycle in anticipation of the supply constraints relief. And for two or three of the country that participate to the GCC, they have already made public commitments that they will expand, and they will participate at scale into the post rebalance, if you like, of the supply and then participate to the capture of international share of supply into 2023. So that will mean plan that will materialize from planning, from contract and from execution into 2022.

Arun Jayaram

Great, great. Olivier, you recently provided some longer-term outlook comments for New Energy citing, call it, the 10% kind of growth CAGR as you helped your clients decarbonize. I was wondering if you could give us some thoughts on maybe the baseline for that long-term forecast and areas of your Transition Technologies portfolio that you're seeing perhaps the greatest traction as we sit here today.

Olivier Le Peuch

Yes. Let me first clarify, and not mix in the same umbrella, the New Energy portfolio that we have developed with the purpose to create a new chapter beyond oil and gas to participate at scale to the energy transition from hydrogen to CCS and geo energy or lithium, as you have heard, from the Transition Technologies that we believe are very pertinent to the decarbonization of our oil and gas industry, helping our customers to reduce their footprint, CO_2 footprint, to reduce their GHG emission. And in this context, we are focusing on flaring elimination or reduction, and we are using, in particular, the Ora wireline technology to avoid returning the fluids to the surface and burn and dispose through flaring and do the reservoir characterization and testing in situ, if you like.

And that's a unique technology that has significant impact on both efficiency and on the CO_2 footprint for everyone using it. And we are looking at methane emission detection and containment. And we are looking at, as you have seen in the press release this morning, also the CYNARA CO_2 membrane that have superior performance for large acid gas treatment, if you want, to do CO_2 sequestration and capture. So you have these two aspects.

So the Transition Technologies will come more and more into play. And most of the customer I meet are asking us whether we can help them and have a conversation engagement on to methane detection, flaring or other techniques that eliminate or reduce significantly the footprint of CO_2 on every operation on their Scope 3 upstream, if you like, in addition to their Scope 1 direct emission. And then -- and that will be part of our technology growth, technology adoption in the quarters to come.

And then longer term, we will build on our New Energy portfolio that we are building. And then once we have -- continue to build this, we will grow at scale from hydrogen to CCS and bioenergy with Celsius for the heating and cooling of buildings to lithium production is the pilot that we are initiating, and the contribution from Panasonic give us the opportunity to do so. So these are two different avenue for growth short term and long term.

Arun Jayaram

Thanks for the fulsome answer. Appreciate it.

Olivier Le Peuch

Thank you.

Operator

Next we go to Tommy Moll with Stephens. Please go ahead.

Tommy Moll

Good morning, and thanks for taking my questions.

The relationship we have and the customer base we have today will be occasionally, and I think will be the sense of the CCS where our customers have the opportunity to participate or in some of the downstream operation where they have a carbon capture or blue hydrogen opportunity could be an opportunity for us to continue to work with that customer base and expand. And at the same time, some of this company are turning into integrated energy company that will also participate at scale in the same market as we do.

So that relationship will be useful, but I will more, I would say, highlight the global deployment capability. Now when it comes to capital allocation and capital deployment, I think it's very difficult to pinpoint to a specific here. I think we will look again continue to mature this venture, prepare for scale as we start to, I would say, progress on our milestones, progress on our partnership and progress on the business model and the supply chain model that are quite different from the one we experience today.

And then in that context, we'll make the appropriate capital allocation decision to be accretive to our long-term growth and to our returns.

Tommy Moll

Thank you. I appreciate it and I turn it back.

Olivier Le Peuch

Thank you.

Operator

And ladies and gentlemen, our final question comes from Marc Bianchi with Cowen. Please go ahead.

Marc Bianchit

Thank you. Olivier, you mentioned the return to 100 million barrels of consumption and sort of a share shift from North America to international where the oil is coming from. I'm curious if you think that the international activity needs to surpass 2019 levels to deliver that much oil and what you think the time line is to get there.

Olivier Le Peuch

I think in short term, the rebalance will be mostly down to the release of the spare capacity that, I think, exists. Now if you look at the current production of the U.S., which is 1.5 million barrels or about below -- in U.S. land -- below what it was in early 2020, this gap has not yet been breached. And I think I do not expect this to be breached as we exit 2022.

So there will be an increment of oil supply that we will pull on international market that the market can deliver today. But for sustainability in '23 and '24, the market will have to commit capacity. Hence, this is the reason why in Middle East and other country, you see this commitment of capacity. And this is the reason why you see the return of offshore and the commitment of FID. We have 50 FID about already to date. We expect to be 100 FID, most of them in offshore at the end of the year. This is 50% more than it was last year, and the trajectory is towards 150 -- 150% increment after that.

So now going forward and expanding beyond, I would expect within the next two to three years, obviously, with this dynamic and the pull on the international supply will create the floor of activity to reach and/or exceed the level of 2019 activity within that time frame.

Marc Bianchit

Okay. Great. Very helpful. Separately, on -- you mentioned APS a couple of times in the press release. It sounds like maybe activity has ramped a bit in Canada, where you have a bit more oil price exposure. I'm just curious how investors should think about the sensitivity to oil price from APS at this point. And then if you do have a successful transaction and sell the business, just how material of a shortfall in cash flow would that create just vis-à-vis what we're seeing right now?

Stephane Biguet

I'll take these questions. So look, the -- actually, the activity itself didn't really change, and activity here is more measured in terms of production, of course. So we did have a bit of a nice windfall on increased WTI in the second quarter from our Canada asset, but it's -- in the grand scheme of things, it's not material. In Ecuador, by the way, at this level of WTI, our tariffs are either fixed or when they are variable, they are capped. And we have passed that cap. So there is little sensitivity to oil price at this level besides Canada.

Now it makes it a very good time to actually monetize our assets, right? It's -- it has generated cash flow lately because of the oil price and the investment level we put in there. Historically, it's an asset that requires quite a bit of CapEx. And so when we close the transaction, we shouldn't see a big impact on our cash flow, and we'll get, of course, hopefully, very good proceeds from the transaction.

Marc Bianchit

Wonderful. Thank you very much.

Stephane Biguet

Thank you.

Operator

Speakers I'll turn the conference back over to you for closing remarks.

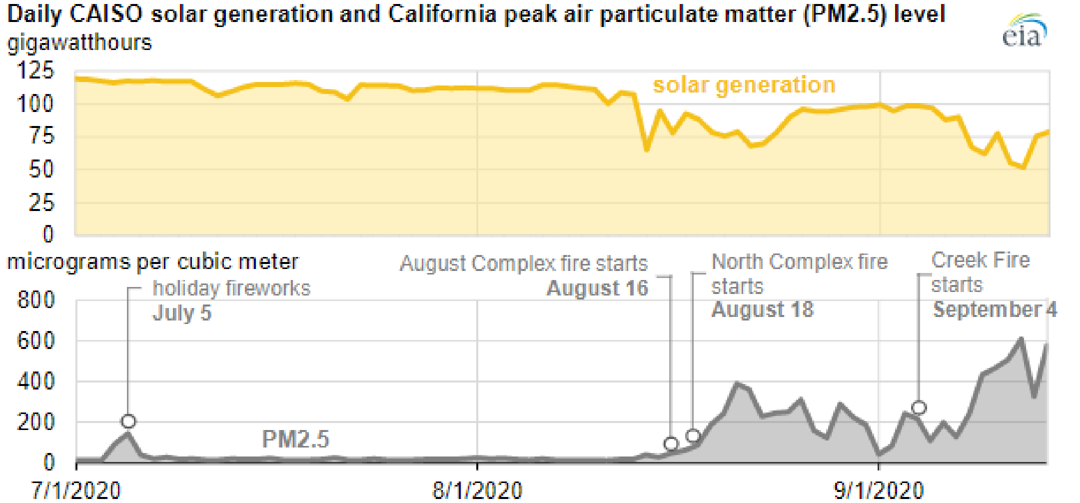
Olivier Le Peuch

Thank you very much. So to conclude the call, I would like to leave you with a few key takeaways. First, the second quarter results clearly demonstrate both the strength of our market position, particularly internationally, with sequential growth in all divisions and basins, and our significant operating leverage, resulting in more than 200 basis points of operating margin expansion internationally with all divisions contributing significant fall-through.

Second, the activity and customer trends observed during the quarter reinforce our conviction in an increasingly favorable outlook, a broad recovery across all basins and operating environments and with a much improved contribution from new technology adoption. Third, and absent further COVID setbacks impacting activity or economic rebounds, we are confident that the momentum for this up https://www.eia.gov/todayinenergy/detail.php?id=45336

SEPTEMBER 30, 2020

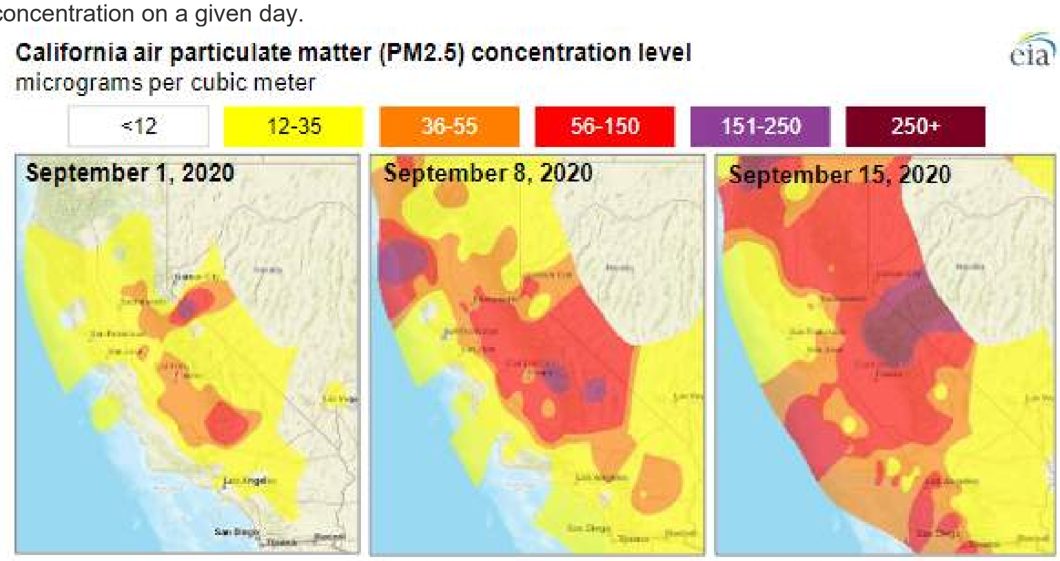
Smoke from California wildfires decreases solar generation in CAISO



Source: U.S. Energy Information Administration, Hourly Electric Grid Monitor; California Air Resources Board, Air Quality and Meteorology System
Note: CAISO=California Independent System Operator.

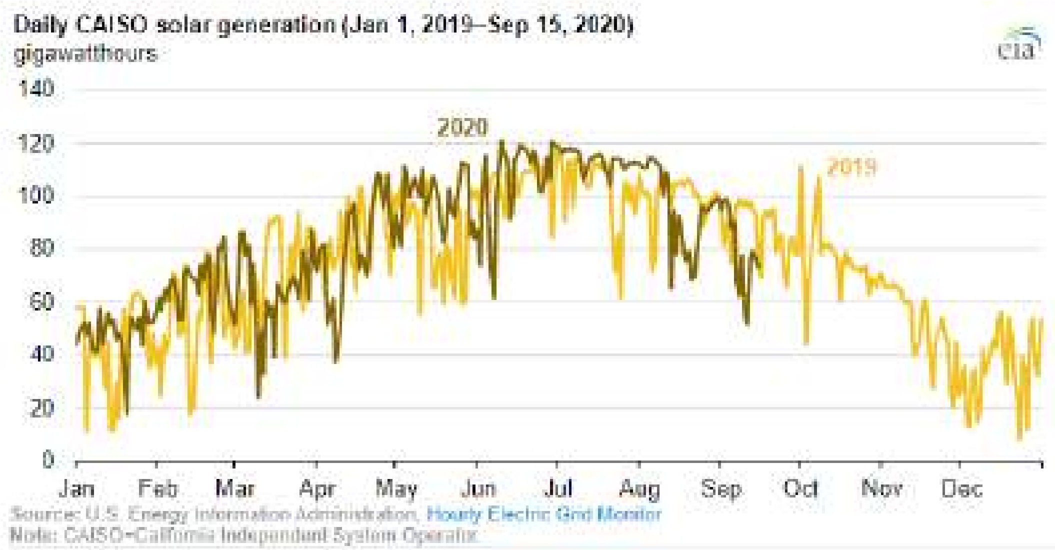
In the first two weeks of September 2020, average solar-powered electricity generation in the California Independent System Operator (CAISO), which covers 90% of utility-scale solar capacity in California, declined nearly 30% from the July 2020 average as wildfires burned across the state. Wildfire smoke contains small, airborne particulate matter particles that are generally 2.5 micrometers or smaller (referred to as PM2.5). This matter reduces the amount of sunlight that reaches solar panels, decreasing solar-powered electricity generation. As of September 28, California wildfires have burned an estimated 3.6 million acres in 2020, an area about the size of Connecticut.

According to data from the California Air Resources Board, peak California PM2.5 pollution began increasing in mid-August and reached a record high of 659 micrograms per cubic meter (µg/m3) on September 15, the highest level since record keeping began in 2000. Peak PM2.5 pollution is measured as the daily average value at the testing site that has the highest measured particulate matter concentration on a given day.

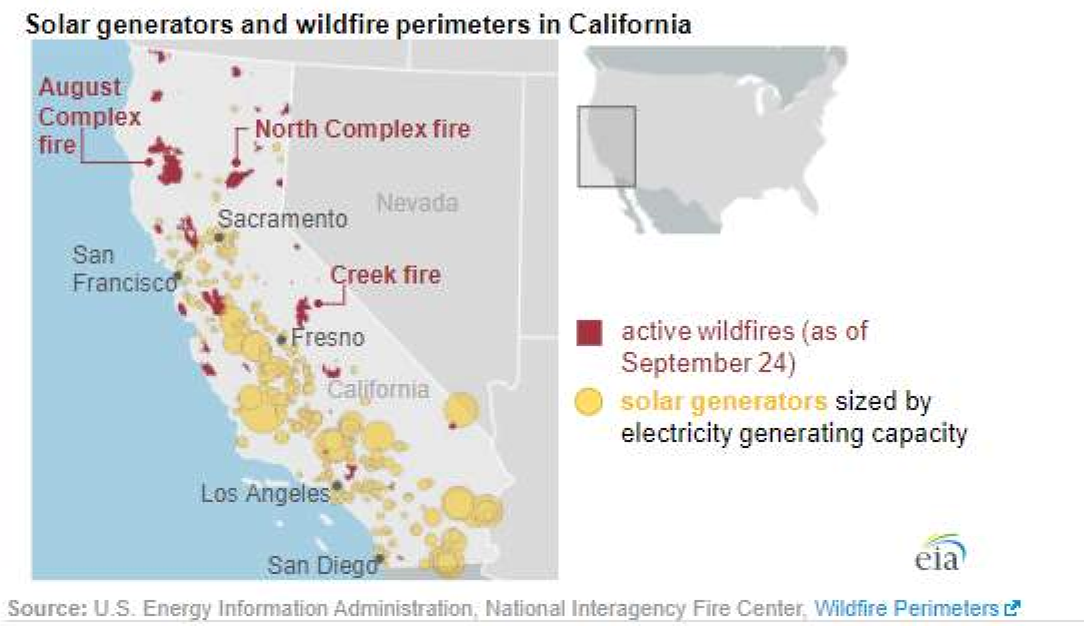


Source: U.S. Environmental Protection Agency, AirNow

In July 2020, daily solar-powered electricity generation, which includes generation from solar photovoltaic and solar thermal electric generators, ranged from 104 gigawatthours (GWh) to 119 GWh, averaging 113 GWh for the entire month. Daily solar-powered generation began declining as large wildfires broke out in mid-August, reaching a low of 68 GWh on August 22 before returning to approximately 100 GWh by the end of the month. Solar-powered generation began declining again as wildfire activity rose in September, falling as low as 50 GWh on September 11 as PM2.5 smoke pollution increased.



In the first two weeks of September 2020, solar-powered generation in CAISO was 13.4% lower than at the same time a year ago, despite growth in installed solar generating capacity in California. Since September 2019, California has added 659 megawatts (MW) of utility-scale solar-powered generation capacity, increasing total solar capacity by 5.3% to more than 13,000 MW as of June 2020. Although small-scale distributed solar photovoltaic capacity (such as rooftop solar panels) is not included in the Hourly Electric Grid Monitor solar generation data, small-scale solar accounts for a large share of total solar capacity in California. Small-scale solar capacity in California also increased in the past year, rising 11% to 9,800 MW.



Although most solar capacity in California is in the southern half of the state and the largest wildfires are currently concentrated in the northern and central parts of the state, offshore winds push wildfire smoke into Southern California. As of September 28, Cal Fire reports that the August Complex Fire, the largest wildfire in California history, was 45% contained. Other large, ongoing fires, such as the North Complex Fire and the Creek Fire, were 78% and 39% contained, respectively.

Principal contributor: Stephen York

Tags: generation, electricity, solar, California, states, map

Excerpt from
https://www.pge.com/en/about/newsroom/newsdetails/index.page?title=20210721_pge_announces_major_new_electric_infrastructure_safety_initiative_to_protect_communities_from_wildfire_threat_undergrounding_10000_miles_of_power_lines_in_highest_fire-threat_areas

PG&E Announces Major New Electric Infrastructure Safety Initiative to Protect Communities from Wildfire Threat; Undergrounding 10,000 Miles of Power Lines in Highest Fire-Threat Areas

Initiative Builds on Recent Successful Projects Using Undergrounding to Harden the Electric System and Mitigate Wildfire Risk

Release Date: July 21, 2021
Contact: PG&E External Communications (415) 973-5930
CHICO, Calif. — Pacific Gas and Electric Company (PG&E) today announced a major new initiative to expand the undergrounding of electric distribution power lines in High Fire Threat Districts (HFTD) to further harden its system and help prevent wildfires. The new infrastructure safety initiative, announced today in Butte County by PG&E Corporation CEO Patti Poppe, is a multi-year effort to underground approximately 10,000 miles of power lines. PG&E's commitment represents the largest effort in the U.S. to underground power lines as a wildfire risk reduction measure.

"We want what all of our customers want: a safe and resilient energy system. We have taken a stand that catastrophic wildfires shall stop. We will partner with the best and the brightest to bring that stand to life. We will demand excellence of ourselves. We will gladly partner with policymakers and state and local leaders to map a path we can all believe in," Poppe said.

In addition to significantly reducing wildfire risk, undergrounding also benefits customers by lessening the need for Public Safety Power Shutoffs, which are called as a last resort during dry, windy conditions to reduce the risk of vegetation contacting live power lines and sparking a wildfire. Undergrounding also eases the need for vegetation management efforts, leaving more of California's trees untouched.

Today, PG&E maintains more than 25,000 miles of overhead distribution power lines in the highest fire-threat areas (Tier 2, Tier 3 and Zone 1)—which is more than 30% of its total distribution overhead system.

10,000 miles of PG&E lines represents approximately the distance of 11 round trips from Chico to Los Angeles or almost half way around the world. The exact number of projects or miles undergrounded each year through PG&E's new expanded undergrounding program will evolve as PG&E performs further project scoping and inspections, estimating and engineering review.

Public Engagement with Stakeholders to Guide New Undergrounding Plan

PG&E will engage customers and stakeholders as it develops a plan and reviews potential additional undergrounding sites based on a variety of factors, including local municipal planning and safety considerations. Engineering an underground electric system requires designing the system around existing water, natural gas and drainage systems, as well as planning for future road widening. PG&E intends to work closely with customers and local, state, federal, tribal and regulatory officials throughout this new safety initiative.

Learning from Projects to Inform Expanded Undergrounding Effort

In the past, undergrounding has been done on a select, case-by-case basis, and largely for reasons other than wildfire risk reduction. Thanks to breakthroughs PG&E has achieved on undergrounding projects in recent years, undergrounding can now play a much more prominent role in PG&E's ongoing efforts to harden the electric grid. Following the devastating October 2017 Northern California wildfires and the 2018 Camp Fire, PG&E began to evaluate placing overhead power lines underground as a wildfire safety measure, and to better understand the construction and cost requirements associated with undergrounding for system hardening purposes. These demonstration projects were part of PG&E's Community Wildfire Safety Program (CWSP) and included the following:

- From 2018-2020, PG&E completed multiple demonstration projects aimed at converting overhead power lines to underground in high fire-threat areas of Alameda, Contra Costa, Nevada, and Sonoma counties.
- As a part of the rebuild efforts following the October 2017 Northern California wildfires, PG&E completed undergrounding eight miles of power lines in the Larkfield Estates and Mark West Estates communities in Sonoma County in 2018.
- In 2019, PG&E announced it would rebuild all its power lines underground in the Town of Paradise as it helps the community recover from the Camp Fire. The company is also rebuilding power lines underground within the 2020 North Complex Fire footprint in Butte County.

Through these demonstration projects and rebuild efforts, PG&E has been able to refine the construction and cost requirements associated with targeted undergrounding, enabling the acceleration and expansion of undergrounding projects. Learnings include:

- Implementing new planning systems and strategies and using new materials and new equipment to make undergrounding more cost effective.
- Building strong partnerships with material suppliers and contractors to accelerate undergrounding efforts.
- Partnering with natural gas projects as well as phone and internet providers to joint trench and share costs, where possible.
- Using new technology and construction methods to increase trench production.
- Bundling work into larger blocks to take advantage of economies of scale.
- Testing new cable and conduit materials to accelerate undergrounding work processes.

Ongoing PG&E Wildfire Mitigation and Resiliency Efforts
In addition to significantly expanding its undergrounding, PG&E's ongoing safety work to enhance grid resilience and address the growing threat of severe weather and wildfires continues on a risk-based and data-driven basis, as outlined in PG&E's 2021 Wildfire Mitigation Plan (WMP).
This includes:

- Installing stronger poles and covered power lines
- Deploying remote grids and community microgrids
- Targeted sectionalizing and grid reconfiguration
- Investing in centralized data analytics to reduce risk
- Conducting enhanced vegetation management
- Scaling the deployment of emerging technologies to proactively mitigate wildfire risk

Learn more about PG&E's wildfire safety efforts by visiting pge.com/wildfiresafety.
To watch a recording of today's announcement, visit PG&E's YouTube channel.

About PG&E
Pacific Gas and Electric Company, a subsidiary of PG&E Corporation (NYSE:PCG), is a combined natural gas and electric utility serving more than 16 million people across 70,000 square miles in Northern and Central California. For more information, visit pge.com and pge.com/news.

Top Indian Oil Refiner Betting on Robust Future for Fossil Fuels
2021-07-23 09:43:27.252 GMT

July 23 (National Post) -- (Bloomberg) - India's biggest oil refiner says fossil fuels will continue to be key part of the nation's energy mix as it embarks on a $13 billion expansion.
Indian Oil Corp. plans to increase its crude processing capacity by a third over the next five years to increase production of gasoline and diesel, along with petrochemicals, Chairman Shrikant Madhav Vaidya said in an interview. That will give the company the capability to refine 2.15 million barrels a day.
The big bet by Indian Oil will help meet an expected increase in the nation's energy consumption, although it contrasts with a notable shift from fossil fuels by some other key crude consumers. That includes local rival Reliance Industries Ltd. - operator of the world's biggest refining complex - which last year signaled a move toward cleaner alternatives from gasoline and diesel.
"I firmly believe all forms of fuel will have a place to stay - fossil fuels will be there," said Vaidya. "There's going to be demand for whatever we invest in. Consumption is going from leaps and bounds and energy security is the primary concern for me, which may not be the concern to the developed world."
The International Energy Agency predicted last year that India's oil use growth would surpass that of China in the mid-2020s and make it an attractive market for refinery investment. Russian oil producer Rosneft PJSC already has a foothold in the country after its purchase of refiner Essar Oil Ltd. - now known as Nayara Energy Ltd. - while Saudi Aramco is seeking to buy a stake in Reliance's oil-to-chemical business.
See also: The Retreat of Exxon and the Oil Majors Won't Stop Fossil Fuel
Indian Oil is taking some steps toward a greener future, however. The refiner is experimenting with the use of hydrogen for transport, it's blending more ethanol with gasoline, investing in battery technology and has plans to power all the new units at its refineries with renewable power.
"We are investing in solar and wind energy in a big way, we can use the grid to transmit that power to our plants," Vaidya said.

-0- Jul/23/2021 09:43 GMT

SAF Group created transcript of excerpts of Australia Deputy Prime Minister Barnaby Joyce's interview on ABC Insiders July 18, 2021 https://www.abc.net.au/insiders/sunday-july-18-full-program/13449960

Items in "*italics*" are SAF Group created transcript

At 27:20 min mark. ABC "*will you support any sort of Net Zero by 2050 emissions target*?". Joyce "*well this question is put up, just here beside me is the Walcha hotel and in the Walcha hotel they have a restaurant. Now, generally how restaurants work is you go in and get a menu and they have got what's on the menu for lunch and what the price is. Now that is how a competent decision is made and that's what we're looking for. What's on the menu and what the price is." what the labor party's approach is from what I see is they don't care".* ABC interrupts "*.. you're in government, your Deputy prime minister so what is your view?*" Joyce: "*Thank you very much and I want to thank the Australian people for that great honor. Our approach is we want to see exactly what's involved and we want to see exactly what the cost is. I think that is the rational process on how you go about anything and as I've said the Labor party's approach is they don't care what's on the menu and they don't care what is the price. and what turns up is sort of gherkins and sashimi tadpoles they're prepared to pay anything for it because they said they'll accept anything for lunch."*

Joyce: *"I can't be more clearer than that. what you're saying is you're saying give me an open check. do you want lunch? Well, I am quite happy to consider the menu when you tell me what's on it and what it costs"*

Joyce: *"We're gong to go round and round in circles on this. until you lay down a plan and show us the costs, you haven't arrived at a point of consideration. Show us a plan. Show us the costs and we're happy to consider it"*

ABC *"you said to Phil Curry in the Financial Review this week, the likelihood of Joyce getting endorsement from his own party room to agree to Net Zero is Zero, that's where the Net Zero lies".*"

Joyce: *"that is also a statement of the bleeding obvious. as leader of the party, you're not the sole person making unilateral decisions and the Nationals party room has a right to be part of that process and I'm intending to make sure they are".*

Joyce: *if I go to the party room, they'll say to me Barnaby what is the plan and what is the cost. And if I can't answer that question and we haven't got to that point yet, then of course its going to be a case where they say we have to be prudent and wait till we see, and when can you show us that process"* https://www.newswire.ca/fr/news-releases/le-gouvernement-du-quebec-n-autorise-pas-le-projet-de-liquefaction-de-gaz-naturel-energie-saguenay-804382264.html

Quebec government does not authorize Énergie Saguenay natural gas liquefaction project

NEWS PROVIDED BY **Office of the Minister of the Environment and the Fight against Climate Change**
Jul 21, 2021, 3:30 PM ET

SAGUENAY, QC, July 21 2021 / CNW Telbec / - In light of the environmental analysis report produced by the Ministry of the Environment and the Fight against Climate Change (MELCC), the government of Quebec has decided not to authorize the implementation of the Energy project Saguenay. This therefore puts an end to the project to build a natural gas liquefaction complex in Saguenay-Lac-Saint-Jean.

In a press conference held in Saguenay, the Minister of the Environment and the Fight against Climate Change, Minister responsible for the Fight against Racism and Minister responsible for the Laval region , Mr. Benoit Charette, indicated that the The initiator of the project, GNL Québec, was not able to demonstrate that it complied with the requirements set by the government to authorize the project, that is, positive effects in favor of the energy transition and the net reduction of global emissions greenhouse gases (GHGs).

As a result, and considering both the analyzes produced by his ministry and the important reservations and warnings issued by the Office of Public Hearings on the Environment (BAPE), the Minister recommended not to grant authorization environmental impact on the project.

Reasons for the refusal
Like the BAPE, whose conclusions were based, among other things, on the expertise of the International Energy Agency, the MELCC concludes that the implementation of a project like that of GNL Québec could have the long-term consequence of slowing down the energy transition of the client countries of the project.
MELCC experts are also of the opinion that the government could not count on a net reduction in GHG emissions on a global scale, since the initiator of the project cannot guarantee the use of liquefied natural gas as an alternative energy to sources that emit more GHGs, such as coal and fuel oil.
The MELCC also considers that the project initiator could not sufficiently guarantee that GHG reduction measures would actually be applied upstream for the exploitation and transport of gas or that it could adequately compensate its own. GHG emissions.

Quote:
“We had to face the facts that the risks of the Énergie Saguenay project outweigh its benefits. This is what explains the decision we made. However, we are optimistic that the Saguenay-Lac-Saint-Jean region will quickly have the opportunity to enrich itself with other economic projects, such as the Élysis green aluminum project, which will create jobs while actively participating in the fight of all of Quebec against climate change. "
Benoit Charette , Minister of the Environment and the Fight Against Climate Change, Minister responsible for the Fight against Racism and Minister responsible for the Laval region

“As Minister responsible for the Saguenay-Lac-Saint-Jean region, and as a citizen of here, it is certain that this project initially brought hope for the economy of our beautiful region. However, the circumstances being what they are, this project will not see the light of day. My message today is that our government will continue to work hard to attract investors to Saguenay-Lac-Saint-Jean and to create quality jobs. The region retains all its potential and we must continue to be welcoming! " *Andrée Laforest, Minister responsible for the Saguenay-Lac-Saint-Jean region and Member of Parliament for Chicoutimi*

Highlights:

- The Énergie Saguenay project aimed to liquefy natural gas in order to export it to world markets. It was subject to the environmental impact assessment and review procedure provided for in the Environment Quality Act. As part of this procedure, the project was the subject of a public hearing held by the BAPE from September 14, 2020 to March 10, 2021, a consultation with the Innu communities of Mashteuiatsch and Essipit, then a analysis on environmental acceptability carried out by the MELCC, with the collaboration of numerous experts from the government apparatus.
- The environmental analysis report produced by the MELCC does not make it possible to conclude on the environmental acceptability of the project with regard, in particular, to the global GHG balance, the energy transition and the cost-benefit balance of the project.

Related links:
To read the BAPE file on the project:
https://www.bape.gouv.qc.ca/fr/dossiers/projet-construction-complexe-liquefaction-gaz-naturel-saguenay .
To consult the environmental assessment file on the project:
https://www.ree.environnement.gouv.qc.ca/projet.asp?no_dossier=3211-10-021
SOURCE Office of the Minister of the Environment and the Fight against Climate Change

For further information: Source: Rosalie Tremblay-Cloutier, Press Secretary, Office of the Minister of the Environment and the Fight against Climate Change, 438 777-3777; Information: Media relations, Ministry of the Environment and the Fight against Climate Change, 418 521-3991
Related links
http://www.environnement.gouv.qc.ca/

Bloomberg @TheTerminal: Canada Greenhouse Gas Emission Cut Bill Becomes Law (1)
2021-06-30 14:39:47.859 GMT

By James Munson
(Bloomberg Law) -- Canada will have to set national greenhouse gas emission reduction targets every five years, under legislation adopted into law.
The bill, known as the Canadian Net-Zero Emissions Accountability Act, passed the Senate, Canada's upper house, without amendment after clearing the House of Commons June 22. It's received Royal Assent, a formal procedure that makes the bill law.
The legislation requires Ottawa to lay out plans for how it will meet reduction targets that begin in 2030 and end in 2050, when the goal is net-zero emissions, according to the legislation. Regulators also must issue progress reports.
The bill is meant to strengthen the transparency and accountability of Canada's plans to reduce greenhouse gas emissions after decades of missing targets set at international climate change conferences.

Reduction Targets

Prime Minister Justin Trudeau during President Joe Biden's summit on climate change April 22 unveiled a reduction target of 40% to 45% below 2005 emission levels by 2030.
The Environment and Climate Change Canada minister must release the targets and plans for how to reach them at least five years before each target year, according to the legislation. The minister must provide a progress report two years before the target year and an assessment report one year later, it says.
The legislation also creates a 15-person advisory body to inform the target plans.
The House of Commons amended the bill to include 2023, 2025 and 2027 progress reports over concerns from left-leaning opposition parties that the targets were too far off in the future to increase accountability.
The Standing Committee on Environment and Sustainable Development also amended the bill to require the environment minister to include a 2026 interim reduction target within the plan to reach the 2030 target.
The committee also added mandatory factors the advisory body must include in its reports to the minister and made it compulsory for the minister to publish their response to the body's recommendations.
To contact the reporter on this story: James Munson in Ottawa at jmunson@bloombergindustry.com
To contact the editor responsible for this story: John Hughes at jhughes@bloombergindustry.com

https://www.shell.com/media/news-and-media-releases/2021/20-july-press-release.html

Shell confirms decision to appeal court ruling in Netherlands climate case

Jul 20, 2021

Royal Dutch Shell plc (Shell) today confirmed that it will appeal a ruling issued by the District Court in The Hague, in May 2021, that Shell must reduce its global net carbon emissions by 45% by 2030 compared to 2019 levels.

Shell wants to rise to the challenge of the ruling and accelerate its Powering Progress strategy to become a net-zero emissions energy business by 2050, in step with society's progress towards the goal of the Paris Agreement on climate change. As part of this strategy, Shell had already set its own short- and medium-term targets for cutting carbon emissions. It is working with customers, governments and wider society, sector by sector, to establish rapid and realistic ways to get to net zero.

"We agree urgent action is needed and we will accelerate our transition to net zero," said Royal Dutch Shell Chief Executive, Ben van Beurden. "But we will appeal because a court judgment, against a single company, is not effective. What is needed is clear, ambitious policies that will drive fundamental change across the whole energy system. Climate change is a challenge that requires both urgent action and an approach that is global, collaborative and encourages coordination between all parties."

Shell published details of its Powering Progress strategy in April 2021. The court did not consider this because the hearings that led to the ruling took place several months earlier. In May 2021, Shell became the first energy company to put its energy transition strategy to a vote of shareholders at its Annual General Meeting. It secured 89% support. Shell will continue to give investors an annual vote on its progress in delivering on its strategy.

Shell has set out its intention to reduce both the emissions from its own operations, referred to as Scopes 1 and 2, and those produced when customers use the energy products it sells. These Scope 3 emissions account for over 90% of Shell's emissions, so Shell is working with its customers to achieve this reduction.

Shell has already set out a number of actions to reduce Scope 1 and 2 emissions through a combination of energy efficiency improvements, the elimination of routine flaring, carbon capture and storage technology, working with suppliers to use renewable electricity in facilities and concentrating its global refining portfolio from 13 Shell-controlled sites in 2019 into five Energy and Chemicals parks by 2030. Shell is working on a plan to scale-up and accelerate these efforts within its Powering Progress strategy.

Notes to editors

- On Wednesday May 26, 2021, the District Court in The Hague delivered its ruling in the climate change case filed against Royal Dutch Shell plc ("Shell") by Milieudefensie (Friends of the Earth Netherlands), other NGOs and a group of private individuals. The court ruled that Shell must reduce the CO2 emissions of Shell group operations and energy-carrying products sold by 45% (net) by the end of 2030 compared to its emissions in 2019. See **updated FAQ**.
- Shell's Powering Progress strategy includes targets to become a net-zero emissions energy business by 2050, in step with society's progress towards achieving the Paris Agreement goal of limiting the increase in the average global temperature to 1.5°C. To find out more, visit **www.shell.com/powering-progress**
- To read Shell's Energy Transition Strategy document, which was submitted for a shareholder vote, visit **www.shell.com/energytransitionstrategy**.
- Shell expects that total carbon emissions for the company peaked in 2018. For more information on Shell's emissions visit **www.shell.com/emissionsexplainer**.
- Shell's oil production peaked in 2019 and it expects that oil production will decline gradually by 1-2% a year, including divestments, until 2030.

https://www.wsj.com/articles/gm-recalls-chevy-bolts-for-second-time-due-to-fire-risk-11627045849?mod=hp_lead_pos2

GM Recalls All-Electric Chevy Bolt for Second Time Due to Fire Risk

The company is advising owners of 2017-19 model year vehicles to keep their charges at a certain level and to park them outside after charging

GM says its investigation into recent battery fires involving the Chevy Bolt found that manufacturing defects in a certain battery cell were the root cause

PHOTO: JOHN MARSHALL MANTEL/ZUMA PRESS

By

Mike Colias

Updated July 23, 2021 11:26 am ET

General Motors Co. GM -0.34% is recalling its all-electric Chevrolet Bolt for a second time because of a potential battery defect that can cause a fire, underscoring the technical challenges car companies face as they race to develop more plug-in vehicles.

GM said Friday that its investigation into recent battery fires involving the cars found that manufacturing defects in a certain battery cell were the root cause. It is asking owners of

2017-2019 model year Bolts to keep their electric-vehicle charges at a certain level and to park the cars outside after charging them.

Under the previous recall, initiated in November, owners of 69,000 Bolts were advised to get a software update that would monitor the condition of the lithium-ion battery and flag any potential problems.

GM has since learned that at least one battery fire occurred in a vehicle that had received the software update, the company spokesman said. The company is aware of eight fires total and two related injuries but no deaths, he said.

“Unfortunately the software update was not fully effective in addressing the safety risk in the vehicle, hence the second recall,” the spokesman said.

The remedy will include some changes to the battery hardware but a final solution hasn’t yet been determined, he said.

The problems come as major auto makers deepen their investment in electric vehicles with plans to release dozens of new plug-in models in the coming years, a shift being driven by tighten tailpipe-emissions regulations. GM is placing one of the auto industry’s biggest bets on the technology with plans to spend $35 billion by 2025 on 30 new electric models.

Electric vehicles still account for a small percentage of the overall car market, but their sales are picking up in the U.S. and globally, as new options become available in showrooms and auto executives push to highlight the benefits of the technology. In the first half of 2021, sales of plug-in electric vehicles in the U.S. more than doubled over the prior-year period, far outpacing the broader auto industry’s growth.

Still, challenges remain for auto manufacturers trying to convince buyers to make the switch, including higher sticker prices, range anxiety and a lack of charging stations. Concerns about battery fires have also weighed on the auto industry, although researchers have said the risks of a blaze in an electric vehicle are comparable to gas-powered cars and incidents are relatively rare.

The lithium-ion batteries in electric cars are similar to those found in consumer electronics and are designed to store large amounts of energy relative to their size. To power an automobile, car companies use more of them, and the energy demands are higher, creating a unique hazard.

Other car companies also have had trouble in the past year with fires involving lithium-ion batteries used in electric vehicles. Ford Motor Co. , Hyundai Motor Co. and BMW AG each issued recalls for new battery-powered models last year.
The Bolt until recently was GM's only electric vehicle on sale in the U.S. It recently began selling a larger version of the Bolt and later this year is scheduled to release a Hummer electric pickup truck under its GMC brand.
Meanwhile, owners are being told to charge their cars to 90% capacity and not to drive them below 70 miles of range. They also should park their car outside immediately after charging and not charge them overnight, the company said.

The auto maker said notified customers last week that it was investigating the cause of two battery fires.
LG Energy Solution, a unit of Korea's LG Group, supplies the battery cells for the Bolt. A LG representative didn't immediately respond to a request for comment.
The Hummer and other plug-in models in the works for GM brands will use a new electric-vehicle system that was developed by the Detroit auto maker and includes an updated battery chemistry, the company has said.

GM is moving to produce its own batteries through a joint venture with LG. The two companies are building a battery factory in Ohio and GM has said it plans three more U.S. battery plants. Their collaboration reflects a broader push by car companies to secure future battery supplies as competition for the parts and materials intensifies.
Write to Mike Colias at Mike.Colias@wsj.com

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

Consumer Alert: Important Chevrolet Bolt Recall for Fire Risk

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.

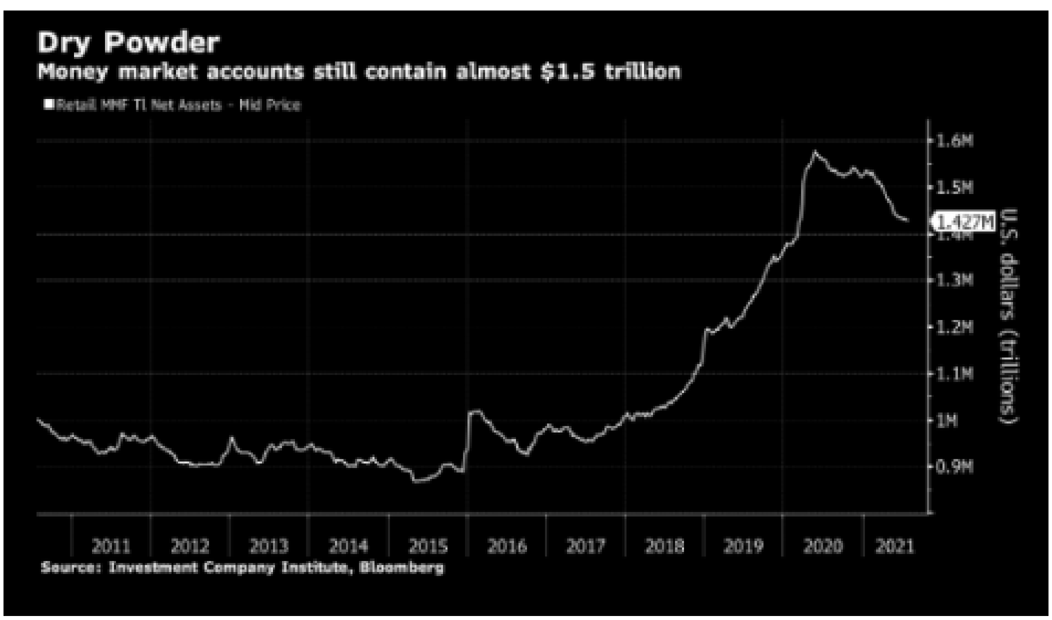
NHTSA opened an investigation (PE 20-016) in October 2020, continues to evaluate the information received, and is looking into these latest fires.

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.

Stock Bulls Look Toward $17 Trillion Burning a Hole in Pockets
2021-07-24 16:27:52.180 GMT

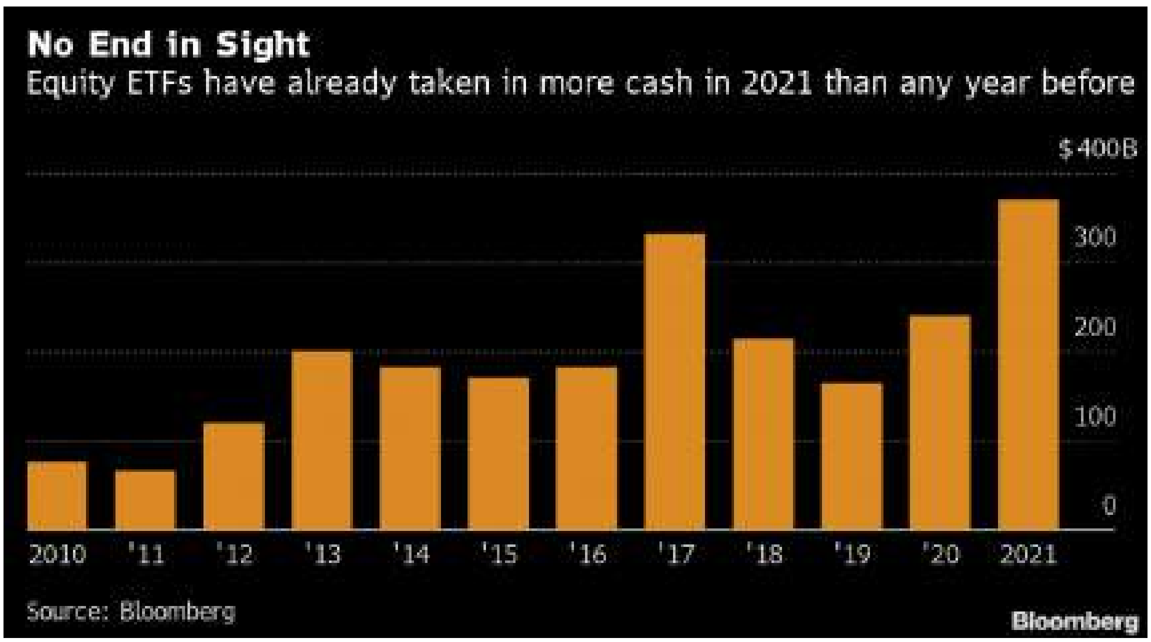
By Claire Ballentine
(Bloomberg) -- In the stock market, the refusal of retail investors to back down from every macro threat has become the only story. When will it end? Judging by the size of all the pools of cash lying around, it could be a while.
Among all the economic stories of the pandemic, the one about money piling up in people's accounts has been the most significant in the stock market, where the S&P 500 just notched its seventh gain in nine weeks. Money market accounts, viewed in some circles as a "dry powder" reserve for equity deployment, sit at just under $4.5 trillion. A more obscure balance, the Federal Reserve's count of money on deposit with commercial banks, has risen 33% from 2019 to $17 trillion.
While none of the money is completely unencumbered and professionals tend to hate the concept of "cash on the sidelines," something is arming the day-trader cadres who seem bent on letting no market selloff last more than 24 hours. Take Monday, for example, when fears the delta variant would upend progress sent the S&P 500 down as much as 2.2%. Dip buyers ran to the rescue then and the rest of the week, sending the S&P 500 higher by almost 2% through Friday, despite virus cases still spiking.
"We have investors who are eager to deploy cash," said Sara Rajo-Miller, investment advisor at Miracle Mile Advisors. "People sometimes forget how much power retail investors can have over the market, and we've seen that play out clearly. That momentum can really push stocks higher."



How powerful is the retail cannon? On Monday alone, they bought a record $2.2 billion worth of equities, with the biggest exchange-traded fund tracking the S&P 500, ticker SPY, alone notching an all-time high of $482 million in retail purchases, according to Vanda Research. An analysis from DataTrek Research showed that Google searches in the U.S. that day for the phrase "dow jones" -- the term most associated with stock market investing, according to the firm -- spiked when stocks declined quickly, peaking at 1 p.m. in New York.

"It's almost like investors are seasoned to say, stocks are down, it's got to be a buying opportunity," said Gene Goldman, chief investment officer at Cetera Financial Group. "Part of that is because there's no other game in town right now. You look at bond yields so low, cryptocurrencies struggling, other parts of the market are not that great."

The unending appetite for stocks led equity ETFs to break their annual record in April, and the pace hasn't slowed since. In July, the products have already taken in more than $15 billion, helping fuel total ETF inflows to the brink of a full-year record, with more than five months to go.



Still, other measures of retail prowess show a mixed picture. Data from Charles Schwab shows that the percentage of cash in their clients' brokerages accounts in June fell to 10.5%, the lowest since 2018.

"That probably suggests that the dry powder has been put to work over the course of the year, but maybe it's not entirely out of fuel for further investment," said Jeffrey Kleintop, chief global investment strategist for Charles Schwab & Co. "There's still a good bit of momentum and desire to put money to work and look for alternatives to the bond market which remains relatively unattractive."

Retail money fund balances still have $1 trillion versus $643 billion in 2015, according to DataTrek, with analysts calculating that there's $400 billion in "buy the dip" cash ready for the next drawdown. Plus, retail-favorite Robinhood has 13 million more funded accounts than it did before the pandemic.

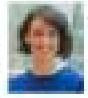
“The buy-the-dip mentality is the one the Fed has taught institutional and retail investors to follow, and the Fed remains hyper easy,” said Jim Smigiel, chief investment officer of SEI. “The biggest positive out there is that the easy stance from the Fed is in place and every other central bank and is going to be in place for quite some time.”

To contact the reporter on this story:
Claire Ballentine in New York at cballentine@bloomberg.net
To contact the editors responsible for this story:
Jeremy Herron at jherron8@bloomberg.net
Michael P. Regan

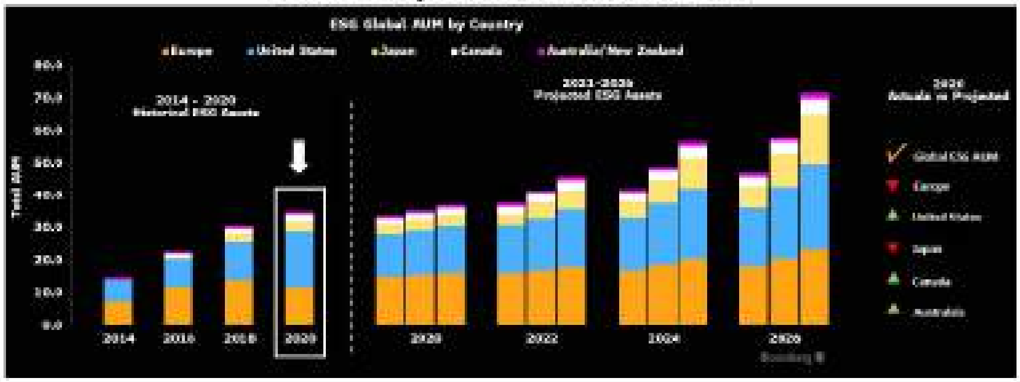
To view this story in Bloomberg click here:
https://blinks.bloomberg.com/news/stories/QWPUA1DWLU68

Excerpt from Bloomberg Intelligence: Midyear Outlook: ESG Assets Under Management


Adeline Diab
Team: ESG
BI Head of ESG and Thematic Investing EMEA

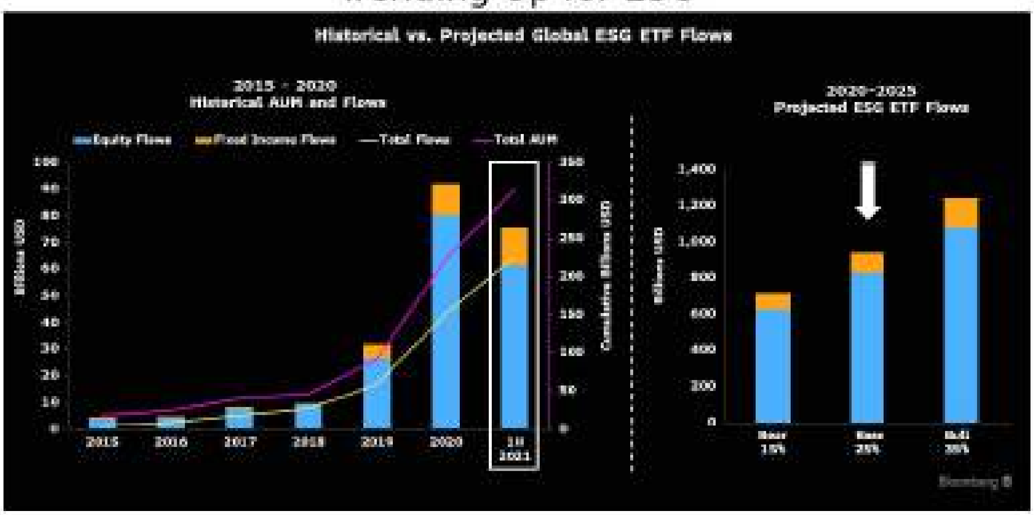

Gina Martin Adams
Team: Strategy
BI Chief Equity Strategist

ESG Projected Global AUM



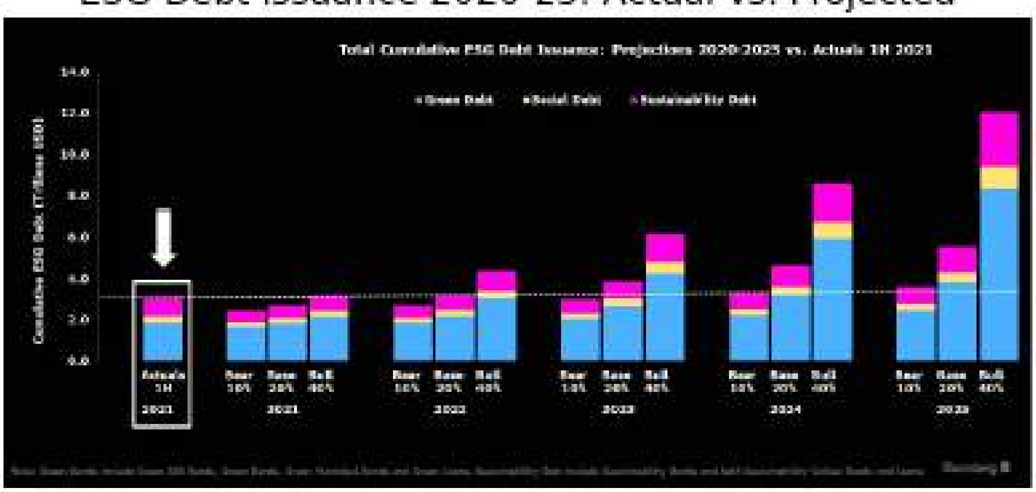
Source: Bloomberg Intelligence

Trending Up for ESG



Source: Bloomberg Intelligence

ESG Debt Issuance 2020-25: Actual vs. Projected



Source: Bloomberg Intelligence

THE INVESTMENT FUNDS INSTITUTE OF CANADA | L'INSTITUT DES FONDS D'INVESTISSEMENT DU CANADA

IFIC Monthly Investment Fund Statistics – June 2021

Mutual Fund and Exchange-Traded Fund Assets and Sales

July 21, 2021 (Toronto) – The Investment Funds Institute of Canada (IFIC) today announced investment fund net sales and net assets for June 2021.

Mutual fund assets totalled $1.950 trillion at the end of June 2021. Assets increased by $53.3 billion or 2.8% compared to May 2021. Mutual funds recorded net sales of $12.6 billion in June 2021.

ETF assets totalled $306.8 billion at the end of June 2021. Assets increased by $9.4 billion or 3.2% compared to May 2021. ETFs recorded net sales of $5.0 billion in June 2021.

Mutual Fund Net Sales/Net Redemptions ($ Millions)*

Asset Class	Jun. 2021	May 2021	Jun. 2020	YTD 2021	YTD 2020
Long-term Funds					
Balanced	8,053	4,243	550	39,575	(6,652)
Equity	3,796	3,266	245	25,925	1,918
Bond	1,112	1,093	3,054	9,330	4,692
Specialty	565	345	462	3,099	2,898
Total Long-term Funds	13,526	8,948	4,311	77,929	2,856
Total Money Market Funds	(942)	(561)	(429)	(6,002)	4,965
Total	12,584	8,386	3,882	71,927	7,821

Mutual Fund Net Assets ($ Billions)*

Asset Class	Jun. 2021	May 2021	Jun. 2020	Dec. 2020
Long-term Funds				
Balanced	959.1	933.4	798.6	874.4
Equity	686.9	662.1	507.9	593.4
Bond	257.2	254.3	227.4	246.4
Specialty	18.7	18.0	29.0	35.0
Total Long-term Funds	1,921.9	1,867.8	1,562.9	1,749.3
Total Money Market Funds	27.8	28.5	37.0	34.4
Total	1,949.7	1,896.3	1,599.8	1,783.7

* Please see below for important information regarding this data.

ETF Net Sales/Net Redemptions ($ Millions)*

Asset Class	Jun. 2021	May 2021	Jun. 2020	YTD 2021	YTD 2020
Long-term Funds					
Balanced	320	284	131	2,328	962
Equity	2,727	3,797	2,657	18,087	15,425
Bond	1,224	1,751	1,054	8,023	3,472
Specialty	665	1,941	98	5,785	999
Total Long-term Funds	4,936	7,773	3,941	34,223	20,859
Total Money Market Funds	103	(177)	180	(1,573)	1,770
Total	5,039	7,596	4,121	32,650	22,629

ETF Net Assets ($ Billions)*

Asset Class	Jun. 2021	May 2021	Jun. 2020	Dec. 2020
Long-term Funds				
Balanced	10.1	9.7	5.6	7.2
Equity	195.4	188.6	131.6	158.4
Bond	85.8	84.1	70.1	79.3
Specialty	9.8	9.5	4.3	5.2
Total Long-term Funds	301.2	291.9	211.6	250.0
Total Money Market Funds	5.7	5.6	6.2	7.3
Total	306.8	297.4	217.8	257.3

* Please see below for important information regarding this data.

IFIC direct survey data (which accounts for approximately 91% of total mutual fund industry assets) is complemented by data from Investor Economics to provide comprehensive industry totals.

IFIC makes every effort to verify the accuracy, currency and completeness of the information; however, IFIC does not guarantee, warrant, represent or undertake that the information provided is correct, accurate or current.

*** Important Information Regarding Investment Fund Data:**

1. Mutual fund data is adjusted to remove double counting arising from mutual funds that invest in other mutual funds.
2. ETF data is not adjusted to remove double counting arising from ETFs that invest in other ETFs.
3. The Balanced Funds category includes funds that invest directly in a mix of stocks and bonds or obtain exposure through investing in other funds.
4. Mutual fund data reflects the investment activity of Canadian retail investors.
5. ETF data reflects the investment activity of Canadian retail and institutional investors.

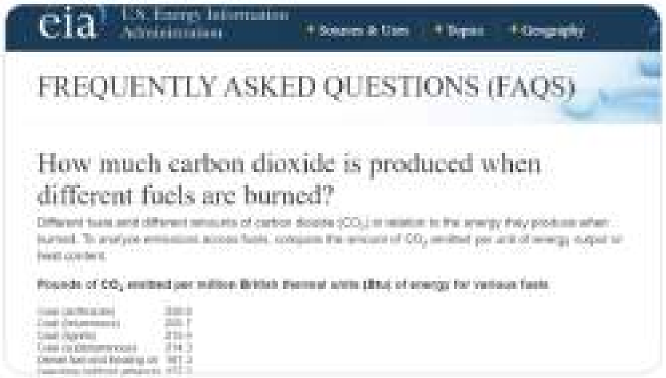
About IFIC
The Investment Funds Institute of Canada is the voice of Canada's investment funds industry. IFIC brings together 150 organizations, including fund managers, distributors and industry service organizations, to foster a strong, stable investment sector where investors can realize their financial goals. By connecting Canada's savers to Canada's economy, our industry contributes significantly to Canadian economic growth and job creation. To learn more about IFIC, please visit www.ific.ca.

For more information please contact:

Pira Kumarasamy
Senior Manager, Communications and Public Affairs

Dan Tsubouchi @Energy_Tidbits · 3h

Japan to use #Ammonia to replace 20% of fuel at 7 #Coal power plants. How does this fit in push to reduce emissions as coal is 2x #NatGas emissions? Hmmm! Or is it Japan practical approach & worried about mid/long term relative #LNG vs coal prices/supply? Thx @SStapczynski


eia U.S. Energy Information Administration

FREQUENTLY ASKED QUESTIONS (FAQS)

How much carbon dioxide is produced when different fuels are burned?

Different fuels emit different amounts of carbon dioxide (CO_2) in relation to the energy they produce when burned. To analyze emissions across fuels, compare the amount of CO_2 emitted per unit of energy output or heat content.

Pounds of CO_2 emitted per million British thermal units (Btu) of energy for various fuels

> **Stephen Stapczynski** @SStapczynski · 6h
>
> Japan plans for ammonia and hydrogen to make up 1% of its 2030 power mix
>
> How will they achieve that? Mix it with fuel at coal power plants
>
> ...
>
> Show this thread

1 1 2

Dan Tsubouchi @Energy_Tidbits · 13h

first #Canmore wild raspberries picking this summer from the raspberry bushes on the hill beside our place. about the size of a pea.

13

SAF

Dan Tsubouchi @Energy_Tidbits · Jul 24

IOC Chair why 1/3 increase to India #Gasoline #Diesel output "consumption is going from leaps and bounds and energy security is primary concern for me, which may not be the concern to the developed world". Why @POTUS @JustinTrudeau will ask #G7 to pay more than fair share #OOTT

"I firmly believe all forms of fuel will have a place to stay - fossil fuels will be there," said Vaidya. "There's going to be demand for whatever we invest in. Consumption is going from leaps and bounds and energy security is the primary concern for me, which may not be the concern to the developed world."

The International Energy Agency predicted last year that India's oil use growth would surpass that of China in the mid-2020s and make it an attractive market for refinery investment. Russian oil producer Rosneft PJSC already has a foothold in the country after its purchase of refiner Essar Oil Ltd. - now known as Nayara Energy Ltd. - while Saudi Aramco is seeking to buy a stake in Reliance's oil-to-chemical business.

See also: The Retreat of Exxon and the Oil Majors Won't Stop Fossil Fuel

1 2

SAF

Dan Tsubouchi @Energy_Tidbits · Jul 23

Note $PD why broad group of Cdn public E&P are able to increase drilling while being highly capital disciplined. Fits SAF Group view Cdn E&P long established total return models only got stronger with high prices. Big advantage to Cdn public E&P vs US E&P #OOTT

Excerpts Precision Drilling Q2 Call July 22, 2021, Courtesy of Bloomberg @TheTerminal Transcripts

"Looking closer at our Canadian customer mix, while private equity producers play an important role over 2/3 of the demand we see comes from publicly listed producers. This group has seen has experienced several years of operating within capital constrained in fiscally disciplined framework.

They've been focused on debt reduction and return of capital to shareholders. Since the middle of the last decade and driven cost efficiencies through all aspects of their business models. Additionally, we've seen several key consolidating transactions. Our customer space that further buildup up scale and efficiency.

And now with the improving commodity fundamentals. The firm AECO gas and Western Canada Select oil prices and resilient NGL pricing. They have responded to quickly but modestly, increasing drilling activity, while remaining highly capital disciplined. This modest increase in spending has a meaningful impact when multiplied across the full producers producer space.

I'm confident we'll see a similar trend emerge in the US as public producers as the public producers older producer hedges roll off at a replaced with the current strip and these customers find a path to balanced modest growth with sustained shareholder returns."

"So in summary, our Canadian business is will not require significant capital spending,

Dan Tsubouchi @Energy_Tidbits · Jul 22

Outlook for overall Cdn #Oil #NatGas market over the next 12 months "remains exceptionally bright" says $PD in Q2 release. Look at rigs outlook, not just #Montney. Cdn E&P long established total return (income + growth) models only got stronger with high prices ...

2 9

SAF

Dan Tsubouchi @Energy_Tidbits · Jul 23

not the usual elk, deer or coyote wildlife in #Canmore that catches my eye while looking at my screen. wonder if this little guy is doing advance scouting for a winter food stash location.

2

SAF

Dan Tsubouchi @Energy_Tidbits · Jul 23

#TeamCanada so excited for our 370 cdn men and women athletes, who are now olympians. they must be pumped and ready to go. compete and enjoy what will be the experience of a lifetime. Go TramCanada

4

SAF

Dan Tsubouchi @Energy_Tidbits · Jul 23

cool tidbit from opening ceremony that athletes at 64 olympics planted seeds and some of the resultant trees are used in @Tokyo2020 opening ceremonies. i assume in the wood for the rings. athletes planting seeds again

1 2

SAF

Dan Tsubouchi @Energy_Tidbits · Jul 23

#Schlumberger Q2 just out. Strong international #Oil #NatGas momentum to continue as cyclical recovery to unfolds, but anticipate US/CAN growth rate to moderate unless upside to private E&P spending. $SLB Q2 call at 9:30am ET. #OOTT

slb.com/newsroom/press...

3

SAF

Dan Tsubouchi @Energy_Tidbits · Jul 23

#LNGSupplyGap. Distant hope of peace in Mozambique, #TotalEnergies source tells @EMRumney @DG_Lewis ""I don't see a short-term solution ... The government has failed so many times." See SAF Group Apr 28 blog safgroup.ca/insights/trend...

reuters.com/article/mozamb...

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?

1 2

SAF

Dan Tsubouchi @Energy_Tidbits · Jul 22

Great #NatGas prices with #HenryHub ~3.95 & #AECO ~$3.70. Don't forget #SabinePassLNG Train 6 & #CalcasieuPassLNG add another ~2 bcf/d of US natural gas that will have #LNG export option.

> **Dan Tsubouchi** @Energy_Tidbits · Jul 19
>
> Even if US #NatGas storage is close to 3 tcf on Oct 31, 2022, that is ~700 bcf less than normal. It makes 2023 #HenryHub strip of $2.81 & 2023 #AECO strip of C$2.55 look pretty cheap. Thx @BloombergNEF Nakul Nair for highlighting #SabinePassLNG Train 6 & #CalcasieuPassLNG twitter.com/Energy_Tidbits...

2 2

SAF

Dan Tsubouchi @Energy_Tidbits · Jul 22

first #Gasoline fill up in a couple weeks in #Calgary. 91 octane now 159.9/litre at Husky station

1 · 4

SAF

Dan Tsubouchi @Energy_Tidbits · Jul 22

#SaudiEnergyMinister Abdulaziz is the top of my list of 3 people to invite to dinner. <2 yrs on job, Abqaiq missile attack, Covid, global recession yet he saved #Oil markets. He is "The Man" and the master of the impossible - herding #OPEC+ cats. Great @JavierBlas story. #OOTT

> **Javier Blas** @JavierBlas · Jul 22
> LONG READ: My profile of Prince Abdulaziz bin Salman, the most powerful man in petroleum. The Saudi oil minister navigates unruly OPEC+ nations, huge swings in prices — and the end of fossil fuels | #OOTT #SaudiArabia bloomberg.com/news/features/...

1 · 6

SAF

Dan Tsubouchi @Energy_Tidbits · Jul 22

Outlook for overall Cdn #Oil #NatGas market over the next 12 months "remains exceptionally bright" says $PD in Q2 release. Look at rigs outlook, not just #Montney. Cdn E&P long established total return (income + growth) models only got stronger with high prices #OOTT

1 · 7 · 17

Dan Tsubouchi @Energy_Tidbits · Jul 21

QC rejects #SaguenayLNG as can't demonstrate positive effects in favor of the energy transition & the net reduction of global GHG. Negative to Cdn #Oil #NatGas as likely previews #Trudeau #Liberals decisions, its now The Law to stay on track to #NetZero emissions target. #OOTT

Dan Tsubouchi @Energy_Tidbits · Jul 4

1/3. ICYMI, Negative to Cdn #Oil & #NatGas. #Trudeau can say he has to accelerate actions because its now the law, he has to keep CAN on track to meet 2025 & 2030 emissions targets. See SAF June 4, 2021 Energy Tidbits. Thx @james_munson #OOTT ...

Show this thread

1 3 3

Dan Tsubouchi @Energy_Tidbits · Jul 21

For those not near their laptop, @EIAgov weekly #Oil #Gasoline #Distillates inventory data as of July 16 just out. Prior to release, WTI was $69.38. #OOTT

ir.eia.gov/wpsr/overview....

Oil/Products Inventory July 16: EIA, Bloomberg Survey Expectations, API

(million barrels)	EIA	Expectations	API
Oil	2.11	-4.50	0.81
Gasoline	-0.12	-1.05	3.31
Distillates	-1.35	-0.65	-1.23
	0.64	-6.20	2.89

Note: In addition, there was no change in the SPR for July 16 week
Note: Cushing had a draw of 1.36 mmb for July 16 week
Source EIA, Bloomberg
Prepared by SAF Group

1

Dan Tsubouchi @Energy_Tidbits · Jul 21

Overlooked factor in most long term #Oil demand forecasts & why demand should increase in 2020s - global road transport fleet is growing. Note how fleet expansion impacts @BloombergNEF @DavidDo26949144 forecast for road fuels 43.8 mmbd in 2019 dropping to 25.3 mmbd in 2050 #OOTT

Change in road fuel demand, 2019-2050

To contact the reporter on this story:

To contact the editor responsible for this story:

6

Dan Tsubouchi @Energy_Tidbits · Jul 21

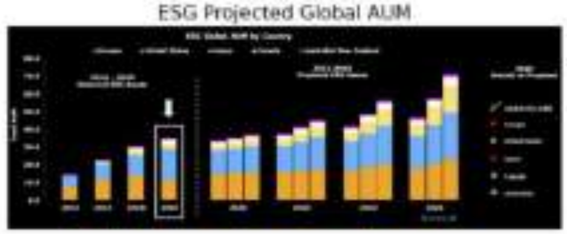
No question, capital is going to ESG. Great #ESG AUM recap/outlook. ESG AUM >$35T, fcast >$50T by 2025 & 1/3 of global AUM. US ESG AUM 40% growth to $17T. ESG debt starting to pick up, now $3T fcast $11T by 2025. Thx @Bloomberg @diabline @GinaMartinAdams

Excerpt from Bloomberg Intelligence: Midyear Outlook: ESG Assets Under Management

Adeline Diab
Team: ESG
BI Head of ESG and Thematic Investing EMEA

Gina Martin Adams
Team: Strategy
BI Chief Equity Strategist

ESG Projected Global AUM



Dan Tsubouchi @Energy_Tidbits · Jul 21

"we expect spending and activity levels to gain momentum through the year as the macro environment improves, likely setting up the industry for stronger growth in 2022." Baker Hughes Q2 release, Q2 call about to start. #OOTT #natgas

Baker Hughes Company Announces Second Quart...
The Investor Relations website contains information about Baker Hughes's business for stockholders, ...
investors.bakerhughes.com

1 1 3

Dan Tsubouchi @Energy_Tidbits · Jul 21

Great thread to read. Negative to #LNG for 2020s. Japan new 2030 target for power generation sees big cut to electricity from LNG #NatGas. To 2030, share of power generation, #Renewable +18-20%, LNG -17%, #Coal -13%. #Nuclear +14-16% will be key for 24/7 power. Thx SStapczynski

> **Stephen Stapczynski** @SStapczynski · Jul 21
>
> BREAKING: Japan revises its 2030 power mix targets, cutting fossil fuels and raising renewables in a bid to reduce pollution
>
> The biggest loser? LNG
>
> Under the draft plan, annual LNG power generation is slated to fall roughly 50% by the end of the decade. That's more than coal
>
> Show this thread

Energy	FY2030 (Revised)	FY2030 (Previous)	FY2019
Renewables	36%-38%	22%-24%	18%
LNG	20%	27%	37%
Coal	19%	26%	32%
Oil	2%	3%	7%
Nuclear	20%-22%	20%-22%	6%
Hydrogen/Ammonia	1%	0%	0%

1 1 2

Dan Tsubouchi @Energy_Tidbits · Jul 20

#PipeDream for AU Deputy PM @Barnaby_Joyce wants rational process for #NetZero approval - show the plan, show the costs, then decide. @ScottMorrisonMP @POTUS @JustinTrudeau don't have plan & costs, or don't want to reveal cost estimates. Hmm! #EnergyTransition will cost more.

> **Dan Tsubouchi** @Energy_Tidbits · Jun 23
>
> US can't control what CN IN actually spend to be #CarbonNeutral, but politics aside, shouldn't #Biden admin have a rough estimate of how many $trillions to get US to carbon neutral? How can anyone say #EnergyTransition won't cost more? #NatGas #OOTT
>
> ...

3 2

SAF

Dan Tsubouchi @Energy_Tidbits · Jul 20

great @JeffBezos line just now in the #BlueOrigin capsule on why he is going on 1st manned launch. "if the vehicle isn't safe for me, it's not safe for anyone". never heard it called a vehicle before. don't care how wealthy he is, it's impressive.

2

SAF

Dan Tsubouchi @Energy_Tidbits · Jul 20

"The positive activity momentum we see in North America and international markets today, combined with our expectations for future customer demand, gives us conviction for an unfolding multi-year upcycle." $HAL Q2 release, call is 9am ET. #OOTT #NatGas

Halliburton Announces Second Quarter 2021 Resul...
The Investor Relations website contains information about Halliburton's business for stockholders, ...
ir.halliburton.com

1 1 3

SAF

Dan Tsubouchi @Energy_Tidbits · Jul 19

Even if US #NatGas storage is close to 3 tcf on Oct 31, 2022, that is ~700 bcf less than normal. It makes 2023 #HenryHub strip of $2.81 & 2023 #AECO strip of C$2.55 look pretty cheap. Thx @BloombergNEF Nakul Nair for highlighting #SabinePassLNG Train 6 & #CalcasieuPassLNG

Dan Tsubouchi @Energy_Tidbits · Jul 19

2/2. If global LNG markets can take added volume, it has a huge impact on US #NatGas storage. @BloombergNEF Nakul Nair forecasts Oct 31/22 storage at 2.64 tcf, that ~1 tcf less than normal. Gas producers hope it will be like last time <3 tcf on Oct 31 2000. #LNG #AECO #HenryHub

Show this thread

1 2 6

Dan Tsubouchi @Energy_Tidbits · Jul 19

2/2. If global LNG markets can take added volume, it has a huge impact on US #NatGas storage. @BloombergNEF Nakul Nair forecasts Oct 31/22 storage at 2.64 tcf, that ~1 tcf less than normal. Gas producers hope it will be like last time <3 tcf on Oct 31 2000. #LNG #AECO #HenryHub

2 · 8

Show this thread

Dan Tsubouchi @Energy_Tidbits · Jul 19

1/2. Overlooked potential big upside to #HenryHub #AECO 2022 gas prices - #NatGas feedgas deliveries to #Cheniere #SabinePassLNG Train 6 (0.7 bcf/d) & #CalcasieuLNG (1.3 bcf/d) expected to start around yr end 2021 or early 2022. #LNG

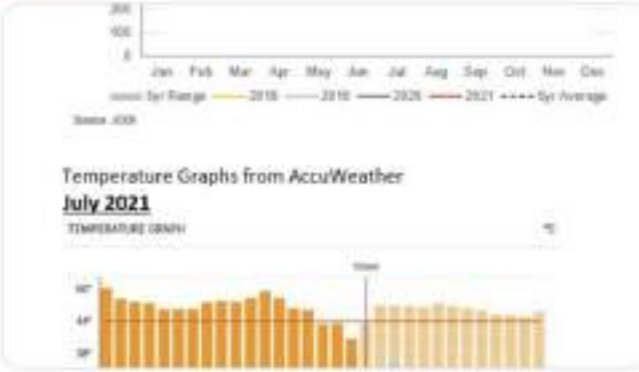
1 · 3 · 15

Show this thread

SAF

Dan Tsubouchi @Energy_Tidbits · Jul 19

Just moving into peak seasonal #Oil demand in KSA for use for electricity every summer. #JODI data shows 451,000 b/d in May (up from 407,000 in Apr). Peak is Aug/Sept as temps get hotter. Normal peak is ~700,000 b/d. #OOTT



SAF

Dan Tsubouchi @Energy_Tidbits · Jul 19

Another reason to worry about #LNGSupplyGap? Hopefully WA will give $CVX more time to catch up and let them offset with #CarbonCredits. If not, won't other potential WA fix-the-shortage actions seem to add risk to #GorgonLNG future recovery/rate? Thx @SStapczynski #LNG

> **Stephen Stapczynski** @SStapczynski · Jul 19
>
> The world's biggest project to capture and store carbon dioxide at an LNG export plant in Australia isn't working like it should 🇦🇺 🏭
>
> Energy companies have staked their net-zero futures on the technology, which has shown limited success to date
>
> bloomberg.com/news/articles/...
>
> Show this thread

1 4

Dan Tsubouchi @Energy_Tidbits · Jul 19

Worth a listen. @CroftHelima market can absorb 400,000 b/d per month, "this was a renewal of #OPEC+ vows", a constructive agreement says @CroftHelima to @SullyCNBC #OOTT

> **Worldwide Exchange** @CNBCWEX · Jul 19
>
> "We think the market can absolutely absorb the additional 400,000 barrels per month," says @CroftHelima on the recent output decision made by OPEC+ early Sunday morning.

5 17

Dan Tsubouchi @Energy_Tidbits · Jul 19

Here is the deleted screenshot. Thx @davidronta for clarifying its an oil & gas company comment. Still a great @SullyCNBC Random But Interesting as it is positive for #Oil price if institutions still don't want to give new capital for oil & gas investment. #OOTT

> **Dan Tsubouchi** @Energy_Tidbits · Jul 19
>
> Correction. @davidronta reminded that this is not the @DallasFed saying their close relationships, but rather an oil and gas company respondent. thx @davidronta. #OOTT twitter.com/Energy_Tidbits...

2 12

Dan Tsubouchi @Energy_Tidbits · Jul 19

Correction. @davidronta reminded that this is not the @DallasFed saying their close relationships, but rather an oil and gas company respondent. thx @davidronta. #OOTT twitter.com/Energy_Tidbits...

> This Tweet is unavailable.

1

SAF

Dan Tsubouchi @Energy_Tidbits · Jul 18

Reminder, Angola & Nigeria not expected to produce to new Aug quota. Based on #OPEC #MOMR Secondary Sources June production, Angola -219,000 b/d & Nigeria -197,000 b/d vs Aug quota. Thx @Bloomberg @JLeeEnergy for quota breakdown. #OOTT

Gabon	208	186	191	186	183	187	179	173	-7
IR Iran	2,356	1,888	2,003	2,214	2,443	2,432	2,437	2,470	33
Iraq	4,678	4,849	3,817	3,801	3,944	3,947	3,948	3,938	-10
Kuwait	2,687	2,432	2,290	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	1,790	1,879	1,434	1,418	1,408	1,455	1,407	1,399	-8
Saudi Arabia	9,794	9,182	8,952	8,440	8,503	8,122	8,481	8,906	425
UAE	3,064	2,862	2,515	2,618	2,644	2,613	2,640	2,680	40
Venezuela	796	500	488	517	507	491	518	528	10
Total OPEC	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]

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

Source: OPEC Monthly Oil Market Report July 2021

Bloomberg @TheTerminal

OPEC+ Output Targets for 2H and New Baselines for Cuts (Table)

2021-07-18 11:36:58.188 GMT

By Julian Lee

(Bloomberg) -- The table below shows the individual oil output targets for OPEC+ countries for the rest of this year, following the group's agreement to raise total supplies by 400k b/d each month from August. The figures are in thousands of barrels a day.

Target production Jul-21 Aug-21 Sep-21 Oct-21 Nov-21 Dec-21

1

SAF

Dan Tsubouchi @Energy_Tidbits · Jul 18

Reminder, #NatGas power generation is needed right now more than normal to fill #Solar shortfalls. Wildfires = less solar generation. Rule of thumb, Sept 2020, @EIAgov estimated #solar generation was down 30% from CA wildfires. #EnergyTransition

eia.gov/todayinenergy/...

1 9

Dan Tsubouchi @Energy_Tidbits · Jul 18

Our weekly SAF July 11, 2021 Energy Tidbits memo was just posted to our SAF Group website. This 41-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

SAF

Energy Tidbits

July 18, 2021

BlackRock's Fink Raises Risk of $100, $125 Oil If Govts Keep Forcing Supply Down But Can't/Don't Force Down Demand

2

6