Energy Tidbits

June 20, 2021

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Supplemental Documents

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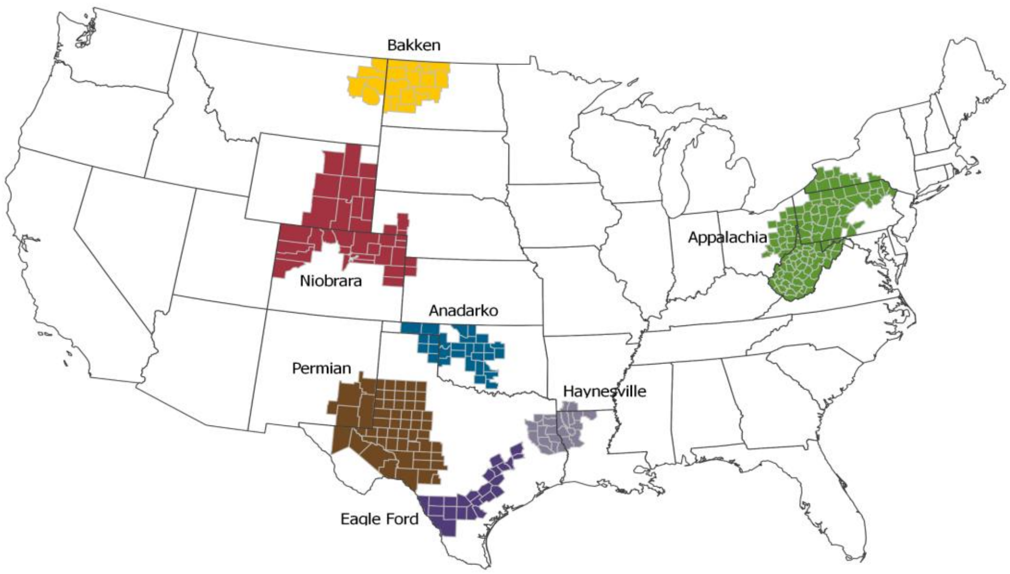
Independent Statistics & Analysis

U.S. Energy Information Administration

June 2021

Drilling Productivity Report

For key tight oil and shale gas regions



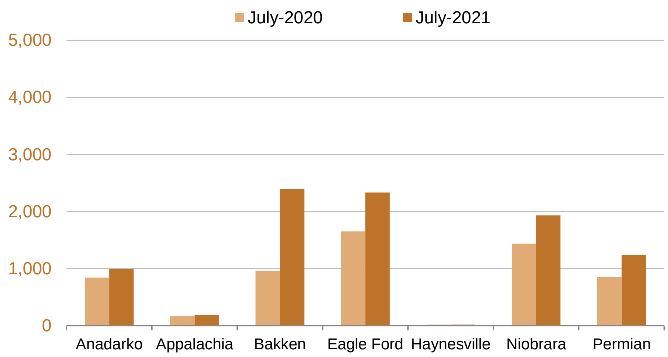
Note:

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

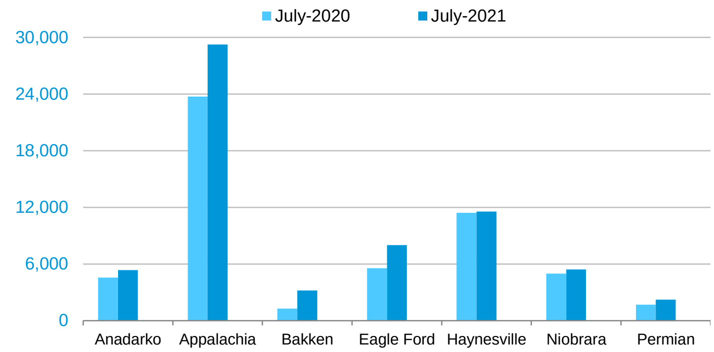
The DPR metric *legacy oil/gas production change* can become unstable during periods of rapid decreases or increases in the volume of well production curtailments or shut-ins. This effect has been observed during winter weather freeze-offs, extreme flooding events, and the 2020 global oil demand contraction.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

Contents

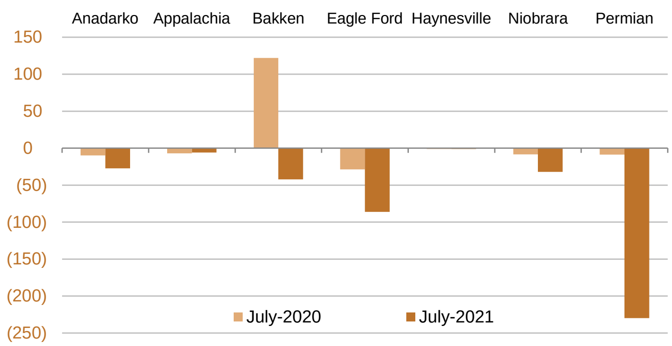
New-well oil production per rig
barrels/day



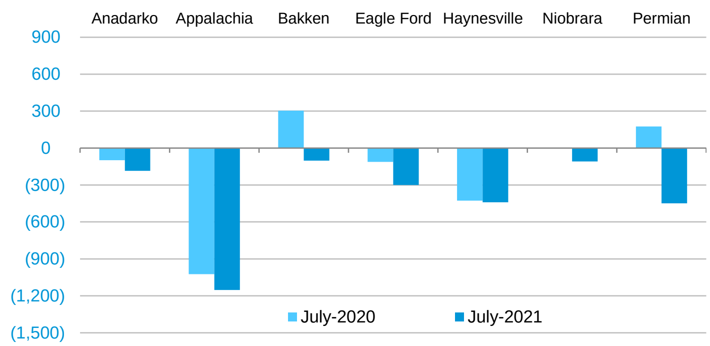
New-well gas production per rig
thousand cubic feet/day



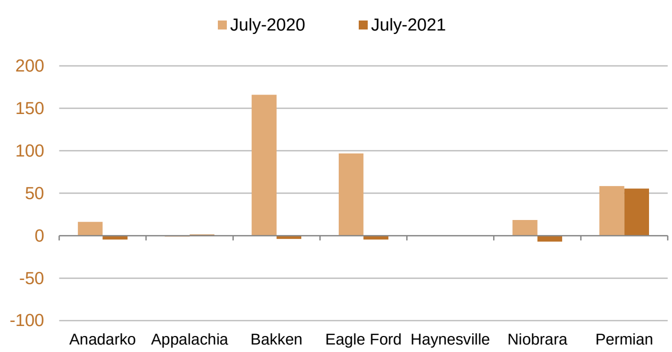
Legacy oil production change
thousand barrels/day



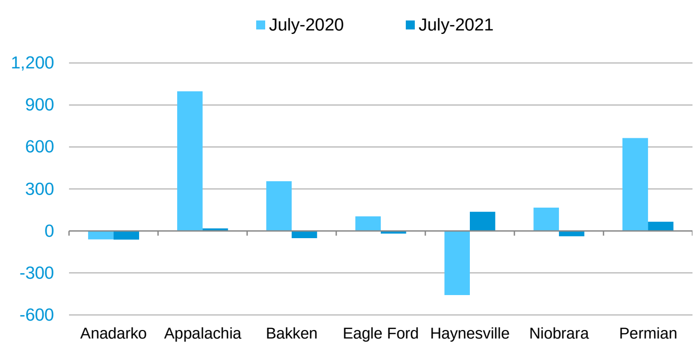
Legacy gas production change
million cubic feet/day



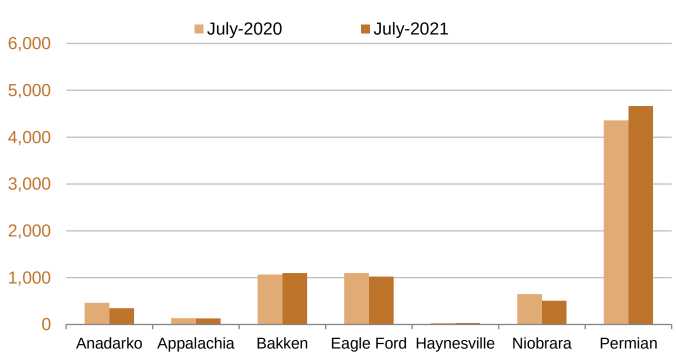
Indicated monthly change in oil production (Jul vs. Jun)
thousand barrels/day



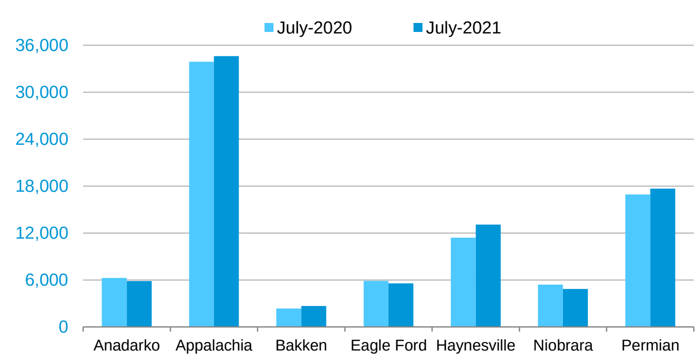
Indicated monthly change in gas production (Jul vs. Jun)
million cubic feet/day



Oil production
thousand barrels/day



Natural gas production
million cubic feet/day



Anadarko Region

Drilling Productivity Report

June 2021

drilling data through May
projected production through July

Oil -19
barrels/day
month over month

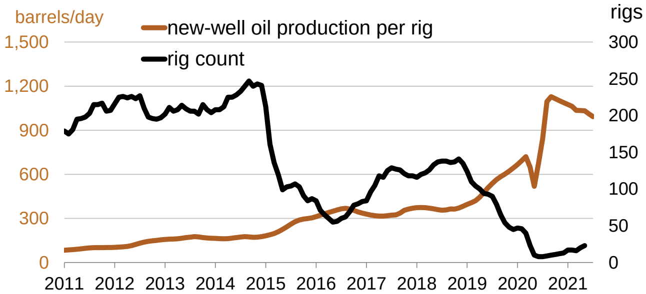
993 *July*
1,012 *June*
barrels/day

Monthly additions from one average rig

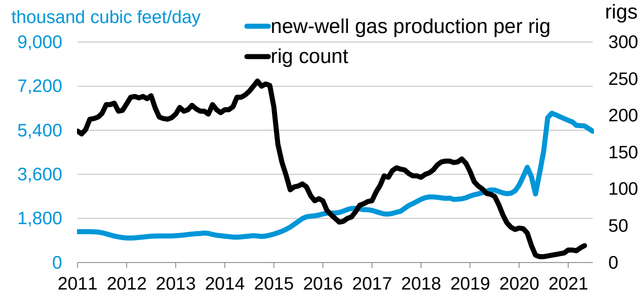
July **5,358**
June **5,467**
thousand cubic feet/day

Gas -109
thousand cubic feet/day
month over month

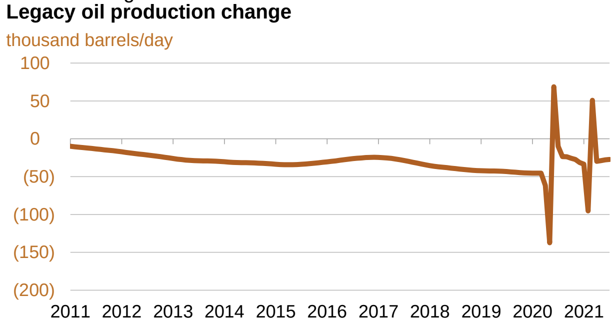
Anadarko Region
New-well oil production per rig **Rig count**



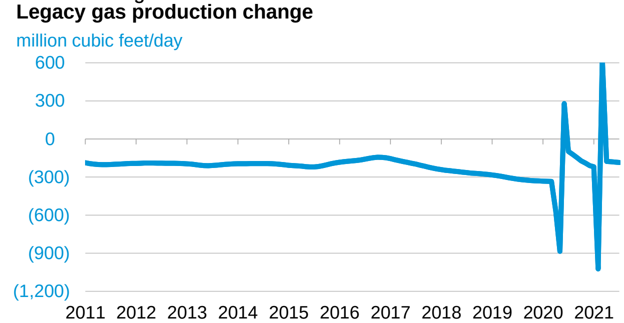
Anadarko Region
New-well gas production per rig **Rig count**



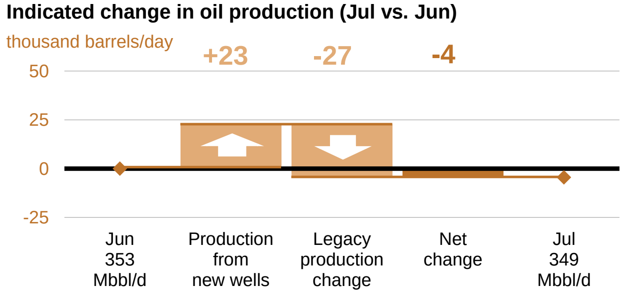
Anadarko Region
Legacy oil production change



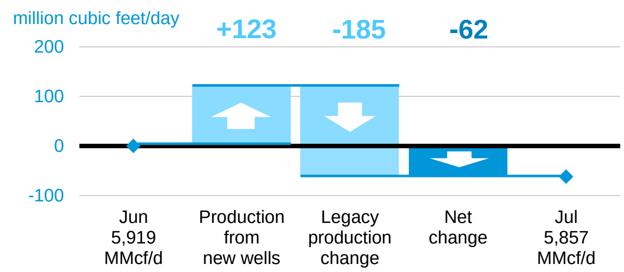
Anadarko Region
Legacy gas production change



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

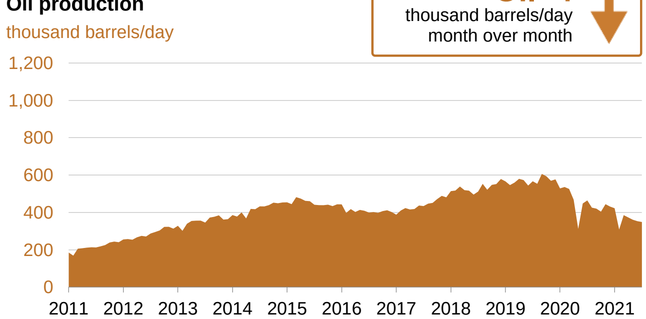


Anadarko Region
Indicated change in natural gas production (Jul vs. Jun)



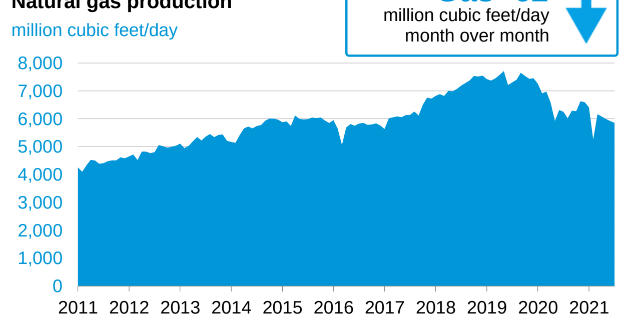
Anadarko Region
Oil production

Oil -4
thousand barrels/day
month over month



Anadarko Region
Natural gas production

Gas -62
million cubic feet/day
month over month



Appalachia Region

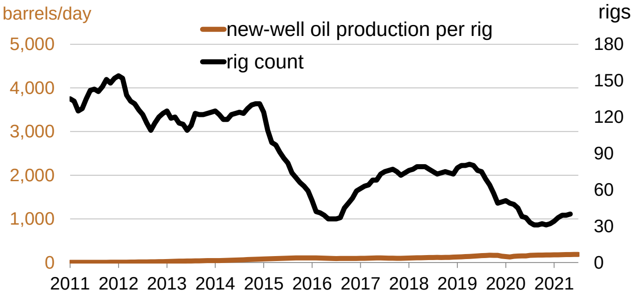
Drilling Productivity Report

June 2021

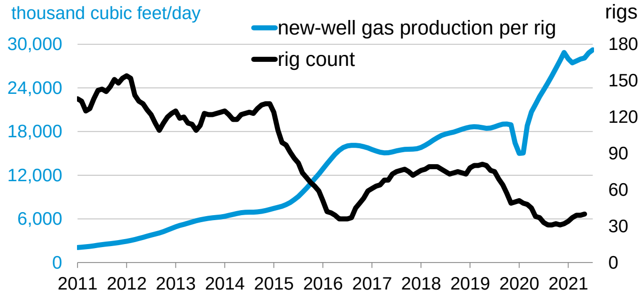
drilling data through May
projected production through July

Oil +1 barrels/day month over month	**186** *July* **185** *June* barrels/day	**Monthly additions from one average rig**	*July* **29,240** *June* **28,808** thousand cubic feet/day	**Gas +432** thousand cubic feet/day month over month

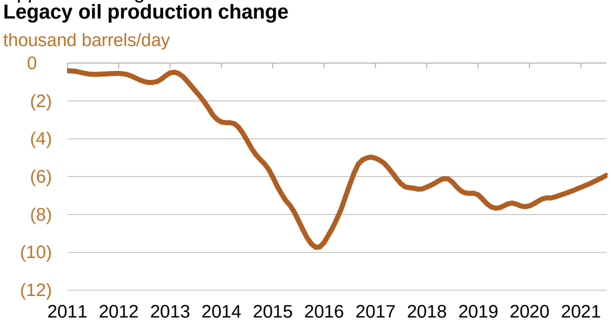
Appalachia Region
New-well oil production per rig



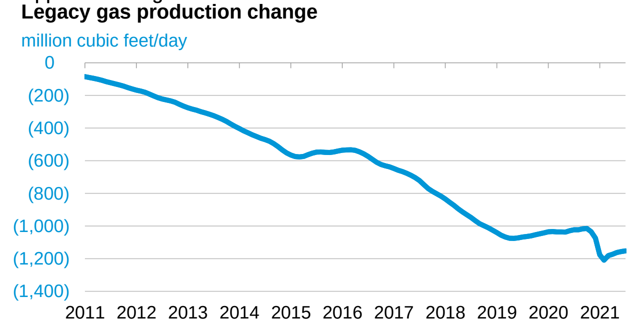
Appalachia Region
New-well gas production per rig



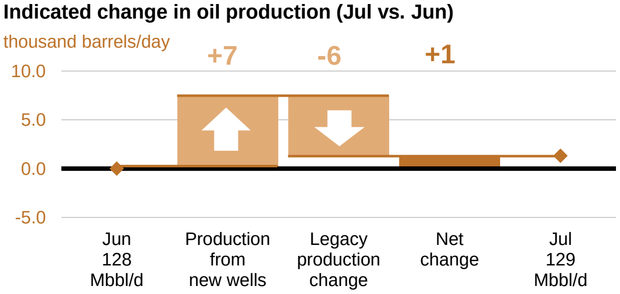
Appalachia Region
Legacy oil production change



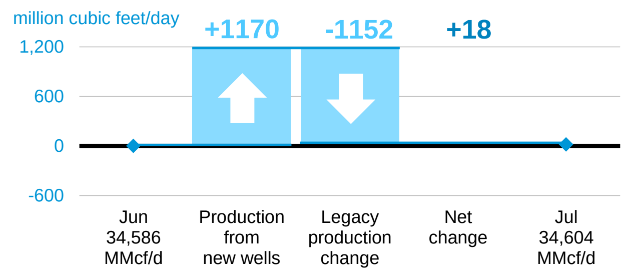
Appalachia Region
Legacy gas production change



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

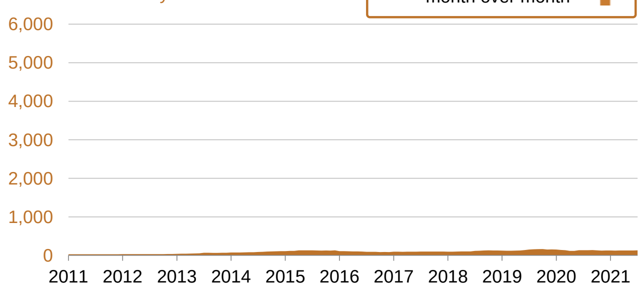


Appalachia Region
Indicated change in natural gas production (Jul vs. Jun)



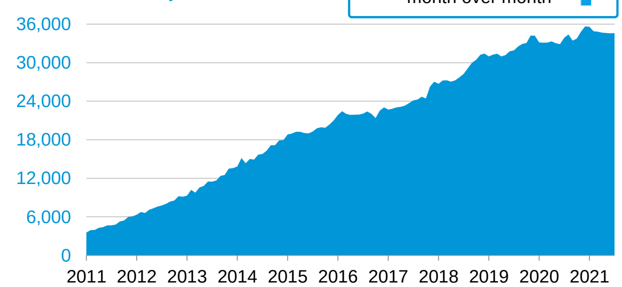
Appalachia Region
Oil production

Oil +1
thousand barrels/day
month over month



Appalachia Region
Natural gas production

Gas +18
million cubic feet/day
month over month



Bakken Region

Drilling Productivity Report

June 2021

drilling data through May
projected production through July

Oil
-13
barrels/day
month over month

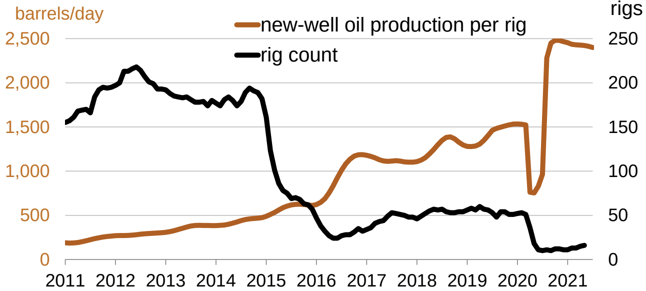
2,400 *July*
2,413 *June*
barrels/day

Monthly additions from one average rig

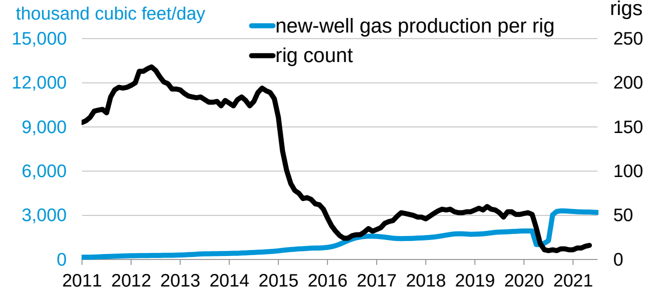
July **3,192**
June **3,210**
thousand cubic feet/day

Gas
-18
thousand cubic feet/day
month over month

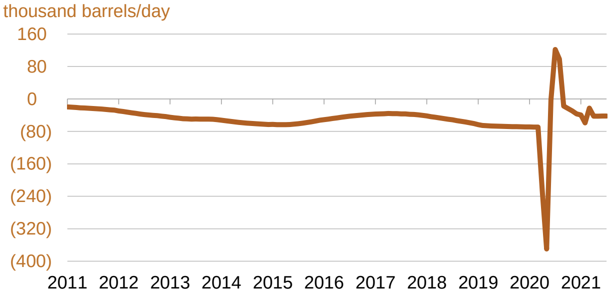
Bakken Region
New-well oil production per rig **Rig count**



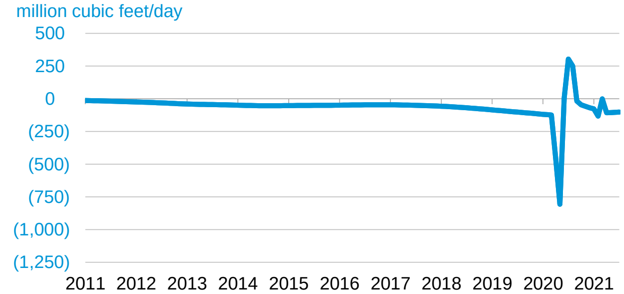
Bakken Region
New-well gas production per rig **Rig count**



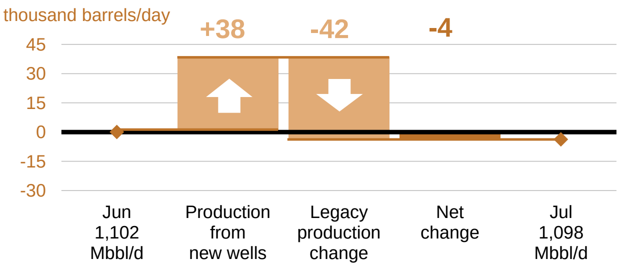
Bakken Region
Legacy oil production change



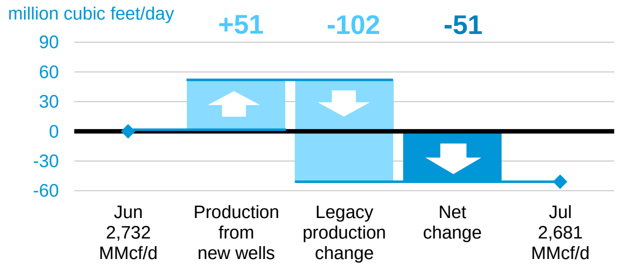
Bakken Region
Legacy gas production change



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

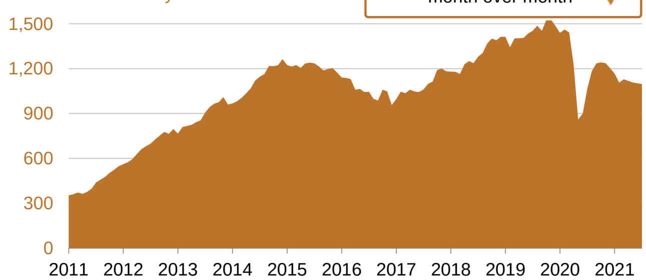


Bakken Region
Indicated change in natural gas production (Jul vs. Jun)



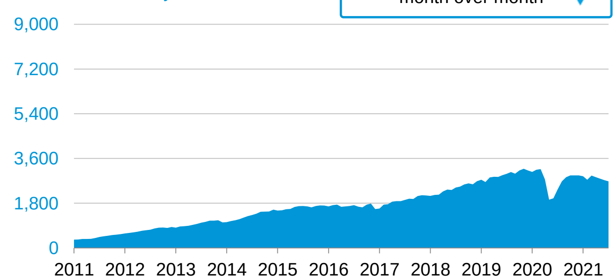
Bakken Region
Oil production

Oil -4
thousand barrels/day
month over month



Bakken Region
Natural gas production

Gas -51
million cubic feet/day
month over month



Eagle Ford Region

Drilling Productivity Report

June 2021

drilling data through May
projected production through July

Oil +1 barrels/day month over month

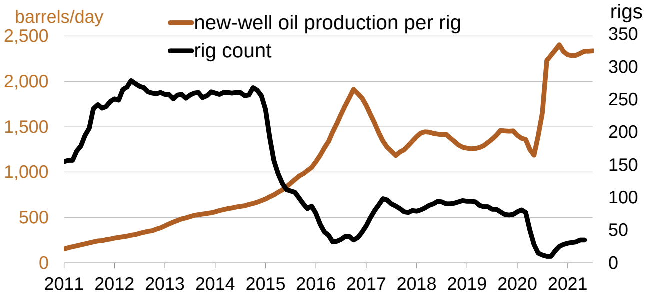
2,335 July
2,334 June
barrels/day

Monthly additions from one average rig

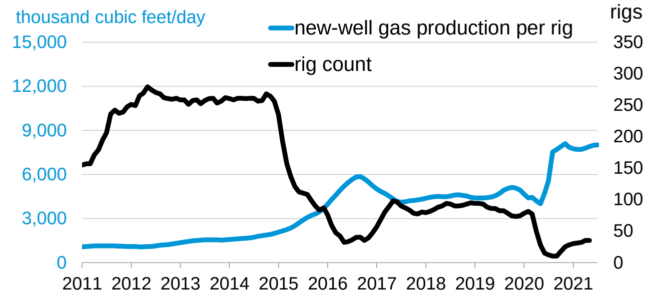
July **8,003**
June **7,980**
thousand cubic feet/day

Gas +23 thousand cubic feet/day month over month

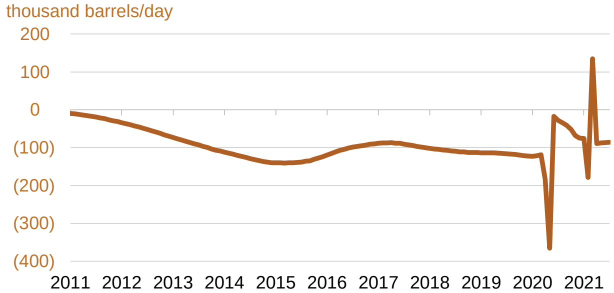
Eagle Ford Region
New-well oil production per rig
Rig count



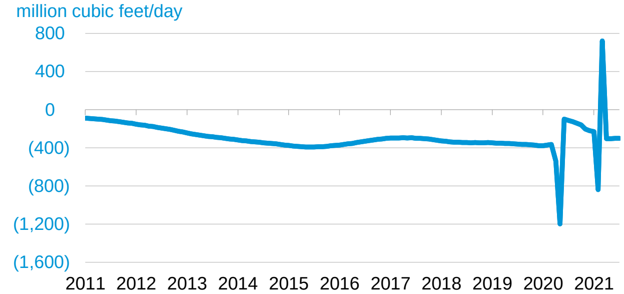
Eagle Ford Region
New-well gas production per rig
Rig count



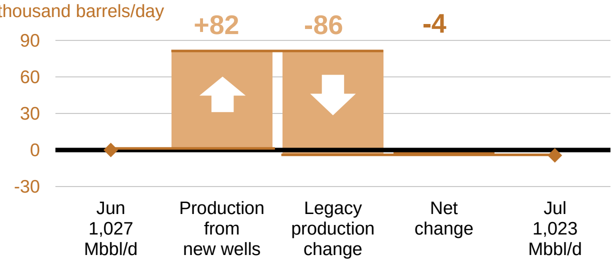
Eagle Ford Region
Legacy oil production change



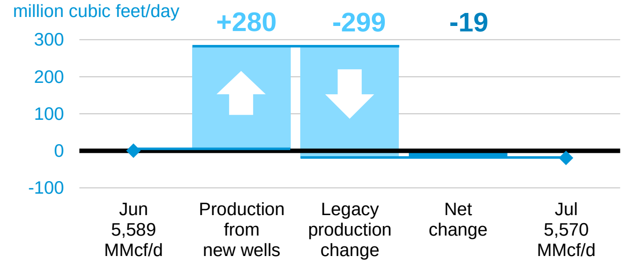
Eagle Ford Region
Legacy gas production change



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

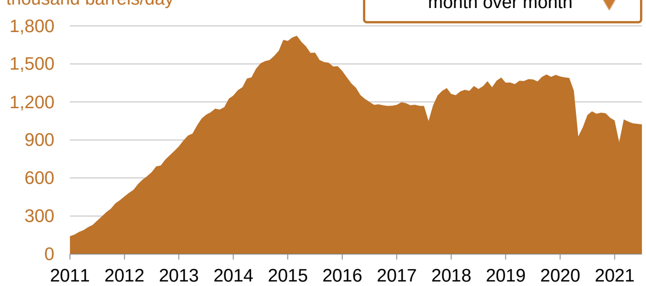


Eagle Ford Region
Indicated change in natural gas production (Jul vs. Jun)



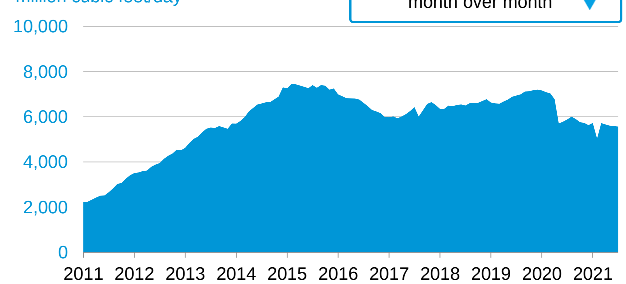
Eagle Ford Region
Oil production

Oil -4 thousand barrels/day month over month



Eagle Ford Region
Natural gas production

Gas -19 million cubic feet/day month over month



Haynesville Region

Drilling Productivity Report

June 2021

drilling data through May
projected production through July

Oil
0
barrels/day
month over month

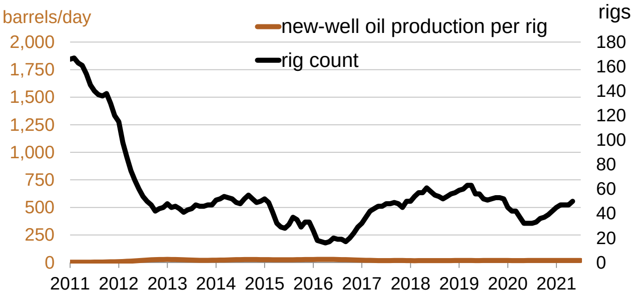
19 *July*
19 *June*
barrels/day

Monthly additions from one average rig

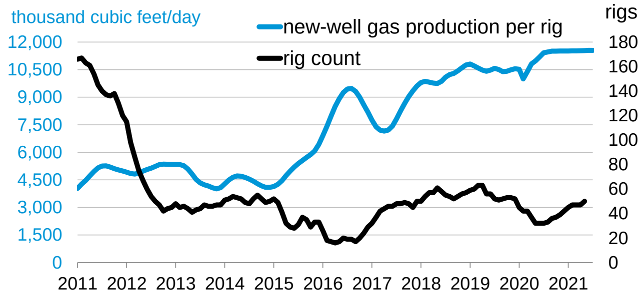
July **11,549**
June **11,548**
thousand cubic feet/day

Gas
+1
thousand cubic feet/day
month over month

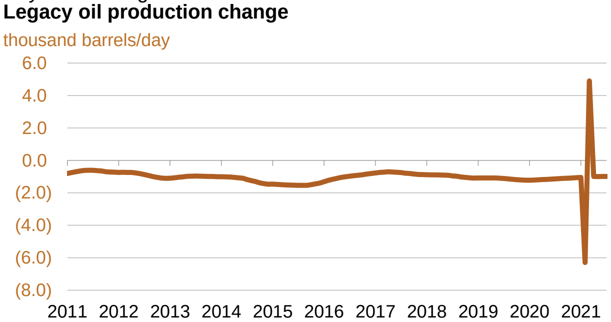
Haynesville Region
New-well oil production per rig



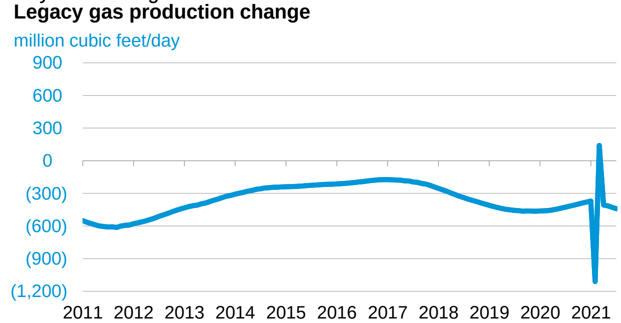
Haynesville Region
New-well gas production per rig



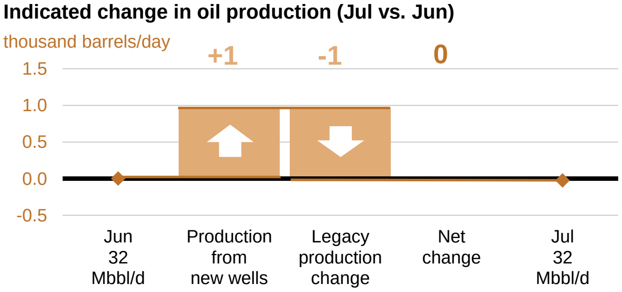
Haynesville Region
Legacy oil production change



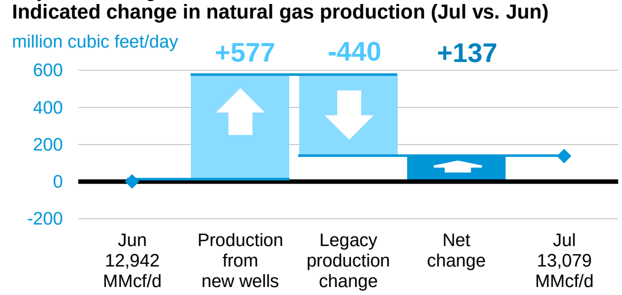
Haynesville Region
Legacy gas production change



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

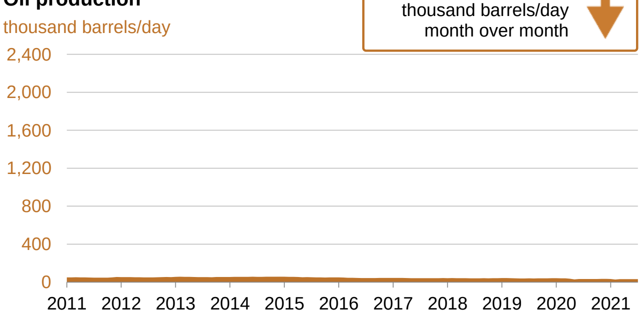


Haynesville Region
Indicated change in natural gas production (Jul vs. Jun)



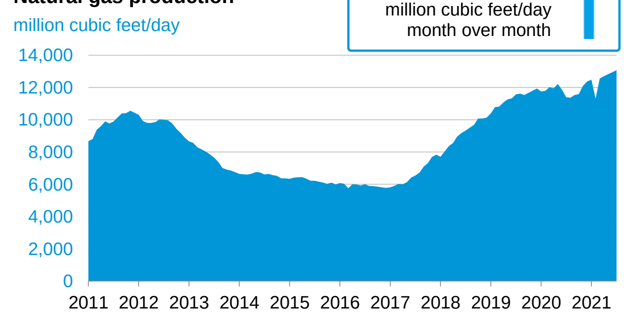
Haynesville Region
Oil production

Oil 0
thousand barrels/day
month over month



Haynesville Region
Natural gas production

Gas +137
million cubic feet/day
month over month



Niobrara Region

Drilling Productivity Report

June 2021

drilling data through May
projected production through July

Oil
-1
barrels/day
month over month

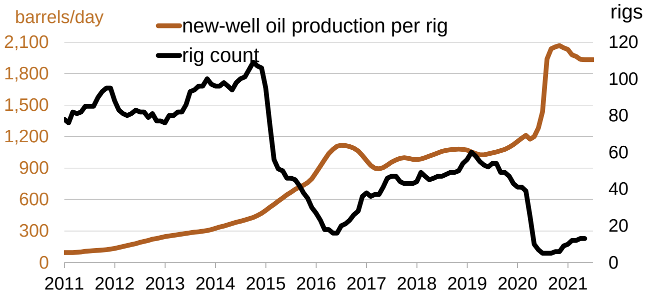
1,932 *July*
1,933 *June*
barrels/day

Monthly additions from one average rig

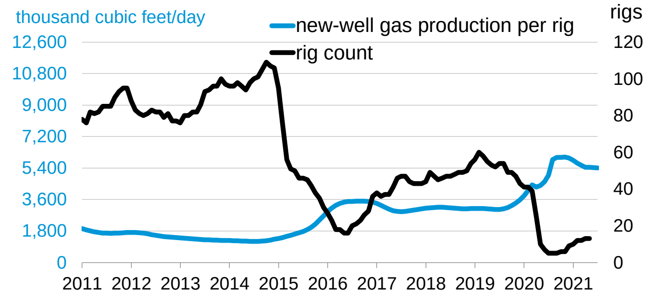
July **5,415**
June **5,426**
thousand cubic feet/day

Gas
-11
thousand cubic feet/day
month over month

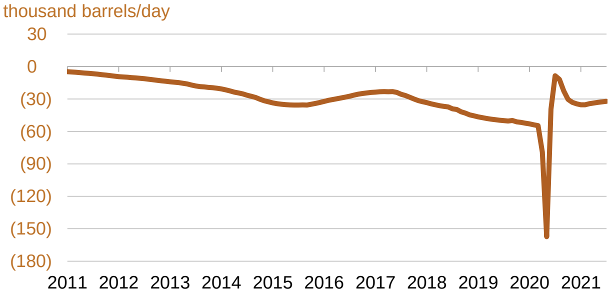
Niobrara Region
New-well oil production per rig **Rig count**



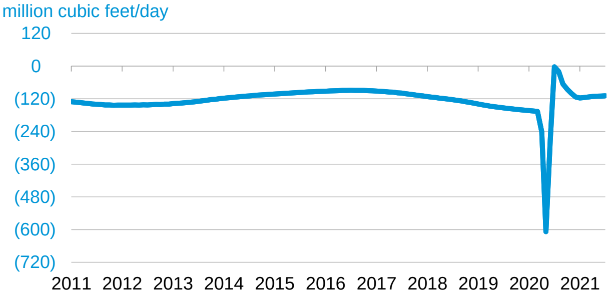
Niobrara Region
New-well gas production per rig **Rig count**



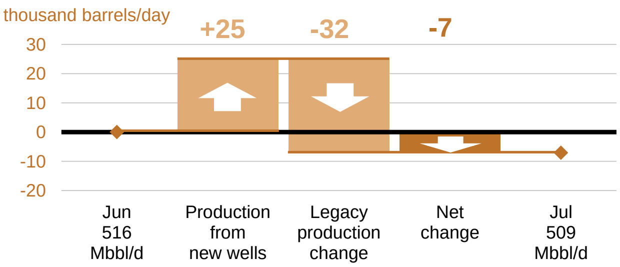
Niobrara Region
Legacy oil production change



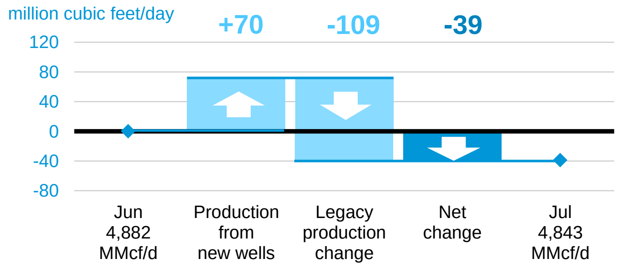
Niobrara Region
Legacy gas production change



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

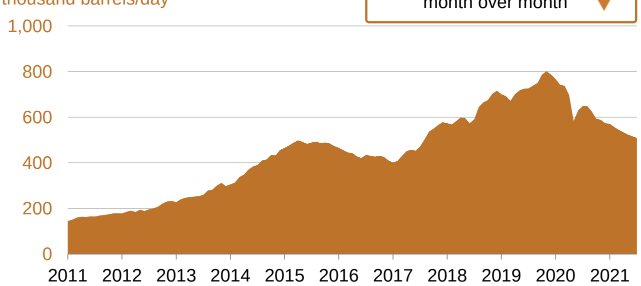


Niobrara Region
Indicated change in natural gas production (Jul vs. Jun)



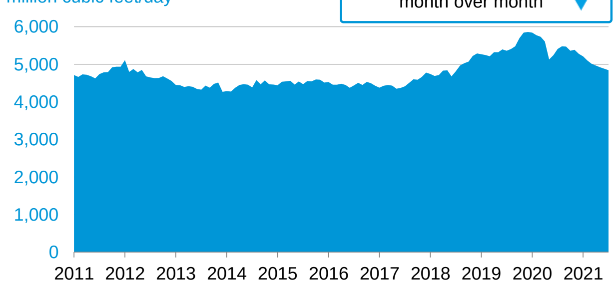
Niobrara Region
Oil production

Oil -7
thousand barrels/day
month over month



Niobrara Region
Natural gas production

Gas -39
million cubic feet/day
month over month



Permian Region

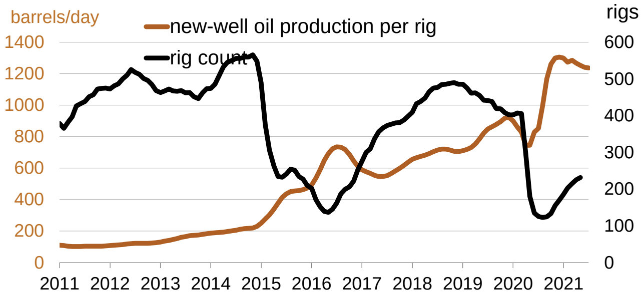
Drilling Productivity Report

June 2021

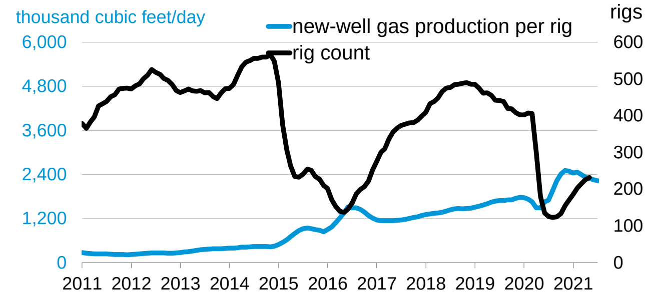
drilling data through May
projected production through July

Oil	1,235 *July*	Monthly additions from one average rig	*July* 2,229	Gas
-5	1,240 *June*		*June* 2,250	-21
barrels/day month over month	barrels/day		thousand cubic feet/day	thousand cubic feet/day month over month

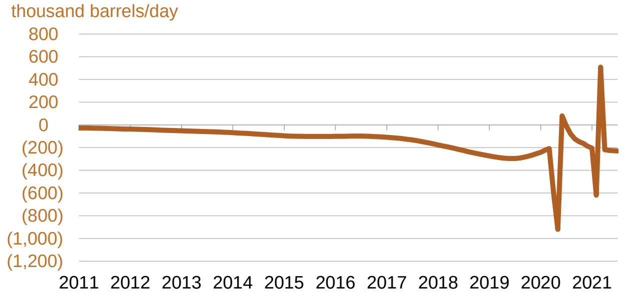
Permian Region
New-well oil production per rig



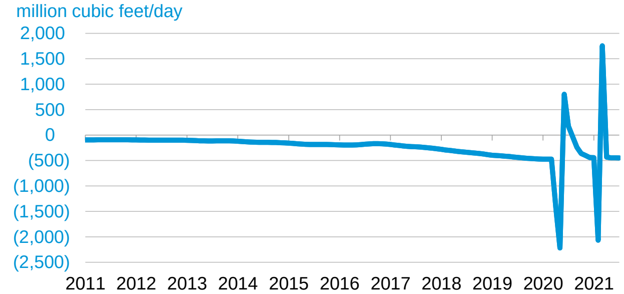
Permian Region
New-well gas production per rig



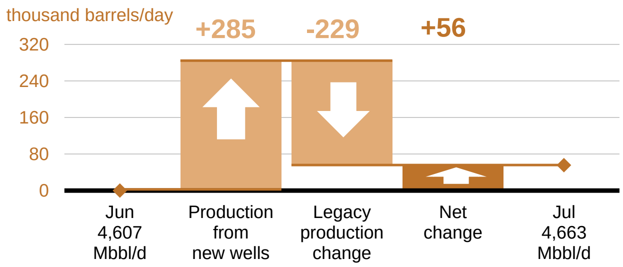
Permian Region
Legacy oil production change



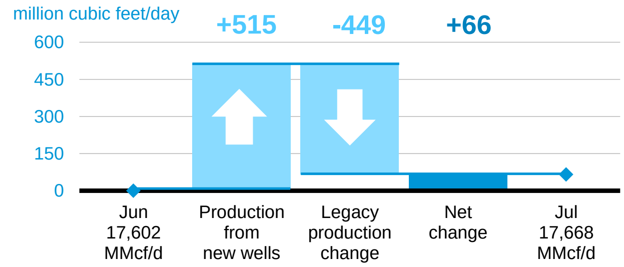
Permian Region
Legacy gas production change



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

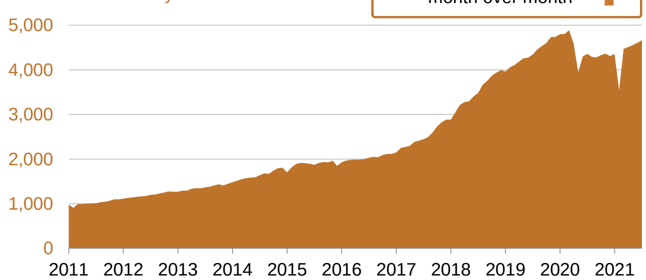


Permian Region
Indicated change in natural gas production (Jul vs. Jun)



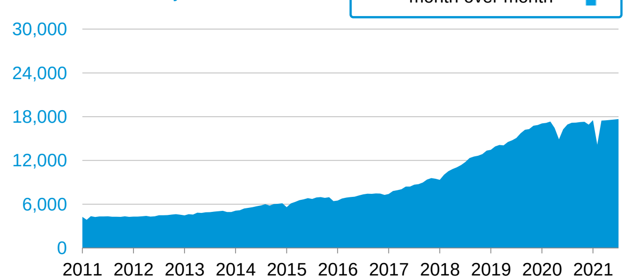
Permian Region
Oil production

Oil +56
thousand barrels/day
month over month



Permian Region
Natural gas production

Gas +66
million cubic feet/day
month over month



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

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

New-well oil/gas production per rig
Charts present historical estimated monthly additions from one average rig coupled with the number of total drilling rigs as reported by Baker Hughes.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Oklahoma Corporation Commission (http://www.occeweb.com/og/oghome.htm) Source of well production, permit, and completion data in the counties associated with this report in Oklahoma https://rbnenergy.com/only-the-strong-survive-part3-how-covid19-reshaped-the-future-of-north-american-lng-projects

Only The Strong Survive, Part 3 - How COVID-19 Reshaped The Future Of North American LNG Projects

Monday, 06/14/2021
Published by: Lindsay Schneider

Appetite for new North American LNG export capacity had been waning already when COVID-19 brought it to a screeching halt. The global gas market was expected to be well-oversupplied through the mid-2020s as U.S. liquefaction capacity additions, combined with supply growth from Australian LNG projects, were far outpacing any increase in demand. However, the past year or so has proven how quickly things can swing from oversupplied to undersupplied. The extended run of high global gas prices is bringing renewed interest in expanding North American LNG export capacity. Although COVID dashed the prospects of many LNG projects, a handful have emerged from the morass of the past year stronger and with a clearer path to FID than ever before. Those that remain will be better positioned if they can navigate four emerging trends that are key for offtaker agreements in the post-COVID era: shorter contract terms, increased pricing or deal-structure diversity, reduced environmental impact, and a prioritization of brownfield expansions or phased greenfield projects. Today, we conclude the series on the status of the second wave of LNG projects.

So far in this series, we have focused on the eight LNG projects under development that we believe have the most likely shot at reaching an eventual final investment decision (FID). In Part 1, we focused on the two projects that we categorize as "probable" (i.e., likely to reach FID this year): Woodfibre LNG and Cameron LNG Phase 2. Woodfibre has more than 70% of its capacity secured in firm long-term sales and purchase agreements (SPAs) with BP, while Cameron has credible, non-binding agreements equivalent to the full capacity of the expansion with the terminal's existing offtakers: TotalEnergies, Mitsui, and Mitsubishi. Due to their strong commercial position, both of these projects could realistically take FID in the next six months. In Part 2, we rounded up the other six projects that have demonstrated momentum toward an FID — perhaps not in the next six months but in the mid-term. We categorize these facilities as "Tier 1" and "Tier 2" based on how far they are into their development, particularly on commercial agreements. These have the needed regulatory approvals in hand, along with reasonable access to feedgas supply, which are the two other metrics we use to grade prospective LNG projects in our LNG Voyager Quarterly supplement. Specifically, there are four projects we place as Tier 1: Cheniere Energy's Corpus Christi Stage III expansion, Sempra Energy's Port Arthur LNG, Freeport LNG's Train 4 buildout, and Tellurian's Driftwood LNG. And then, there are two projects we consider Tier 2: Venture Global's Plaquemines LNG and NextDecade's Rio Grande LNG.

All eight projects, along with Sempra's recently green-lighted Energía Costa Azul (ECA) LNG, have something in common: just about all of them have had to adapt their strategy to better compete for commercial commitments or SPAs with ever-pickier offtakers. Their forward momentum highlights the four main project features we named earlier that developers are offering as they strive toward FID: shorter contract terms, increased pricing or deal-structure diversity, reduced environmental impact, and a prioritization of brownfield expansions or phased greenfield projects that are scaling down the capacity for initial start-up. The projects we're discussing today have homed in on at least one of these facets as part of their overall strategy to achieve FID, but most capitalize on multiple angles in order to make themselves look as attractive as possible to offtakers. The table in Figure 1 summarizes the ways in which they have incorporated the four metrics. A filled-in green circle indicates that the developers are very committed to that particular strategy, while an unfilled circle indicates that there has been at least some progress in that aspect. An empty cell means either that there has been no development or that no information has been provided publicly regarding that strategy. It is likely that most projects are exploring all four strategies but have not announced anything firm yet. While some developers share the structure of their offtake agreements others do not, so we simply don't know what we don't know here. Additionally, many of these projects had offtake agreements in place before the pandemic, and it's likely that any new offtake agreements will look different than the original deals already made. That has certainly been the case for Driftwood LNG, which was selling equity stakes in the project before the pandemic and is now selling 10-year SPAs indexed to global gas prices. Below, we'll dive into each of the strategies, specifically highlighting examples of how they're being utilized by project developers.

LNG Project Development Strategies to Reach FID					
Project	Status	Shorter offtake agreements	Pricing/SPA structure diversity	ESG Friendly	Reduced project scope
ECA LNG	FID	○			●
Woodfibre	Probable			●	●
Cameron T4-5	Probable				●
Corpus Christi Ph 3	Tier 1	○	○	○	●
Port Arthur Ph 1	Tier 1				○
Freeport Train 4	Tier 1				●
Driftwood Ph1	Tier 1	●	●		○
Plaquemines Ph1	Tier 2			○	○
Rio Grande	Tier 2			●	

Figure 1. North American LNG Project Development Strategies Matrix. Source: RBN

Shorter terms for SPAs

As with many developments in North American LNG, Cheniere is at the forefront of the trend toward shorter terms for SPAs. The company has had tremendous success in selling what it calls medium-term SPAs for capacity at its existing terminals, namely offtake agreements with 5- to 11-year terms. But these shorter-term deals are being explored by new terminals as well. They are hugely popular with offtakers because of the uncertainties in long-term supply and demand. As we said at the outset, they've been whipsawed by those changing dynamics in the last couple of years. A mid-term deal provides an offtaker energy security for now, with consistent access to gas and protection from price volatility, while allowing them flexibility in the long term to respond to macroeconomic developments such as changing regulations and emerging clean energy technology (check out last week's blog, My Favorite Mistake for more on how and why LNG deal pricing and terms have evolved). The three most recent SPAs announced for pre-FID terminals have all been shorter than the standard 20-year deals seen among the first wave of projects. In April, Woodfibre closed an SPA with BP for a 15-year term. Just in the past month, Tellurian announced two new 10-year SPAs supporting Driftwood LNG for 3 MMtpa each: one with Gunvor and one with Vitol.

Price/deal structure diversity

The push toward price and deal structure diversity is a continuation of the trend that helped bring U.S. LNG to the forefront. Before the U.S. became an LNG supplier, LNG was typically sold at prices indexed to oil. New U.S. terminals allowed for contracts to be indexed to the U.S. natural gas benchmark Henry Hub instead, providing end-users with portfolio diversity. However, amid increasing supply competition and price volatility, buyers are seeking still greater optionality for long-term contracts. New deals are now being penned linked to a variety of global gas prices, including the Japan Korea Marker (JKM) and European benchmarks such as the U.K. National Balancing Point (NBP) and the Dutch Title Transfer Facility (TTF). The pricing options help further diversify portfolios and share price risk between buyers and sellers. Moreover, even in cases where contracts use Henry Hub-linked prices, new deal structures are being explored in order to attract offtakers looking to spread the price risk.

As the table in Figure 1 shows, two of the project frontrunners have demonstrated pricing or deal-structure flexibility. In terms of pricing, under Tellurian's SPA with Vitol for Driftwood LNG, gas was sold at a price indexed to a blend of TTF and JKM. (Unrelated to these projects but also worth noting is Petronas's recent cargo sale at a price linked to AECO, which is the most liquid pricing point in Western Canada.) Note that a blank cell in the table above indicates that a project either definitively has Henry Hub-linked contracts or that there is no information available. In the latter case, the contracts are most likely to be linked to Henry Hub, directly or indirectly, simply because we are talking about North American (mostly U.S.) projects. Even in the case of tolling contracts, the offtaker is securing its own feedgas in North America (which is by nature at least somewhat linked to Henry Hub).

As for unique deal structures, the two contracts Cheniere has signed specifically for Corpus Christi Stage III are Integrated Production Management (IPM) agreements, a new type of contract that the company introduced for the project where a U.S. gas producer provides the feedgas to the terminal and Cheniere produces and markets the LNG on its behalf for a fee. This is not only a different type of deal structure than the way it's been done before — i.e., the traditional tolling or Cheniere's hybrid model of SPAs (see Steady as She Goes, Part 2 for more on those contract structures) — but it also opens up a new type of LNG customer. Of course, Cheniere still has to market this gas, either by using its medium-term agreements, selling it in the spot market, or securing additional SPAs for the project.

Increased emphasis on reducing environmental impact

LNG producers, offtakers, and developers are exploring a variety of options to help minimize or offset their carbon footprint (see Don't Fear the Reaper, Part 2). In April, Shell sold the first carbon-neutral LNG cargo produced at Sabine Pass, using carbon credits to offset its emissions. And beginning in 2022, Cheniere will provide all of its customers with a "carbon emission tag" with the estimated carbon produced for the full lifecycle of each cargo from wellhead production to delivery. As an extension of this, last week, Cheniere announced that it was partnering with several major U.S. gas producers to better monitor, report, and cut greenhouse gas emissions. The initiative will use a variety of monitoring technologies to better establish baseline emissions for natural gas production.

Proposed projects are also exploring ways to minimize their carbon footprints. Woodfibre will use hydroelectricity to power its liquefaction project, which would reduce the plant's emissions by 90% compared to a traditional LNG terminal, according to the project's developer, Pacific Oil and Gas. The most visible of these efforts to "go green" is perhaps that of Rio Grande LNG, which has proposed using carbon-capture and storage (CCS) technology if it goes ahead. Venture Global has also proposed a CCS system for Plaquemines LNG, albeit on a much smaller scale than Rio Grande. This trend will continue as end-users are increasingly interested in and incentivized by their governments to use greener sources of energy and reduce carbon emissions.

Smaller, phased projects or existing terminal expansions

The trend toward smaller, phased projects or existing terminal expansions is also an extension of what made the first wave of U.S. LNG possible. Most U.S. export terminals online today were converted from previously operating import terminals. Such conversions are much less expensive than greenfield expansions. Similarly, expanding a currently operating terminal is cheaper than building a brand new one. Three of the seven projects on our list above are expansions of existing U.S. terminals. In addition to having a lower price tag to build than a brand-new terminal, their respective developers have proven themselves throughout a very trying year and have an advantage over new market participants.

If you are planning to build a large new terminal project, it will be extremely difficult to reach FID all at once. This is actually not an entirely new phenomenon. Sabine Pass, the largest U.S. export facility, had four separate FIDs on its six trains, including the five that are currently operational and one that is under construction. The largest amount of capacity that we have seen reach FID all at once in the U.S. is the 15.6 MMtpa that was greenlighted at Golden Pass's three-train project on the site of its existing import facility.

There are five projects on the list that are either greenfield facilities or first-time conversions of existing import facilities (solid green dots in the far-right column in Figure 1). Woodfibre is a small single-train terminal, and like the first-wave projects and one of the few second-wave projects to take FID, ECA LNG, it had the advantage of being a brownfield conversion from an existing import terminal. All the other projects, except NextDecade's Rio Grande LNG, have been split into phased development. But even Rio Grande is unlikely to achieve FID all at once as NextDecade appears to be taking the Sabine Pass strategy. While the project has not formally been split into phases, it will likely reach FID on two of the five trains first, if it goes ahead.

Combining elements across these four developmental trends make prospective projects more attractive to offtakers and have given the eight projects covered in this series a path ahead toward reaching FID. With fundamentals supporting higher global prices (see Summertime for more) and the existing U.S. fleet back to operating at full capacity (barring maintenance events), the outlook for LNG terminals and expansions under development looks much better than it has since before the pandemic. That said, no one has forgotten the past two years. Developers and projects have to prove themselves, and it is by no means an easy environment for new LNG development. However, the currently undersupplied global market with its extended run of higher gas prices, has brought offtakers back to the negotiating table with renewed interest. We have not seen the last project in North America take FID. ECA is already under construction, and the two probable projects, Cameron Phase 2 and Woodfibre LNG, could take FID this year, with any number of the Tier 1 and 2 projects to follow in the next 1-3 years.

"Only the Strong Survive" was written by Jerry Butler, Kenny Gamble, and Leon Huff. It was the third song on Butler's 11th studio album, *The Ice Man Cometh*. It was released as a single in March 1969 and went to #1 on the Hot R&B Singles chart and #4 on the Billboard Hot 100 Singles chart. It was the most successful single of Butler's career and has been certified Gold by the Recording Industry Association of America. Artists such as Elvis Presley, Skeeter Davis, Billy Paul, and The Trammps have covered the song. Personnel on the record were: Jerry Butler (lead vocals), Curtis Mayfield (lead guitar), Norman Harris, Bobby Eli (guitar), Ronnie Baker (bass), Earl Young (drums), Leon Huff (piano), and Vince Montana (vibes).

The Ice Man Cometh was recorded between September 1967 and September 1968 at Bell Sound Studio in New York City and Cameo-Parkway Studios and Sigma Sound Studio in Philadelphia. Kenny Gamble and Leon Huff produced the record. Released in November 1968, it went to #2 on the R&B Album chart and #29 on the Billboard Top 200 Albums chart. Three singles were released from the album.

Jerry Butler is an American soul singer, songwriter, record producer, musician, and retired politician. He was the original lead vocalist for The Impressions and was inducted with the R&B group into the Rock and Roll Hall of Fame in 1991. Since leaving the group in 1960 to pursue the career of a solo artist, Butler has had over 50 charting Billboard hits. He was inducted into the Rhythm and Blues Hall of Fame in 2015. From 1985 to 2018, he served as a commissioner for Cook County, Illinois. He has released 34 studio albums and 75 singles as a solo artist. Butler, 81, is now retired and lives in Chicago.

https://www.reuters.com/article/us-mozambique-lng-galp-energia/exclusive-galp-says-it-wont-invest-in-rovuma-until-mozambique-ensures-security-idUSKCN2DQ1JQ

JUNE 14, 20219:31 AMUPDATED 3 HOURS AGO

Exclusive: Galp says it won't invest in Rovuma until Mozambique ensures security

By Sergio Goncalves 3 MIN READ

LISBON (Reuters) - Portugal's Galp Energia, a partner in an Exxon Mobil-led gas consortium in Mozambique, will not invest in onshore plants there until authorities guarantee security and social stability, which may take time, CEO Andy Brown told Reuters.

The logo of GALP is seen next to a petrol station of GALP company near Lisbon, Portugal July 30, 2018. REUTERS/Rafael Marchante/Files

This marks a second setback to Mozambique's hopes to develop a major LNG gas hub in the coming years after TotalEnergies suspended its own, separate LNG project in the country.

Attacks by militants in northern Mozambique's Cabo Delgado region, near the $30 billion Rovuma liquefied natural gas project, have forced hundreds of thousands of people to flee the area.

The Mozambican government has said it expects the consortium to take the final investment decision, already postponed from 2020 due to the coronavirus pandemic, this year.

But the CEO of Galp, which has a 10% stake in the consortium, told Reuters on Monday his company did not include investments in Rovuma's onshore facilities in its net capital expenditure plan for the next five years.

"It means that at the moment it's very hard for us to predict when the time to invest will be," Brown said.

"Last year we were really planning to have built Rovuma by 2025 and I don't want to make a promise on Rovuma and then disappoint the market again," he said.

Exxon did not immediately respond to a request for comment and the other major partner, Italy's ENI, declined to comment.

"Before Galp starts investing in the project, the government needs to work with the local population to create the right kind of stability and social cohesion, as well as security, on the ground ... That may take a while," Brown said.

Brown said that once France's TotalEnergies, which stopped construction of a separate LNG project near Rovuma due to the latest attacks in March and is working with Mozambique to ensure stability in the area, has reliably resumed the works, "we will be in a position to consider our own project".

Despite the setbacks, Mozambique with its attractive gas projects is "a really important country for Galp", Brown said, and the consortium is "working to get the cost to a level where this project is really competitive".

Brown said that over the next five years, Brazil will absorb "the vast majority" of the 320 million to 400 million euros of net capex which Galp has allocated to upstream annually, while there will be "some investment in floating LNG in Mozambique and some small investments in Angola".

The investments in Brazil will be "mostly allocated to already sanctioned developments, including the Bacalhau I", he said.

Reporting by Sergio Goncalves; additional reporting by Stephen Jewkes and Jennifer Hiller; editing by Andrei Khalip and Jason Neely

Further high-potential optionality

exploring 2025+ opportunities

Area 4 | Rovuma LNG (Mozambique)

One of the most competitive LNG projects worldwide

Pre-FID activities focused on cost and concept optimisation

Exploring synergies with Area 1

Local security key to unlock development

First gas expected during 2H of the decade

Exploration activities

Delivering selected high-potential wells

Block 6 (São Tomé and Príncipe)

Prospective wildcat well to be spud in 2021

C-M-791 (Brazil)

Pre-salt potential play

Well to be spud in 2021/22

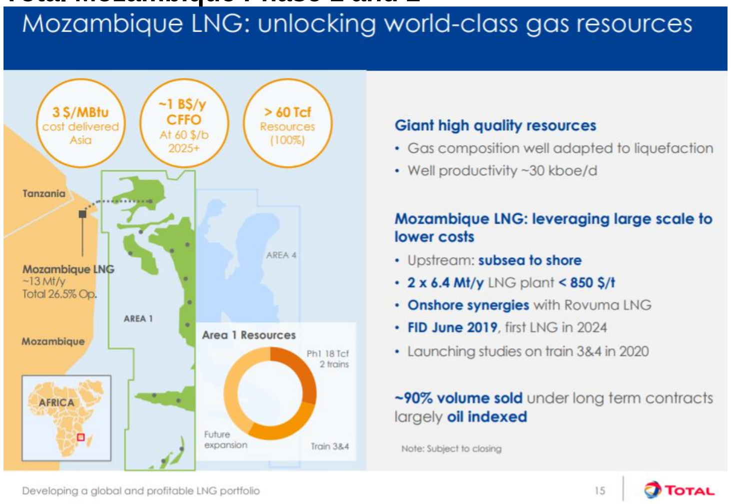
Multiple Brownfield LNG FIDs Now Needed To Fill New LNG Supply Gap From Mozambique Chaos? How About LNG Canada Phase 2?

Posted Wednesday April 28, 2021. 9:00 MT

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

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

Total Mozambique Phase 1 and 2



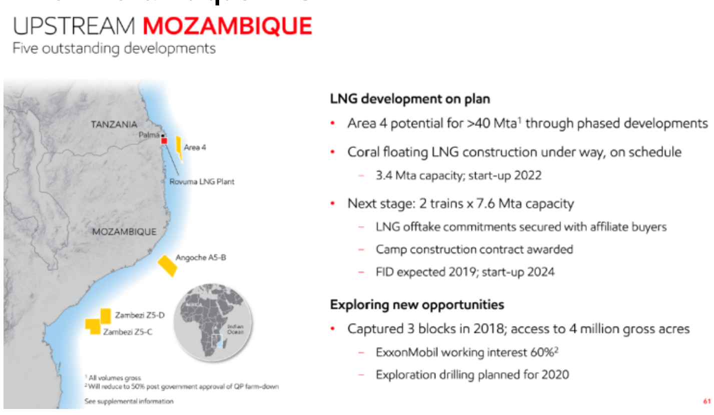
Source: Total Investor Day September 24, 2019

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

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

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

Exxon Mozambique LNG



Source: Exxon Investor Day March 6, 2019

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

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

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

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

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

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

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

Source: IEA

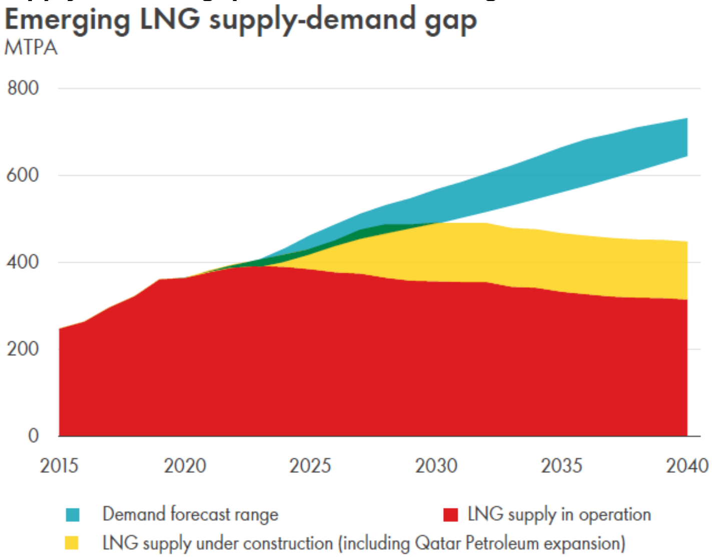
On Track   More Efforts Needed   Not on Track

Source: IEA Tracking Clean Energy Progress, June 2020

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

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

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



Source: Shell LNG Outlook 2021, Feb 25, 2021

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

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

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

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

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

https://www.thehindubusinessline.com/companies/lngs-share-of-indian-gas-demand-to-rise-to-70-by-2030-petronet-ceo/article34845886.ece

LNG's share of Indian gas demand to rise to 70% by 2030: Petronet CEO

Reuters NEW DELHI | Updated on June 18, 2021

Replacing about 30% of the country's crude oil imports with LNG would save $10 billion at current global oil price of $74/barrel, he said

The share of liquefied natural gas (LNG) in India's gas consumption could rise to 70% from the current 50% in 10 years, and new import terminals are needed, the chief executive of the country's top gas importer said.

Prime Minister Narendra Modi has set a target to raise the share of natural gas in the country's energy mix to 15% by 2030 from the current 6.3% to cut its carbon footprint.

To meet that target India's gas consumption needs to rise to 640 million standard cubic metres a day (mmscmd) from the current 155 mmscmd, AK Singh, chief executive of Petronet LNG, said at ET Energy Leadership summit.

Huge invesments by Indian cos

Indian companies are investing billions of dollars to strengthen gas infrastructure, including laying 15,000-kilometer pipelines to supply cleaner fuel to households and industries. India currently has 17,000 kms of gas pipeline network.

Also, LNG projects of 19 million tonnes per annum (mtpa) capacity are under construction and plans are afoot to increase use of LNG in trucks and buses.

"With limited increase in domestic gas supply LNG will play a major role in catering to this incremental demand and share of LNG in natural gas consumption is likely to increase from the present 55% to 70% in coming 9-10 years," Singh said.

Petronet operates two LNG terminals in India accounting for about 53% of the nation's existing 42.5 mtpa import capacity.

Singh said India needed to increase its LNG import capacity to 155 mtpa "considering 80% utilisation" to boost use of the cleaner fuel.

India imports about 85% of its oil needs. He said replacing about 30% of the country's crude oil imports with LNG would save $10 billion at current global oil price of $74/barrel.

Published on June 18, 2021

Finally, Some Visibility That India Is Moving Towards Its Target For Natural Gas To Be 15% Of Its Energy Mix By 2030

Posted: Wednesday October 23, 2019. 3:45pm MT

It's taking longer than expected, but we are finally getting visibility that India is investing significantly towards its goal to have natural gas be 15% of its energy mix by 2030. Earlier in Oct, India Oil Minister Dharmendra Pradhan said that there are $60 billion of natural gas infrastructure and LNG import terminals that are "under execution". He said "*I am not talking about potential investment. This number relates to the project that are under execution".* Natural gas consumption in India is only now back to 2011 levels at 5.6 bcf/d and represents only 6.2% of its energy mix. If India hits its 15% target of its energy mix by 2030, it would add natural gas demand, on average, of >1.5 bcf/d per year. At the same time India's domestic natural gas production peaked in 2010 at 4.6 bcf/d, but has been flat from 2014 thru 2018 at ~2.7 bcf/d, which means the big winner will be LNG. The most important factor driving this expectation for natural gas consumption growth is likely price. Asian LNG landed prices are down about 50% YoY and, more significantly, the expectation is for future Asian LNG prices to be at lower levels than prior cycles. India, by itself, may not be a LNG global game changer, but it is another positive support for why we believe LNG markets will rebalance sooner than expected ie. in 2022/2023. We see mid term Asian LNG landed prices lower than prior cycles in a rebalanced market (ie. +/- $8), which means that low capital costs will be critical for future LNG projects. We believe that BC's LNG key potential projects (LNG Canada Phase 2 and Chevron Kitimat LNG) can compete in this price environment as they have the potential for brownfield capital costs if they move to a continuous construction cycle following in lockstep to LNG Canada Phase 1, much like Cheniere does for its LNG projects in the Gulf Coast.

India has a pollution crisis. We don't think it is unfair to say India has a pollution crisis. In every pollution ranking, India has several cities among the most polluted cities. The 2018 World Air Quality Report (AirVisual) list of the World's Most Polluted Cities 2018 has 20 of the world's 25 most polluted cities being in India. India has all of the top 25 most polluted cities other than #3 Faisalabad (Pakistan), #7 Hotan (China), #10 Lahore (Pakistan), #17 Dhaka (Bangladesh), and #19 Kashgar (China). Like us, many people have been to Beijing on business and believe Beijing's reputation as a very polluted city is deserved. But to put in perspective, Beijing's ranking isn't even close to the 15 most polluted cities in China, let alone the world. Beijing's score on their scale is 50.9 vs the other Chinese cities #7in the world, Hotan at 116.0, and #19 Kashgar at 95.7, and the world's most polluted city #1 Gurugram (India) at 135.8 .

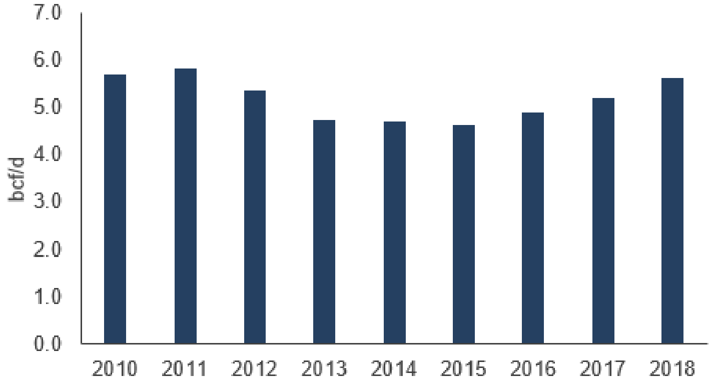
World's Most Polluted Cities 2018

Rank	City	Country	Rank	City	Country
1	Gurugram	India	14	Varanasi	India
2	Ghaziabad	India	15	Moradabad	India
3	Faisalabad	Pakistan	16	Agra	India
4	Faridabad	India	17	Dhaka	Bangladesh
5	Bhiwadi	India	18	Gaya	India
6	Noida	India	19	Kashgar	China
7	Patna	India	20	Jind	India
8	Hotan	China	21	Kanpur	India
9	Lucknow	India	22	Singrauli	India
10	Lahore	Pakistan	23	Kolkata	India
11	Delhi	India	24	Pali	India
12	Jodhpur	India	25	Rohtak	India
13	Muzaffarpur	India	26	Mandi Gobindgarh	India

Source: Airvisual

India natural gas consumption is only now back to 2011 levels. For the past couple years, we have been highlighting that the growth in India's natural gas consumption (and linked LNG imports) has been very low due to the slow buildout of domestic natural gas infrastructure and LNG import facilities. BP data shows India's natural gas consumption was 5.6 bcf/d in 2018, and this compares to its peak of 5.8 bcf/d in 2011. To put in perspective, China's natural gas consumption in 2011 was 13.1 bcf/d and reached 27.4 bcf/d in 2018.

India's Natural Gas Consumption (bcf/d)



Source: BP

Perhaps the best reason why there is better visibility – LNG prices are expected lower than prior cycles. A key reason for this lack of growth has been the price of LNG relative to coal. Our June 17, 2018 Energy Tidbits [LINK] highlighted comments from the Q&A from BP's Chief Economist speech "*Energy in 2017: two steps forward, one step back*" on this relative cost concept. We then wrote on the BP Chief Economist comments from an India company on why there isn't more natural gas and why coal is still going up. He said that the Indian executive said it was because the cost of natural gas was significantly more expensive than domestic coal and that the push in India is to get more power to more poorer people, but if natural gas is significantly higher, it can't be done, they have to rely on coal. What has happened since the BP Chief Economist June 2018 comment is that Asian LNG prices are down 50% and the expectation going forward is that future LNG prices are not expected to be at prior cycle highs. But the other question is what does it mean for LNG prices. There is an increasing supply of reasonable priced LNG around the world, whether it from Qatar, Papua New Guinea, the Gulf of Mexico and even Canada. And each of these areas has anchor projects to support future brownfield development. Couple that with increasing linkage of LNG prices away from oil indexed contracts, we believe this means that a balanced LNG market going forward is going is not going to see sustained high Asian LNG prices from prior cycles, but around more costs related more to lower LNG supply basins ie. LNG prices around mid to long term +/- $8 landed Asian LNG prices, and not the prior $10 - $12 range. As the BP Chief Economist highlights, price is a huge issue for India and it is likely that the expectation for lower LNG prices than prior cycles is the most important reason to push India to increased natural gas consumption.

Japan/Korea Marker (JKM) LNG Price

Source: Bloomberg

India is now getting serious about increasing natural gas consumption, has $60b of projects under execution. We follow the key India news as part of our weekly news scan for our Energy Tidbits memos and there is no question that the India government and its people realize they have to deal with this increasing pollution problem. And perhaps most of all, India is now taking specific, significant action to set the stage for increasing natural gas consumption and LNG imports. Earlier in Oct, Japan Times picked up a Reuters story "*India investing $60 billion on gas grid to link up nation by 2024*" [LINK]. The story notes "*India, one of the world's largest consumers of oil and coal, is investing $60 billion to build a national gas grid and import terminals by 2024 in a bid to cut its carbon emissions, the oil minister said on Sunday. India has struggled to boost its use of gas, which produces less greenhouse gas emissions than coal and oil, because many industries and towns are not linked to the gas pipeline network. Gas consumption growth was running at 11 percent in 2010 but growth slid to just 2.5 percent in the financial year 2018/19*." The most significant part of this story is that this is $60 billion of projects under execution, not planned or potential projects. The story quotes Oil Minister Dharmendra Pradhan "*I am not talking about potential investment. This number relates to the project that are under execution*". The critical natural gas infrastructure requirement is a domestic natural gas pipeline network to deliver gas throughout India. The India Ministry of Petroleum & Natural Gas Oct 3, 2019 release [LINK] said "*On the issue of moving towards the gas economy, Shri Pradhan said that over 16,000 km of gas pipeline has been built and an additional 11,000 km is under construction. With the tenth bid round for City Gas Distribution completed, it will cover over 400 districts and will extend coverage to 70 percent of our population".* Progress is being made. Plus LNG regasification projects continue to be completed. Below is our updated table of India LNG projects that are estimated to come on stream in 2019 and 2020. We haven't included the projects beyond 2020, but there are several planned projects already on the books.

India Current/Planned LNG Regasification Projects Est. In Service In 2019/2020

	State	Coast	Operator	Capacity (mtpa)	Capacity (bcf/d)	Expected Timelines
Existing Terminals						
Dahej	Gujarat	West	Petronet LNG	10.00	1.32	Operating
Dahej Phase 2	Gujarat	West	Petronet LNG	5.00	0.66	Operating
Hazira	Gujarat	West	Shell	5.00	0.66	Operating
Dabhol RGPPL	Maharashtra	West	GAIL & NTPC JV	5.00	0.66	Operating
Kochi	Kerela	West	Petronet LNG	5.00	0.66	Operating
Ennore Phase 1	Tamil Nadu	East	IOCL	5.00	0.66	Operating
Total Existing				**35.00**	**4.61**	
Upcoming Terminals						
Mundra	Gujarat	West	Adani & GSPC	5.00	0.66	2019
Jaigarh	Maharashtra	West	H-Energy Gateway Pvt. Limited	4.00	0.53	2019
Dahej Phase 3	Gujarat	West	PLL	2.50	0.33	2019
Mundra	Gujarat	West	Adani	5.00	0.66	2020
Digha FSRU	Odisha	East	H-Energy	4.00	0.53	2020
Ennore Phase 2	Tamil Nadu	East	IOCL	1.75	0.23	2020
Jafrabad	Gujarat	West	Swan Energy	5.00	0.66	2020
Total Upcoming				**27.25**	**3.59**	

Source: Bloomberg, Company Reports, Street Reports

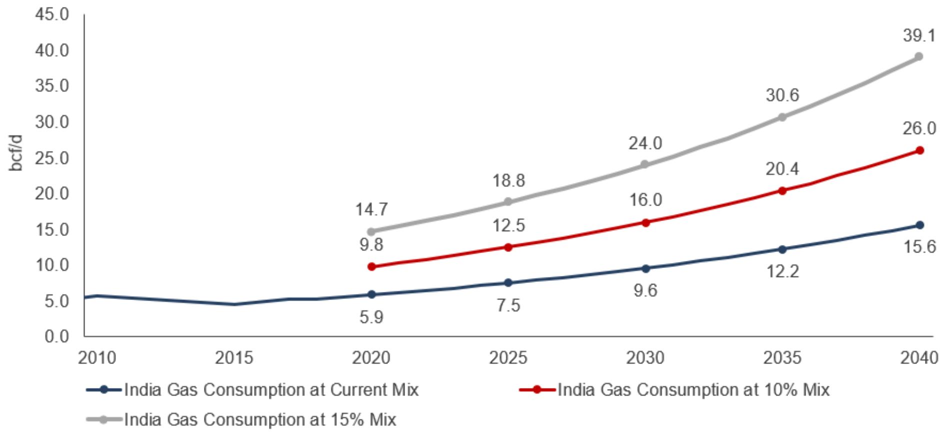
It reminds us of when China got really serious about natural gas in 2018. We should be clear that we do not consider India anywhere near as significant to global LNG markets as China. But conceptually, India getting serious about increasing natural gas consumption reminds us of what we were seeing in China in 2016/2017. India is probably more like China in 2016 as opposed to the summer of 2017, when it seemed clear that China was on the cusp of a major push in natural gas consumption and LNG would be the winner in 2018. India's impact should start to play out by year end 2020 as opposed to this winter. We first outlined the China LNG thesis in our Sept 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]. Our Sept 20, 2017 blog wrote "*The news flow from China this summer on its increasing fight and urgency to fight pollution supports China's plan to increase natural gas to 10% of its energy mix in 2020 and 15% of its energy mix in 2030. This is a game changer to global natural gas markets and, by itself, can bring LNG to undersupply 2 to 3 years earlier than expected. China's natural gas consumption increased by ~15% per year from 2005 thru 2016 and ~1.5 bcf/d per year vs China's 8.5%*

growth rate in energy in total. Yet natural gas only got to 5.9% of China's energy mix. If China is to hit 10% by 2020, it will need to increase natural gas consumption by 4 to 5 bcf/d per year. Assuming China continues to grow its domestic natural gas production by 0.6 bcf/d per year (its growth rate for last five years), China will need to import an additional ~3.5 to ~4.5 bcf/d per year. This is "per year"! And if so, we believe BC LNG will be back and there is a higher probability than ever before for a Shell FID on its BC LNG project in 2018." As it turned out, Shell did FID its LNG Canada project on Oct 1, 2018.

Natural gas is only 6.2% of India's energy mix vs its target of 15% in 2030. India, similar to China, has a target to have natural gas to be 15% of its total energy mix by 2030. This is not a new target, rather it has been in place and we first highlighted India's 15% target of its energy mix in our Nov 23, 2018 blog "*"India's Natural Gas Consumption Would Be Up ~1.3 Bcf/D Per Year If Its To Reach Its Target Of 15% Of Its Energy Mix By 2030*" [LINK] At that time, we noted some specific steps that were happening in 2019 and 2020 to put them on that long term plan. The impact to get to 15% of energy mix is significant to world LNG markets. This is a big increase from natural gas being 6.2% of India's energy mix in 2018. To put in perspective, in 2018, natural gas was 30.5% of US energy mix, 21.9% of Japan's energy mix, 16.0% of South Korea's energy mix, and 7.4% of China's energy. Note, China is up from 6.6% in 2017.

Hitting 15% of its energy mix would increase India's natural gas consumption by >1.5 bcf/d per year. We projected how much India's natural gas consumption would increase if it can hit its target of 15% of total energy mix in 2030. BP data shows India's natural gas consumption in 2018 was 5.6 bcf/d and natural gas was only 6.2% of total energy mix. BP also estimates India's total energy consumption grew at a rate of 5.2% per year for the 2007 – 2017 period, but energy consumption growth increased to +7.9% in 2018 YoY vs 2017 But if we only assume a 5% growth in total energy mix to 2030, then if natural gas is 15% of India's energy mix, it would be 18.8 bcf/d in 2025 and 24.0 bcf/d in 2030 ie. growth of +13.2 bcf/d to 2025 and +18.4 bcf/d to 2030. India's domestic natural gas production peaked in 2010 at 4.6 bcf/d, but has been flat from 2014 thru 2018 at +/- 2.7 bcf/d. We expect there to be some increased focus to at least return India to modest domestic natural gas production. But, until then, any growth in natural gas consumption will be met with LNG. Our model forecasts of >1.5 bcf/d per year, on average, in consumption is the equivalent of 2.5 Cheniere LNG trains per year.

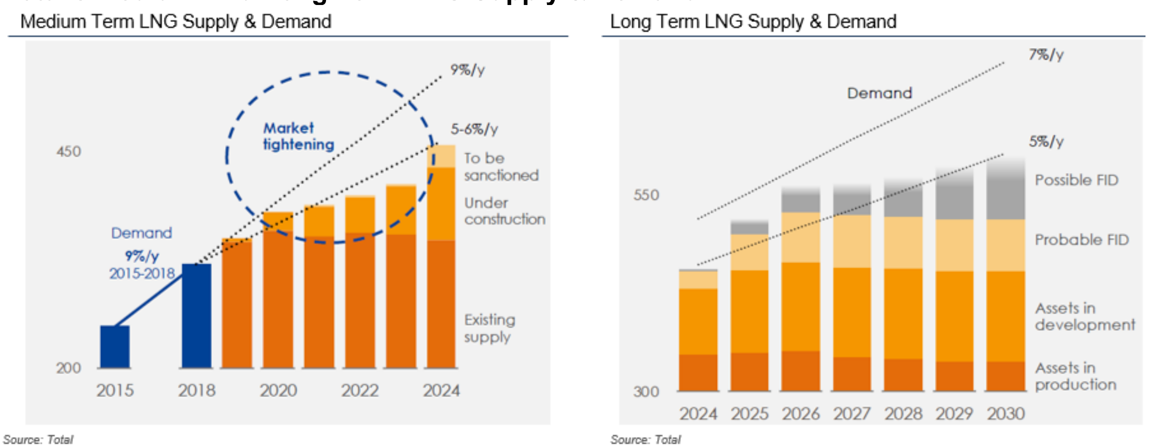
India's Projected Natural Gas Consumption @15% Of Energy Mix (bcf/d)



Source: BP, SAF

India may not be a LNG global game changer by itself like China, but does support the call that LNG markets rebalance sooner than expected. We had our SAF Group 2020 Energy Market Outlook on Monday Oct 7. A replay of the call and the supporting slide presentation are available on our website at [LINK]. Two of our key off consensus calls were on LNG including our view LNG market would balance earlier than expected ie. 2022/2023. We noted that we agree with markets that LNG will be oversupplied thru 2021, but where we disagree is that we see LNG markets balancing in 2022 or 2023. Our presentation reminded that LNG supply capacity needs to be in excess of demand to provide for turnarounds and allowance such that suppliers can deliver contract volumes. We also expect the required over capacity of supply is increasing as contract mix shifts away from historical oil indexed take or pay contracts with destination clauses to an increase share of portfolio contracts. There is no firm number, but we believe the required excess supply capacity relative to demand has increased from approx. 5% to 10% to +/-15% ie. LNG markets are effectively balanced when LNG supply capacity is >10% of demand. As a result, we believe that LNG markets rebalance in 2022/2023, a view which is similar to Total's Sept 25, 2019 Investor Day [LINK] (see below graphs). We should note that our view of balanced LNG markets doesn't mean a return to $12 or more Asian landed LNG prices, rather, we see the emergence of anchor LNG projects in areas with brownfield expansion potential means that a planning case for mid term Asian LNG price is in the $8 range. Our outlook presentation also includes our view that BC's LNG key potential projects (LNG Canada Phase 2 and Chevron Kitimat LNG) can compete in this price environment as they have the potential for brownfield capital costs if they move to a continuous construction cycle following in lockstep to LNG Canada Phase 1, much like Cheniere does for its LNG projects in the Gulf Coast. Our outlook call did not specifically work in the India Energy Minister's comment on in execution projects, but, if anything, it provides us with more confidence for the call for LNG markets to rebalance in 2022/2023.

Total's Medium And Long Term LNG Supply & Demand



Source: Total Sept 25, 2019 Investor Day

Director's Cut
April 2021 Production

Oil Production

March	34,376,074 barrels = 1,108,906 barrels/day (final)
April	33,646,529 barrels = 1,121,551 barrels/day (all-time high 1,519,037 BOPD Nov 2019)
	1,080,263 barrels/day or 96% from Bakken and Three Forks
	41,288 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
March	54.38	59.05	56.19
April	55.35	63.15	56.82
May	58.28	62.65	60.41
Today	62.75	70.91	66.83
All-time high (6/2008)	$125.62	$134.02	$126.75
Revised Revenue Forecast			**= $50.00**

Gas Production & Capture

March Production	89,074,463 MCF = 2,873,370 MCF/day
Gas Captured: 94%	83,380,571 MCF = 2,689,696 MCF/day
April Production	88,898,778 MCF = 2,963,293 MCF/day (all-time high 3,145,172 MCFD Nov 2019)
Gas Captured: 93%	Capture 82,821,828 MCF = 2,760,728 MCF/day (all-time high 2,899,998 MCFD Mar 2020)

Rig Count

March	15
April	15
May	19
Today	20
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

	March	April	May	Revised Revenue Forecast
Permitted	55 drilling 0 seismic	51 drilling 0 seismic	46 drilling 0 seismic (All-time high was 370 – Oct. 2012)	-
Completed	43 (Final)	31 (Revised)	41 (Preliminary)	**30→40→50→60**
Inactive[2]	2,351	2,088	-	-
Waiting on Completion[3]	628	731	-	-
Producing	16,212	16,374 (Preliminary) (NEW all-time high 16,374 in April 2021) *14,212 (87%) from unconventional Bakken – Three Forks* *2,162 (13%) from legacy conventional pools*	-	-

Fort Berthold Reservation Activity

	Total	Fee Land	Trust Land
Oil Production (barrels/day)	275,279	111,704	163,575
Drilling Rigs	4	1	3
Active Wells	2,557	641	1,916
Waiting on completion	97		
Approved Drilling Permits	244	31	213
Potential Future Wells	3,995	1,123	2,872

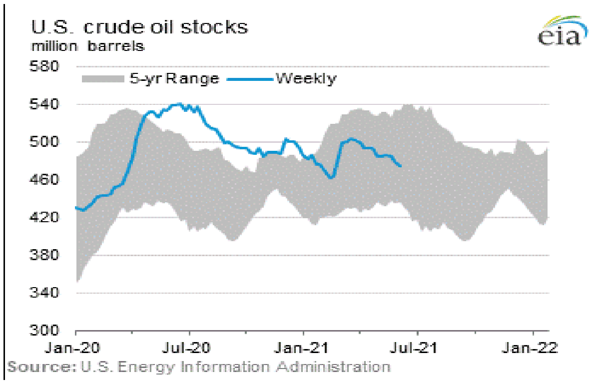
Drilling and Completions Activity & Crude Oil Markets

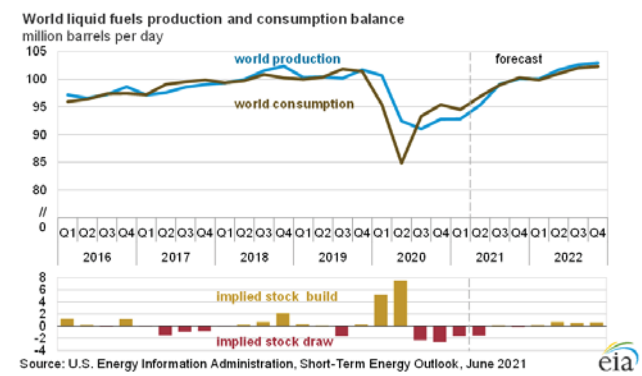
The drilling rig count was stable in the mid 50's second half of 2019 through April 2020. Drilling rig count fell 65% from January 2020 to April 2021.

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 April and to 9 today.

At their June 2021 meeting OPEC+ agreed to stick to the plan approved in April to raise output 350,000 barrels day in June, and then 440,000 barrels per day in July. Liquid fuel demand bottomed out in August and is recovering slowly but unevenly (gasoline +2%, distillate -3%, jet fuel -26%). 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 it now appears DAPL will continue normal operations through March 2022.

Drilling activity is slowly increasing but remains volatile due to oil price uncertainty. Operators continue to maintain a permit inventory of approximately 12 months.

Gas Capture

US natural gas storage is now 2% below the five-year average. Crude oil inventories are back to normal in the US, but world storage is 75 million barrels 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 more normal $2.54/MCF today. This results in a current oil to gas price ratio of 26 to 1. The state wide gas flared volume from March to April increased 18,892 MCFD to 202,566 MCF per day, and the percent flared increased to 6.8% while Bakken capture percentage remained at 94%.

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

Gas Capture Details:

Statewide..................	93%
Statewide Bakken.........	94%
Non-FBIR Bakken........	94%
FBIR Bakken.............	90%
Trust FBIR Bakken...	91%
Fee FBIR...............	81%

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.

BLM published a new final rule 43 CFR Parts 3100, 3160 and 3170 to update and replace its regulations on venting and flaring of natural gas effective 1/17/16. The final rule can be viewed online at https://www.blm.gov/programs/energy-and-minerals/oil-and-gas/operations-and-production/methane-and-waste-prevention-rule. North Dakota, Wyoming, Montana, Western Energy Alliance, and IPAA filed for a preliminary injunction to prevent the rule going into effect until the case is settled. A hearing in Casper, Wyoming was held 1/6/17. On 1/16/17 the court denied all of the petitioners’ motions for preliminary injunctions. **On 2/3/17 the US House of Representatives voted 221-191 to approve a Congressional Review Act resolution against the rule.** On 3/28/17 President Trump issued an executive order which in part directs “The Secretary of the Interior shall review the following final rules, and any rules and guidance issued pursuant to them, for consistency with the policy set forth in section 1 of this order and, if appropriate, shall, as soon as practicable, suspend, revise, or rescind the guidance, or publish for notice and comment https://bismarcktribune.com/news/state-and-regional/north-dakotas-status-as-nations-2nd-biggest-oil-producer-in-jeopardy/article_1453c3dc-a9d4-5d74-93b6-5f002a28c6f2.html

North Dakota's status as nation's 2nd-biggest oil producer in jeopardy

AMY R. SISK - Jun 14, 2021

North Dakota has ranked as the nation's second-biggest oil producer for nine years, but it's on the verge of losing that status as oil production soars in New Mexico.

By one account, North Dakota has already fallen into third place.

"It's a horse race," said Lynn Helms, North Dakota's mineral resources director.

Texas continues to lead the nation in oil production. The Permian Basin spans parts of New Mexico and Texas, and it's arguably the biggest competition for North Dakota's Bakken oil patch. The southern oil-producing region is situated closer to major refineries and export terminals than the Bakken, and it attracts significant drilling and investment within the oil and gas industry.

The U.S. Energy Information Administration on Monday reported that New Mexico produced 1.16 million barrels of oil per day in March, the most recent month for which data is available from all states. North Dakota's daily oil output that month was 1.11 million barrels per day, according to data from the state Oil and Gas Division.

But the figure reported by the federal government for New Mexico differs from what that state's own regulators say. A state agency there put New Mexico's output at 1.05 million barrels per day.

It's unclear what accounts for the discrepancy. North Dakota officials say they believe the federal government takes into account estimates in its numbers. Either way, the two states' oil outputs are neck and neck.

"At the rate that they're growing production, they're going to pass us unless our pace picks up," Helms said.

A state's high ranking gives it bragging rights, but its position also holds other implications. Rankings can affect an oil company's ability to find investors to fund a project in a state, Helms said. And North Dakota's ranking matters when the state seeks to "flex its muscle" with federal agencies on issues such as methane emissions rules and oil leasing on public lands, he said.

North Dakota became the nation's second-biggest oil producer early on in the Bakken oil boom as horizontal drilling and fracking technology sent North Dakota's oil production skyrocketing. The state surpassed Alaska to take the spot in 2012.

Latest data

Oil and gas production information tends to lag several months, and North Dakota's Oil and Gas Division released figures for April oil production on Monday. The state's daily oil output grew 1.1% over March to 1.12 million barrels. A record 16,374 oil wells are active in the state.

The number of wells that have been drilled but not yet fracked grew, and none of those wells are pumping oil yet. Fracking involves injecting water, sand and chemicals down a well at a high pressure to crack open rock and release oil, a necessary step before a Bakken well can start producing oil. Helms said more fracking could occur as spring road restrictions are lifted, potentially boosting the state's oil production.

North Dakota's gas production grew 3.1% in April. The state is the nation's 12th-biggest gas producer.

The state aims to capture gas produced alongside oil at wells to prevent it from being wastefully burned off. With 93% of gas produced statewide captured in April, North Dakota met its target of capturing at least 91%.

Gas produced on the Fort Berthold Indian Reservation fell just outside the target at 90%.

The state will need more natural gas processing facilities if it's to continue to meet its flaring target in future years, North Dakota Pipeline Authority Director Justin Kringstad said. Several companies are looking at expanding existing processing plants or building new ones.

WBI Energy recently received a key federal permit for a pipeline that would begin near Tioga and end near Watford City. The project would help bring more gas processing to the area north of Lake Sakakawea, a region in need of more of that sort of infrastructure, Kringstad said.

MONTHLY UPDATE

APRIL 2021 PRODUCTION & TRANSPORTATION

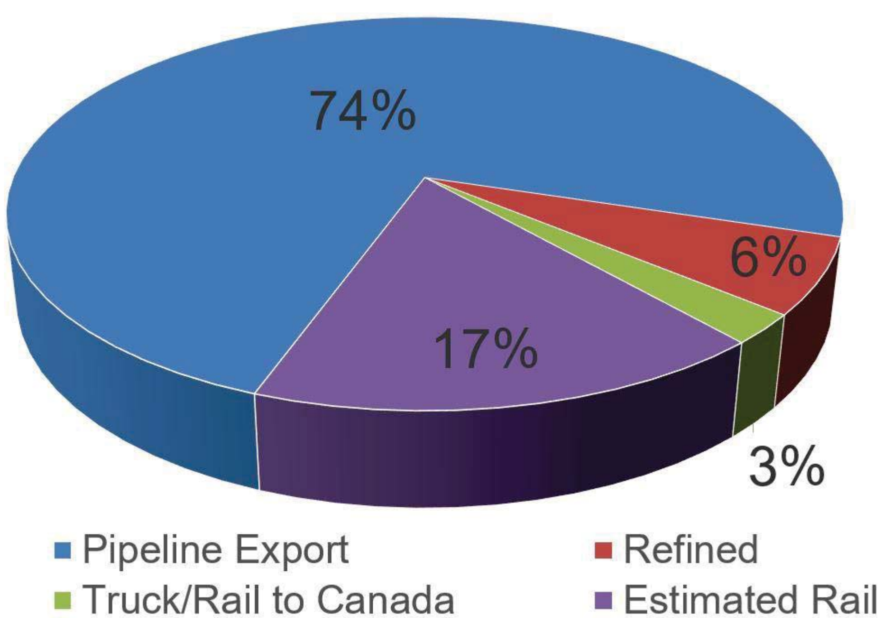
North Dakota Oil Production

Month	Monthly Total, BBL	Average, BOPD
Mar. 2021 - Final	34,376,074	1,108,906
Apr. 2021 - Prelim.	33,646,529	1,121,551

North Dakota Natural Gas Production

Month	Monthly Total, MCF	Average, MCFD
Mar. 2021 - Final	89,074,463	2,873,370
Apr. 2021 - Prelim.	88,898,778	2,963,293

Estimated Williston Basin Oil Transportation, Apr. 2021



CURRENT DRILLING ACTIVITY:

NORTH DAKOTA[1]

19 Rigs

EASTERN MONTANA[2]

0 Rigs

SOUTH DAKOTA[2]

0 Rigs

SOURCE (JUNE 14, 2021):

1. ND Oil & Gas Division
2. Baker Hughes

PRICES:

Crude (WTI): $70.89

Crude (Brent): $72.79

NYMEX Gas: $3.33

SOURCE: BLOOMBERG (JUNE 14, 2021)

GAS STATS*

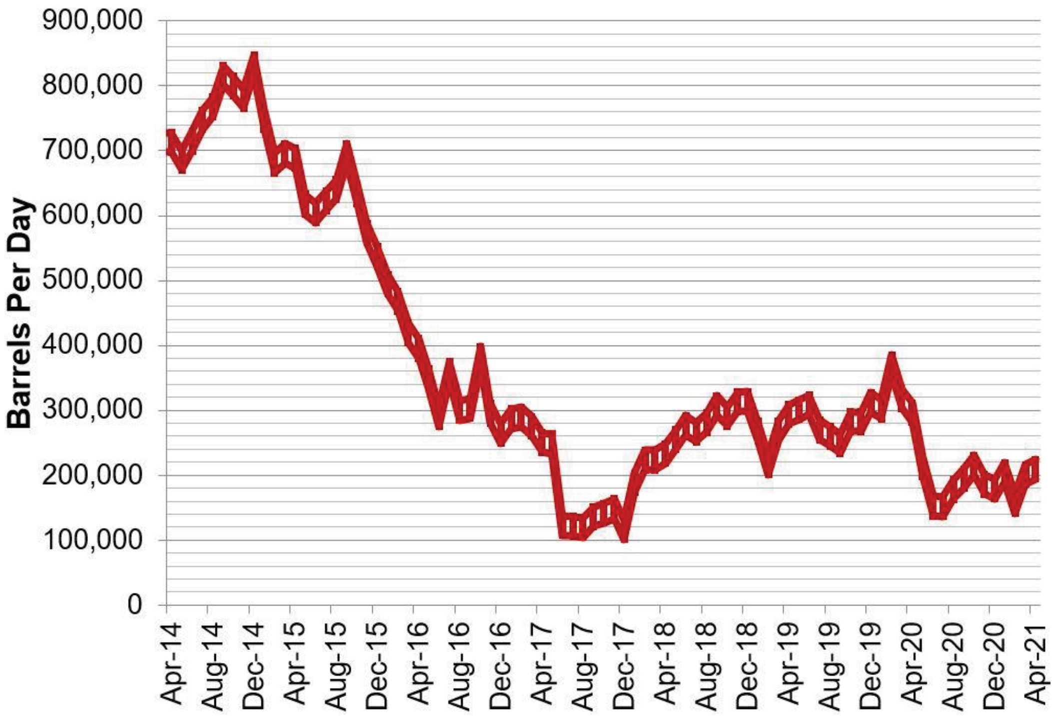
93% CAPTURED & SOLD

5% FLARED DUE TO CHALLENGES OR CONSTRAINTS ON EXISTING GATHERING SYSTEMS

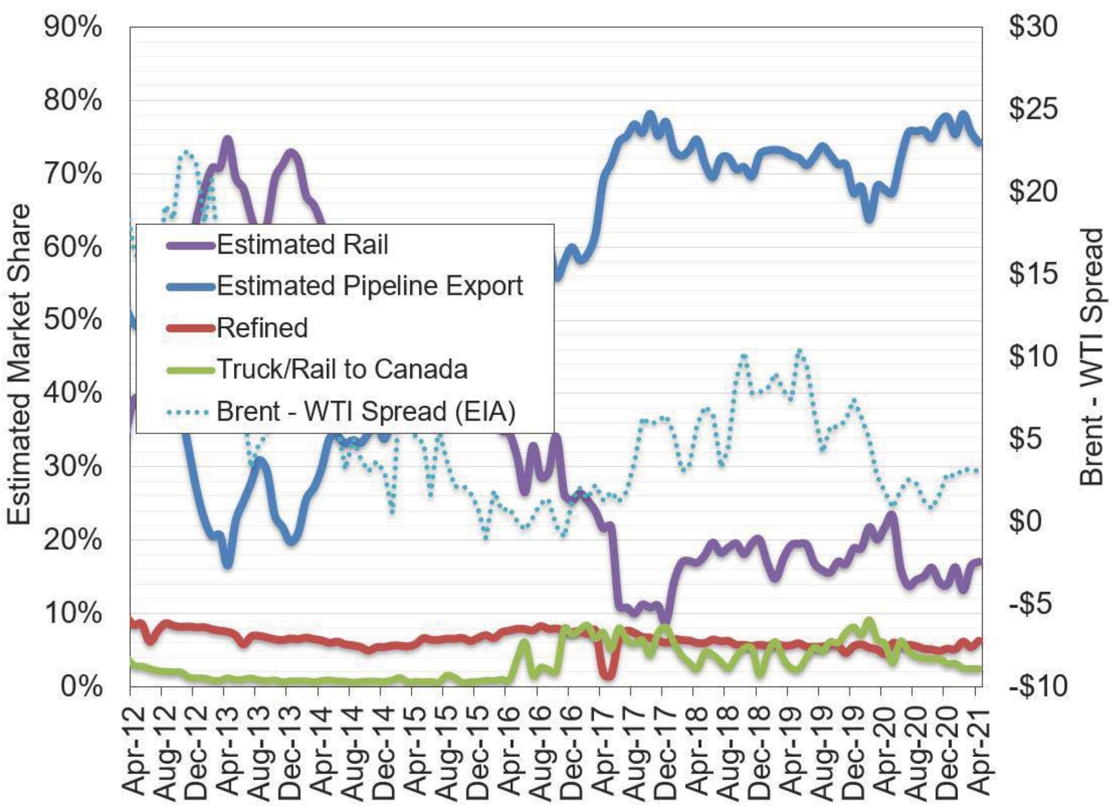
2% FLARED FROM WELL WITH ZERO SALES

APRIL 2021 NON-CONF DATA

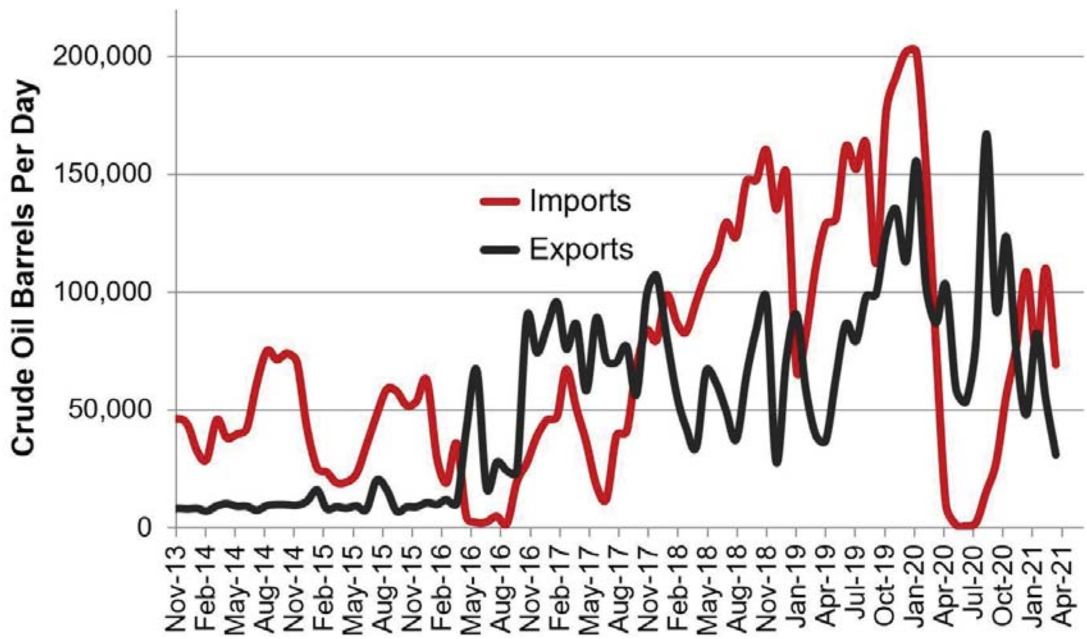
Estimated North Dakota Rail Export Volumes



Estimated Williston Basin Oil Transportation

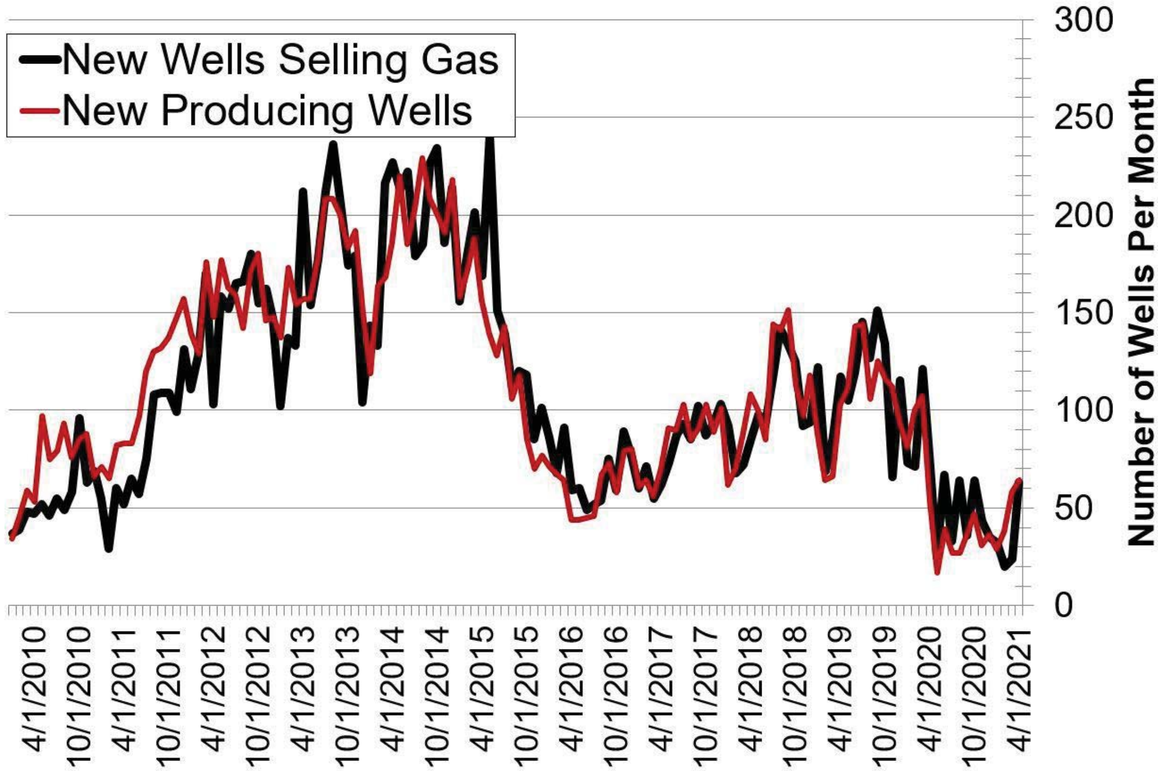


Williston Basin Truck/Rail Imports and Exports with Canada



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	47,771	2,829	1,134,157
March	1,108,906	48,233	2,744	1,159,883
April	1,121,551			
May				
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://www.npr.org/2021/06/15/1006948814/bidens-ban-on-new-oil-and-gas-leases-is-blocked-by-a-federal-judge

Biden's Ban On New Oil And Gas Leases Is Blocked By A Federal Judge

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June 15, 20216:51 PM ET

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Louisiana Attorney General Jeff Landry, seen in 2019, led a lawsuit against the Biden administration's suspension of new oil and gas leases on federal land. A federal judge has ruled the leasing should resume.

Manuel Balce Ceneta/AP

NEW ORLEANS (AP) — The Biden administration's suspension of new oil and gas leases on federal land and water was blocked Tuesday by a federal judge in Louisiana, who ordered that plans be resumed for lease sales that were delayed for the Gulf of Mexico and Alaska.

U.S. District Judge Terry Doughty's ruling came in a lawsuit filed in March by Louisiana's Republican attorney general, Jeff Landry and officials in 12 other states. Doughty's ruling granting a preliminary injunction to those states said his order applies nationwide.

The 13 states said the administration bypassed comment periods and other bureaucratic steps required before such delays can be undertaken. Doughty heard arguments in the case last week in Lafayette.

The moratorium was imposed after Democratic President Joe Biden on Jan. 27 signed executive orders to fight climate change. The suit was filed in March. The states opposing the suspension said it was undertaken without the required comment periods and other bureaucratic steps.

Federal lawyers also argued that the public notice and comment period doesn't apply to the suspension, that the lease sales aren't required by law and that the Secretary of the Interior has broad discretion in leasing decisions.

Although Landry and the lawsuit's supporters said the moratorium has already driven up prices and endangered energy jobs, Biden's suspension didn't stop companies from drilling on existing leases.

"No existing lease has been cancelled as a result of any of the actions challenged here, and development activity from exploration through drilling and production has continued at similar levels as the preceding four years," lawyers for the administration argued in briefs.

A long-term halt to oil and gas sales would curb future production and could hurt states like Louisiana that are heavily dependent on the industry that has contributed to global warming.

The lawsuit notes that coastal states receive significant revenue from onshore and offshore oil and gas activity. Stopping leases, the lawsuit argues, would diminish revenue that pays for Louisiana efforts to restore coastal wetlands, raise energy costs and lead to major job losses in oil-producing states.

[LINK]

June 18, 20217:08 AM MDTLast Updated 5 hours ago

EXCLUSIVE OPEC told to expect limited U.S. oil output growth, for now - sources

Alex LawlerAhmad GhaddarDmitry Zhdannikov

- Summary
- Shale outlook discussed at Tuesday OPEC technical meeting
- U.S. output growth seen at about 200,000 bpd in 2021
- Capital discipline remains focus for shale companies, OPEC told
- OPEC meets to decide output policy on July 1

LONDON, June 18 (Reuters) - OPEC officials heard from industry experts that U.S. oil output growth will likely remain limited in 2021 despite rising prices, OPEC sources said, giving it more power to manage the market in the short term before a potentially strong rise in shale output in 2022.

Officials from OPEC's Economic Commission Board (ECB) and external presenters attended a meeting on Tuesday focused on U.S. output, the sources said. OPEC heard from more forecasters on the outlook for 2021 and 2022 at a separate meeting on Thursday.

While there was general agreement on limited U.S. supply growth this year, an industry source said for 2022 forecasts ranged from growth of 500,000 bpd to 1.3 million bpd.

"The general sentiment regarding shale was it will come back as prices go up but not super fast," said a source at one of the companies that provided forecasts to OPEC.

U.S. shale oil output usually responds rapidly to price signals and U.S. crude has this week hit its highest since October 2018 at nearly $73 a barrel. But U.S. producers are still focusing on capital discipline and investor returns, rather than expanding supply, the ECB heard.

"Investment discipline and free cash flow for the investor," said one OPEC+ source on condition of anonymity, summarising one of the ECB meeting's talking points. The ECB advises OPEC ministers and does not set policy.

Two sources said a presentation made to the meeting forecast U.S. output would rise by a low rate of 200,000 barrels per day this year. A third source said this level of growth was the consensus for this year among most presentations.

The lack of a large shale rebound could make it easier for OPEC and its allies, known as OPEC+, to manage the market. OPEC+ is gradually unwinding record output curbs made last year as demand recovers, and meets to decide policy on July 1.

"It looks like the shale oil genie is going to stay in the bottle for now," said the source at one of the companies that provided forecasts. "OPEC and Saudi Arabia have a lot of power at this time."

MORE SHALE IN 2022

At Thursday's technical meeting, OPEC+ considered forecasts from a range of organisations, including the International Energy Agency, Argus Media, the U.S. Energy Information Administration, Wood MacKenzie, IHS, Energy Intelligence and Energy Aspects, sources said.

One of the OPEC sources said the forecasts were not projections OPEC was adopting and a fourth OPEC source said, while it was clear that capital discipline remained a priority for U.S. producers, the production outlook was not clear.

OPEC itself has been forecasting a limited shale rebound this year, as have U.S. producers themselves.

The latest OPEC forecast is for U.S. crude production in 2021 to decline by 120,000 bpd to 11.2 million bpd, and for output of tight crude - another term for shale - to drop by 140,000 bpd to 7.15 million bpd.

The group keeps a close watch on the outlook for U.S. supply. OPEC producers were sent reeling by a 2014-2016 price slide and global glut caused partly by rising U.S. output. In 2014, U.S. production rose by 1.5 million bpd.

Editing by Elaine Hardcastle

SAF Group created transcript of excerpt from Gulf Intelligence New Silk Road "Live" Podcast June 17, 2021 https://soundcloud.com/user-846530307/podcast-daily-energy-markets-forum-new-silk-road-live-june-17th

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

At 12:15 min mark.

Gulf Intelligence, Sean Evers Managing Partner. "*Matt, we touched nearly $75 a barrel yesterday, $74.96 was the high intraday trade. This market is trading on fundamentals as well. Ultimately, we saw a massive inventory draw over 7 million barrels, confirmed first by the API then by the EIA, the fundamentals are quite solid, OPEC still holding very tight reins*."

Matt Stanley, Director, Star Fuels (Dubai). "*yes, crude is drawing, stocks have been on a downward trajectory for awhile, but gasoline inventories are the highest since February. And if you want a bellweather for demand, lots of people will look at what's called the 3-2-1 crack in the US. That's 3 barrels of WTI in, 2 barrels of gasoline out and 1 diesel out. that's the lowest its been since February as well. That was trading $25 a barrel in May, its now trading just above $17. So yes, crude might be going places, but the same argument. Crude has to be burned and refined and consumed. In order for oil demand to look anything like the tangible, these forecasters, you know the second half rhetoric is all about demand is going to come roaring back. You look at real tangible data regarding demand and I can't see, I can't form that same argument for the second half rhetoric. You know his highness Sheik Maktoum, the chairman of Emirates Group on Tuesday, who's historically he's run a fantastic business for the last 30 years. the Emirates Group reported a $6 billion loss, wasn't surprising, most airlines have. But his outlook was not bullish. That hub and spoke model that Emirates have, is still in a perilous state. Of course, people are hoping that air travel is going to come back. I was talking to a friend last night, if you look at Asia and what's happening in Asia. China, Singapore, the {xxxx?] have got no interest in opening borders anytime soon. They are pursing this zero case agenda. That's completely up to them. But 5 million barrels of oil demand is still lacking from pre-pandemic. Half of that demand that is forecast to come back is jet fuel. So he told me, jet fuel demand into the EU is about 700,000 b/d. this year so far, its been about between 150 and 200. So I look at these data Sean and so yes, I see crude going places, I don't see the products that's being refined going anywhere close to what these forecasters are assuming its going."*

Sean Evers. "*Rustin pointed out yesterday that tanker rates are still way down and freight markets are not buying into yet there is a big wave of oil coming*"

Matt Stanley. "*boy, of course he's the one feeling the pinch because he works for one of the world's biggest shipping companies. So he's right. this is the irony. You've got more cargoes coming back with OPEC bringing back production and you've got a backwardated market, which out to on crude, I think its $3.60 until December. So if you put oil on a ship and store it as Vitol is doing off the coast of Southxxx in the UK at the moment, it doesn't make sense because the market is such strong backwardation that you can't cover that cost. So it doesn't ring true to me that freight being so weak because there's not as much demand for arbitrage cargos but flat prices where it was before the pandemic was even hinted at"*

Prepared by SAF Group http://www.safgroup.ca/insights/trends-in-the-market/

At 23:15 min mark.

Sean Evers: "do you think we could tip over that big $75 handle or are we retreating?"

Matt Stanley "*I just want to touch on what Dr. Carol said, which I thought she raised an excellent point you know, it's the same old argument that we are having. I would have liked to be in that virtual conference when Prince Abdulaziz. Didn't he tell them Not to Drill Baby Drill, to stop all their antics. And now what's he's saying, please get involved in the shale patch and start pumping oil. I mean I find it quite ironic as Carol said that they're sitting on all this idle production but they're encouraging others to invest in the oil producing sector as well. The market has relied on what OPEC have done. The rally is being triggered from supply curtailment. The demand rhetoric, again, I mention and Carol said as well, Q4/22 is when Trafigura and Vitol see it coming back, I agree with that. Igor Sechin as well, he's notorious bullish commentator and bullish guy. Vitol just bought I think 5% of the Vostok Western Siberia production. and he made a great point. Igor Sechin said the world consumes oil but no one wants to invest in it. and I think that's the reason, the reason behind the dreaded triple figure word, the $100 oil, is very much a possibility because the world relies on OPEC to keep prices elevated, it won't rely on them to keep them supressed. Do they say we are going to keep a cap on prices a maximum of $80 a barrel but we're not going to allow them below $60. All you're going to do is, based on what mr. sechin said, I think the breakeven is on that western Siberia field is $35 to $40 a barrel. Shale producers say its $60 a barrel, WTI is $71.75 right now. I think that what's going to happen is and marco [xxxx?] hinted at this. Covid has accelerated the renewable argument, you've got a big drive on that as well Sean, Gulf Intelligence, the hydrogen discussion, they are all discussions that we need to have. And the hedgers have been bought forward that the world won't rely on fossil fuels maybe in 30 years, there will be a renewable agenda, of course. But in the meantime, we all still need to drive our cars because we all haven't got Teslas. And we all need to fill them up somehow. And I think that you will see most of those traders get into the shale patch because the likes of Parsley or Cilantro or Oregano, whatever they're called, they are not getting into those fields. I think that its going to be left to the big traders because they have come out with some pretty punchy comments in the last few days. That's what I am keeping my eye on. I think its overall trader sentiment because the fossil fuel argument is now no longer something the Shells, BPs, Totals are really discussing*."

SAF Group created transcript of PM Trudeau post G7 press conference June 13, 2021.

At 49:00 min mark of CBC Rosemary Barton Live [LINK]

Question: "*COP-26 coming up as well, the oil sands/tar sands producers, they've got a plan to Net Zero by 2050, is that good enough, a lot of it is based on technology, which as of yet is unproven on a mass scale, sequestration as well. Do you Sir, does Canada need to be more ambitious?*"

Trudeau: "*Canada has put in place one of the strongest, broad based prices on pollution in the world. We know putting a price on pollution is one of the strongest ways not just to move forward on fighting climate change, but to incentivize business to make investments that decarbonize the workings of our economy. We also at the same time know that transforming our energy mix is going to be extremely important. that's why the energy expertise by workers across this country are going to be put forward in initiatives like a recent agreement we signed on hydrogen for example. Investing in critical minerals that will be essential for zero emissions vehicles of the future. when we talk of critical minerals, we know that china is right now a strong provider to the world of critical minerals. But Canada is a place where we have strong and stable supplies of that as well that could be of use in a reliable supply chain to the world. There are many many conversations we have on strengthening our environment and creating good jobs in the future and that involves being ambitious as we have been in setting not just ambitious targets for 2030 but showing a very clear plan on how we are going to reach those targets as well as being deeply committed to being net Zero by 2050, which is something actually we are working very hard to pass in the House of Commons in Canada right now. Hopefully we will see the necessary progressive parties come together to support that Net Zero legislation so Canada can continue to demonstrate real leadership in fighting climate change*".

https://www.newswire.ca/news-releases/canada-s-largest-oil-sands-producers-announce-unprecedented-alliance-to-achieve-net-zero-greenhouse-gas-emissions-866303015.html

Canada's largest oil sands producers announce unprecedented alliance to achieve net zero greenhouse gas emissions

Oil Sands
Pathways to Net Zero

NEWS PROVIDED BY **MEG Energy Corp.**
Jun 09, 2021, 06:45 ET

CALGARY, AB, June 9, 2021 /CNW/ - Canadian Natural Resources, Cenovus Energy, Imperial, MEG Energy and Suncor Energy formally announced today the Oil Sands Pathways to Net Zero initiative. These companies operate approximately 90% of Canada's oil sands production. The goal of this unique alliance, working collectively with the federal and Alberta governments, is to achieve net zero greenhouse gas (GHG) emissions from oil sands operations by 2050 to help Canada meet its climate goals, including its Paris Agreement commitments and 2050 net zero aspirations.

Canada's largest oil sands producers announce unprecedented alliance to achieve net zero greenhouse gas emissions (CNW Group/MEG Energy Corp.)

- This collaborative effort follows welcome announcements from the Government of Canada and the Government of Alberta of important support programs for emissions-reduction projects and infrastructure. Collaboration between industry and government will be critical to progressing the Oil Sands Pathways to Net Zero vision and achieving Canada's climate goals.
- The Pathways vision is anchored by a major Carbon Capture, Utilization and Storage (CCUS) trunkline connected to a carbon sequestration hub to enable multi-sector 'tie-in' projects for expanded emissions reductions. The proposed CCUS system is similar to the multi-billion dollar Longship/Northern Lights project in Norway as well as other CCUS projects in the Netherlands, U.K. and U.S., all of which involve significant collaboration between industry and government.
- The Pathways initiative is ambitious and will require significant investment on the part of both industry and government to advance the research and development of new and emerging technologies.
- The companies involved look forward to continuing to work with the federal and Alberta governments, and to engaging with local Indigenous communities in northern Alberta to make this ambitious, major emissions-reduction vision a reality so those communities can continue to benefit from Canadian resource development.

As proud Canadian companies, members of the Pathways alliance share the aspiration of Canadians to find realistic and workable solutions to the challenge of climate change. The oil sands industry is a significant source of GHG emissions and the initiative will develop an actionable approach to address those emissions, while also preserving the more than $3 trillion in estimated oil sands contribution to Canada's gross domestic product (GDP) over the next 30 years. The initiative will create jobs, accelerate development of the clean tech sector, provide benefits for multiple other sectors and help maintain Canadians' quality of life. The members of the Pathways alliance will do their part by making the economic investments needed to ensure that our companies successfully make the transition to a net zero world, and hence, deliver long-term value to shareholders.

Because there is no single solution to achieving net zero emissions, the initiative incorporates a number of parallel pathways to address GHG emissions, including:

- A core Alberta infrastructure corridor linking oil sands facilities in the Fort McMurray and Cold Lake regions to a carbon sequestration hub near Cold Lake via a CO_2 trunkline. The trunkline would also be available to other industries in the region interested in capturing and sequestering CO_2. There is also potential to link the infrastructure corridor to the Edmonton region.
- Deploying existing and emerging GHG reduction technologies at oil sands operations along the corridor, including CCUS technology, clean hydrogen, process improvements, energy efficiency, fuel switching and electrification.
- Evaluating, piloting and accelerating application of potential emerging emissions-reducing technologies including direct air capture, next-generation recovery technologies and small modular nuclear reactors.

In addition to collaborating and investing together with industry, it is essential for governments to develop enabling policies, fiscal programs and regulations to provide certainty for this type of long-term, large-scale investment. This includes dependable access to carbon sequestration rights, emissions reduction credits and ongoing investment tax credits. We look forward to continued collaboration with both the federal and Alberta governments to create the regulatory and policy certainty and fiscal framework needed to ensure the economic viability of this initiative.

Canada is uniquely positioned to be a global leader in responsible oil production. The country has the world's third-largest oil reserves, some of the most stringent regulations and standards governing energy projects anywhere in the world, a strong track record for technology development and an established reputation of industry working together with Indigenous communities and municipalities. Members of the Pathways initiative believe the most effective way to address climate change is by developing and advancing new technologies and that this unprecedented challenge can and will be solved by Canadian ingenuity, leadership and collaboration.

While alternative energy sources will play an increasingly important role in the decades ahead, all internationally recognized forecasts indicate fossil fuels will continue to be an essential requirement through 2050 and beyond as part of a diversified energy mix, including as a feedstock for carbon fibres, asphalt, plastics and other important products. That's why it's critical to take action now to ensure Canada takes its place as a leading supplier of responsibly produced oil to meet the world's demand for energy well into the future.

QUOTES:

Government of Alberta

"The Oil Sands Pathways to Net Zero initiative is an industry driven, made-in-Alberta solution which will strengthen our position as global ESG leaders," said Sonya Savage, Alberta's Minister of Energy. "Every credible energy forecast indicates that oil will be a major contributor to the energy mix in the decades ahead and even beyond 2050. Alberta is uniquely positioned and ready to meet that demand. This initiative will also pave the way for continued technological advancements, ultimately leading to the production of net zero barrels of oil."

Canadian Natural Resources Limited

"Canada has an opportunity to lead on climate change by delivering meaningful emissions reductions as well as balancing sustainable economic development," said Tim McKay, Canadian Natural President. "Canadian ingenuity has enabled oil sands development and with continued innovation, positions Canada to be the ESG-leading barrel to meet global energy demand. We are committed to working together with industry partners and governments to help meet Canada's climate objectives while providing sustainable long-term economic and social benefits for Canadians from the oil sands."

Cenovus Energy

"This collaborative effort amongst oil sands peers shows our serious commitment to global climate leadership," said Alex Pourbaix, Cenovus President and CEO. "We are doing more than just talking about the need to play a role – we are taking bold action to address our emissions challenge and earn our spot as the supplier of choice to meet the world's growing demand for energy."

Imperial

"Canada has what it takes to be the responsible energy provider to the world," said Brad Corson, Imperial Chairman, President and Chief Executive Officer. "Canada's long-term success in achieving its climate goals lies in a collective commitment to innovation, global competitiveness, supportive public policy and open and ongoing dialogue on constructive solutions. Imperial is collaborating with others in industry and governments to develop and commercialize the breakthrough technologies that will reduce emissions and support society's net zero ambitions."

MEG Energy

"We are pleased to be part of this collaborative effort committed to the critical measures needed to achieve net zero green house gas emissions in the oil sands," said Derek Evans, President and Chief Executive Officer of MEG Energy. "Bold action today demonstrates our commitment to tackling climate change and global climate leadership. This alliance working collectively with the federal and Alberta governments and all stakeholders will ensure that Canada continues to be a leading supplier to the world of responsibly produced oil."

Suncor Energy

"Collaboration among companies, innovators and governments is critical to achieving ambitious goals. That's how we built a budding oil sands resource into one of the world's most reliable and ESG-leading oil basins in the world," said Mark Little, Suncor President and Chief Executive Officer. "Canada - as one of the few jurisdictions with industrial-scale commercial CCUS projects in operation -- coupled with Alberta's abundant natural gas resources, geology and relevant technological expertise - is well positioned to lead in this area."

About the Pathways initiative member companies

Canadian Natural Resources Limited

Canadian Natural Resources Limited (Canadian Natural) is a senior oil and natural gas production company, with continuing operations in its core areas located in Western Canada, the U.K. portion of the North Sea and Offshore Africa. Canadian Natural shares trade under the symbol CNQ on the Toronto and New York stock exchanges. Refer to the Company's website for complete forward-looking statements at www.cnrl.com

Cenovus Energy Inc.

Cenovus Energy Inc. is an integrated energy company with oil and natural gas production operations in Canada and the Asia Pacific region, and upgrading, refining and marketing operations in Canada and the United States. The company is focused on managing its assets in a safe, innovative and cost-efficient manner, integrating environmental, social and governance considerations into its business plans. Cenovus common shares and warrants are listed on the Toronto and New York stock exchanges, and the company's preferred shares are listed on the Toronto Stock Exchange under the symbol CVE. For more information, visit cenovus.com.

Imperial

After more than a century, Imperial continues to be an industry leader in applying technology and innovation to responsibly develop Canada's energy resources. As Canada's largest petroleum refiner, a major producer of crude oil, a key petrochemical producer and a leading fuels marketer from coast to coast, our company remains committed to high standards across all areas of our business.

MEG Energy

MEG is an energy company focused on sustainable in situ thermal oil production in the southern Athabasca oil region of Alberta, Canada. MEG is actively developing innovative enhanced oil recovery projects that utilize steam-assisted gravity drainage ("SAGD") extraction methods to improve the responsible economic recovery of oil as well as lower carbon emissions. MEG transports and sells its thermal oil (AWB) to customers throughout North America and internationally.

Suncor Energy

Suncor Energy is Canada's leading integrated energy company, with a global team of over 30,000 people. Suncor's operations include oil sands development, production and upgrading, offshore oil and gas, petroleum refining in Canada and the US, and our national Petro-Canada retail distribution network (now including our Electric Highway network of fast-charging EV stations). A member of Dow Jones Sustainability indexes, FTSE4Good and CDP, Suncor is responsibly developing petroleum resources, while profitably growing a renewable energy portfolio and advancing the transition to a low-emissions future. Suncor is listed on the UN Global Compact 100 stock index. Suncor's common shares (symbol: SU) are listed on the Toronto and New York stock exchanges.

https://www.reuters.com/business/energy/exxon-rejects-union-proposals-end-texas-refinery-lockout-sources-2021-06-17/

June 17, 20214:57 PM MDTLast Updated 2 days ago

Energy

Exxon rejects union proposals to end Texas refinery lockout

Erwin Seba

2 minute read

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Beaumont, TEXAS, June 17 (Reuters) - Exxon Mobil Corp (XOM.N)said on Thursday it rejected proposals by the United Steelworkers union to end a seven-week lockout at the company's Beaumont, Texas, refinery.

Exxon locked out about 650 union workers on May 1 after a prior labor contract expired. It cited a risk of a strike by the USW-represented employees. The plant, which makes gasoline and Mobil 1 motor oil, has continued to operate using managers and replacement staff.

A union official confirmed the two sides met for about two hours on Thursday, but declined to discuss any proposals. No date for another negotiation session has been set.

"They told us: 'We're not compelled to move,'" said Mark Morgan, chairman of the negotiating committee representing union workers at the 369,000-barrel-per-day (bpd) refinery and lubricant oil plant.

In a statement posted online, Exxon said the company and union remain far apart based on Thursday's meeting.

"The union provided five partial proposals which included items that significantly increase cost and do not meet the objectives we informed the union of in January," Exxon said.

The company also said its lead negotiator was prepared to meet with the union's lead negotiator next week.

The USW proposals were offers on specific issues the union was willing to make changes to if Exxon reciprocated on its issues, sources familiar with the matter said.

The company has insisted the union call a vote on its last proposal, which was made in April. Exxon said its proposal is needed to ensure flexibility to compete in low-margin environments.

The USW has refused to call a vote, saying Exxon's proposal would eliminate seniority and create two separate contracts for the refinery and lubricant plant.

Reporting by Erwin Seba Editing by Chris Reese https://www.lundin-energy.com/lundin-energys-johan-sverdrup-barrels-certified-as-carbon-neutrally-produced/

Lundin Energy's Johan Sverdrup barrels certified as carbon neutrally produced

16 June 2021

Lundin Energy AB (Lundin Energy) is pleased to announce that all future barrels of oil the Company sells from the Johan Sverdrup field will be certified as carbon neutrally produced under Intertek Group plc's (Intertek) CarbonZero™ standard. The field has been independently certified at 0.45 kg CO_2e per boe[1], approximately 40 times lower than the world average[2]. Lundin Energy has then taken the further step to neutralise net residual emissions using high quality, natural carbon capture projects.

Highlights

- All future net production from Johan Sverdrup will be certified as carbon neutrally produced by Intertek under its CarbonZero™ standard
- Johan Sverdrup full life of field emissions are certified as one of the lowest in the world at 0.45 kg CO_2e per boe by Intertek under its CarbonClear™ standard
- Residual emissions from net production at Johan Sverdrup have been neutralised using high quality, natural carbon capture projects, certified by the Verified Carbon Standard (VCS)
- The first carbon neutrally produced cargo from Johan Sverdrup has been sold to GS Caltex, Korea
- From 2025, all barrels produced by Lundin Energy will be carbon neutral in their production

The Johan Sverdrup field is the second in Norway to have its emissions independently certified by Intertek, under its CarbonClear™ standard. The field is certified as one of the world's lowest carbon emitting offshore oil and gas fields at 0.45 kg CO_2e per barrel of oil equivalent (boe) for full life of field emissions[1], approximately 40 times lower than the world average[2]. In order to supply a fully carbon neutrally produced barrel, the residual emissions have been neutralised through high quality, natural carbon capture projects, certified by the Verified Carbon Standard (VCS). As a result, there will be no net emissions released during the future production of Lundin Energy's Johan Sverdrup net barrels, which amounts to approximately 100 thousand barrels of oil per day (Mbopd) today and increasing to approximately 150 Mbopd when Phase 2 of the field comes on stream in the fourth quarter of 2022.

The first trade of certified carbon neutrally produced oil from Johan Sverdrup has already been completed with GS Caltex in Korea. The two million barrel cargo will load in July 2021 to be delivered to Korea and was sold as carbon neutrally produced at market price.

Nick Walker, President and CEO of Lundin Energy, commented:

"Since we sold our first cargo of certified, carbon neutrally produced oil from Edvard Grieg earlier this year, we have seen significant interest in the market for this clearly differentiated product. With the certification of our Johan Sverdrup barrels as CarbonZero™, we now have a significant volume of crude being traded as carbon neutrally produced, which I believe will drive significant value for Lundin Energy. As the energy transition continues to accelerate, providing certified, zero emission produced barrels to our customers ensures that they can continue the decarbonisation pathway, delivering a differentiated product to their end users. From 2025, every barrel delivered by Lundin Energy, will be carbon neutrally produced."

Saehong Hur, President and CEO of GS Caltex Corporation, commented:

"We are very proud to purchase the first Johan Sverdrup cargo certified as carbon neutrally produced. At GS Caltex, we are striving to reduce our carbon footprint as part of our commitment to good environmental, social and governance practices. In line with our efforts to expand environmentally-friendly activities, the purchase of Lundin Energy's certified carbon neutrally produced crude oil is another

meaningful step on our path toward a more sustainable and green economy. GS Caltex would like to work together with Lundin Energy further in the future."

[1] Includes emissions from exploration, development and scope 1, 2 and scope 3 supply chain emissions from production.
[2] According to the latest data available from the International Association of Oil and Gas Producers.

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Independent Statistics & Analysis
U.S. Energy Information Administration

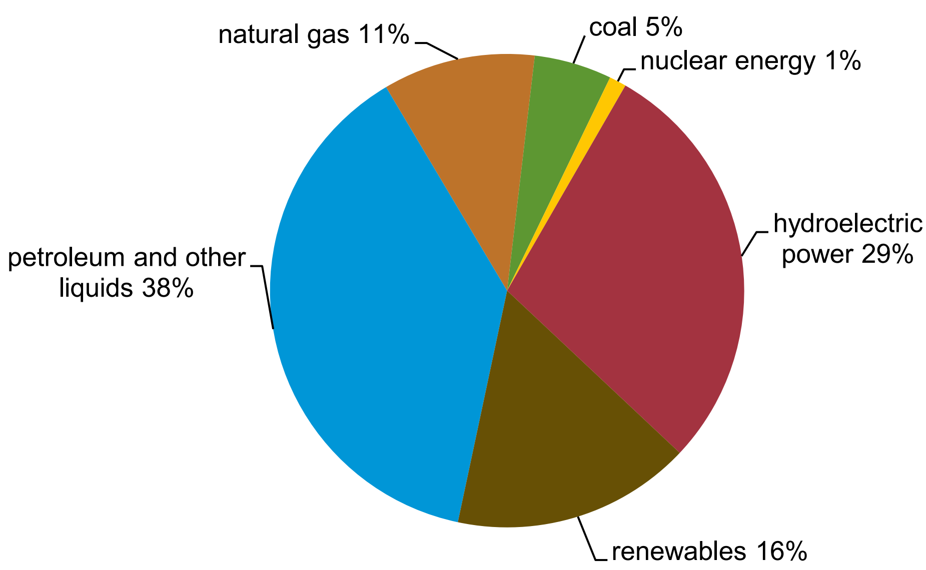
Country Analysis Executive Summary: Brazil

Last Updated: June 14, 2021

Overview

- In 2019, production of petroleum and other liquid fuels in Brazil averaged 3.7 million barrels per day (b/d). That year, Brazil was the eighth-largest producer in the world and the third largest in the Americas behind the United States and Canada.
- Similarly, in 2019, Brazil's economy ranked eighth in total energy consumption globally and ranked third in the Americas, behind the United States' and Canada's economies.[1]
- Economic growth in the past decade has caused Brazil's total primary energy use to grow by 8%.[2] Petroleum and other liquids represented 38% of Brazil's domestic energy consumption in 2019 (Figure 1).

Figure 1. Total primary energy consumption in Brazil by fuel type, 2019



Source: Chart by U.S. Energy Information Administration, based on data from *BP Statistical Review of Energy, 2020*

Petroleum and other liquids

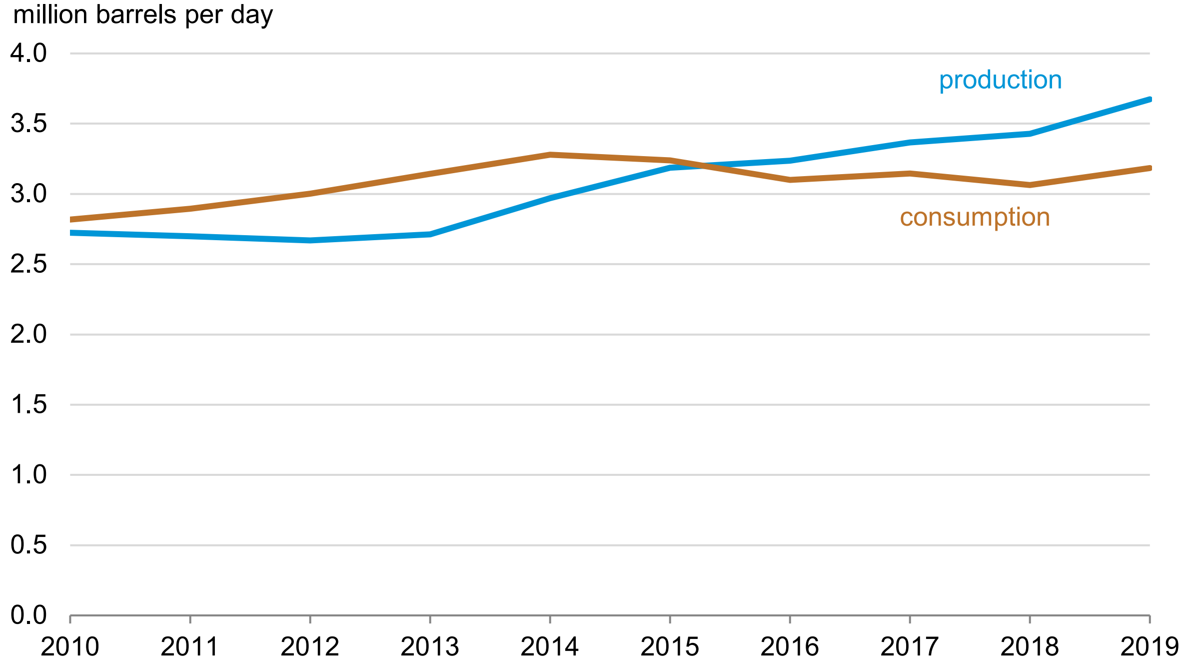
Reserves

- The *Oil & Gas Journal* estimates that as of January 2021, Brazil had 12.7 billion barrels of proved oil reserves, the second-largest oil reserves in South America after Venezuela.[3]

Production and Consumption

- In 2019, production of petroleum and other liquid fuels in Brazil averaged 3.7 million barrels per day (b/d), up from 3.4 million b/d in 2018, continuing a trend of increasing production. Crude oil and condensate accounted for 2.8 million b/d, and the remainder included biofuels (the majority from ethanol) and natural gas liquids (NGLs) (Figure 2).
- The rising use of transportation fuels drove an increase in total petroleum product consumption, which grew to 3.2 b/d in 2019. For the year, diesel (distillate fuel oil) accounted for 42% of total transportation fuels consumed, gasoline accounted for 25%, and ethanol accounted for 21%. Natural gas, biodiesel, and aviation kerosene accounted for the reminder of the transportation sector's consumption volumes.[4]

Figure 2. Brazil's liquid fuels production and consumption



Source: U.S. Energy Information Administration, *International Energy Statistics*

- Between 2012 and 2019, crude oil production rose because of pre-salt oil field development. Pre-salt oil production grew by 1.6 million b/d during this time as a result of more favorable government regulation and more efficient drilling, leading to lower breakeven prices for new fields.[5]
- In 2019, production from the pre-salt oil fields accounted for 62% of Brazil's total output, or 1.3 million b/d according to the Agência Nacional do Petróleo, Gás Natural e

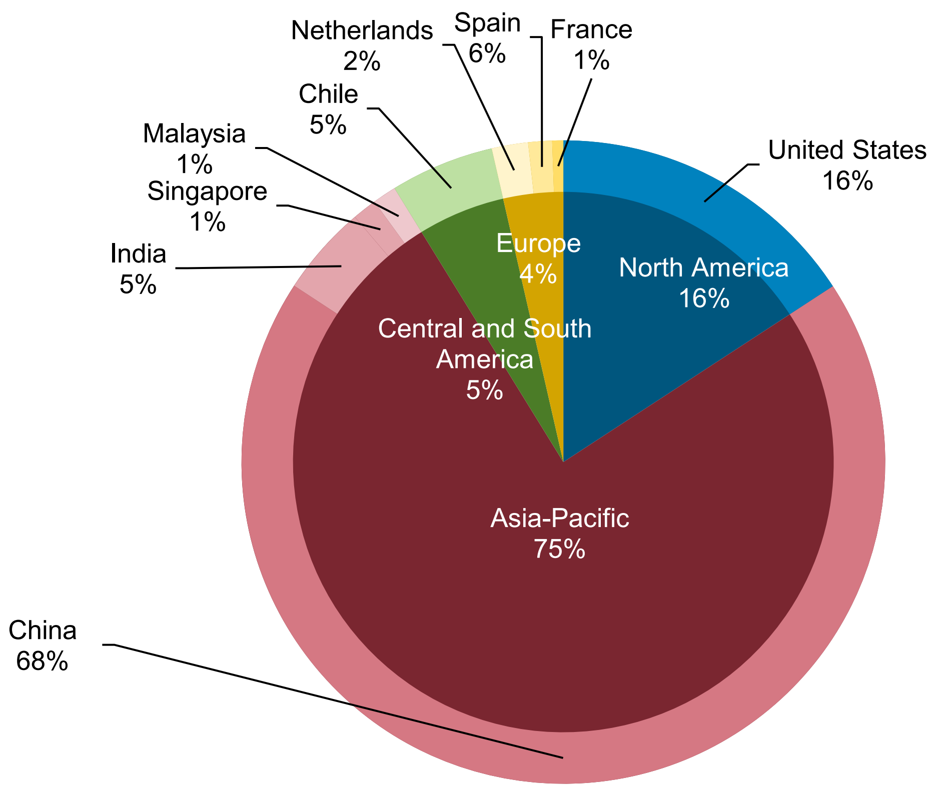
Biocombustíveis (ANP) and the national oil company Petrobras.[6] Over the last two years, Petrobras has significantly increased its production vessels operating in these pre-salt fields to boost crude oil production because post-salt oil reserves have dwindled and it has overcome previous technological difficulties for drilling in deep-water.

- Of the US $46.5 billion in investments in exploration and production planned from 2021 to 2025, Petrobras will allocate 70% to pre-salt assets. Petrobras expects to add up to 13 more offshore floating production storage and offloading vessels (FPSOs) through 2025 to pre-salt fields.[7] During this period, Petrobras will allocate 36% of its total investments to developing the Búzios field, reportedly the largest offshore field in the world.[8]

Exports and Imports

- Brazil's crude oil exports averaged about 1.6 million b/d in 2019, an increase from the previous year and the largest volume reported by the ANP to date.[9] Increased growth in pre-salt oil field production drives Brazil's crude oil production over the next decade, and exports of crude oil will likely increase as well. Petrobras plans to increase exports of light (Lula) and medium (Búzios), sweet, low-sulfur crude oil grades that come from pre-salt fields because they are more valuable in the global oil market. As a result, Brazil's crude oil exports will remain more desirable and competitive over the long term than its heavier crude oils.[10]
- More than 60% of Brazil's exports (1 million b/d) were destined for China, an 18% increase from 2018[11] (Figure 3). Since Petrobras' signed a loan with the Chinese Development Bank in May 2015, exports to China have increased. According to a report by Fitch Solutions, rising exports to Asia to continue to increase in the short-term, given growing commercial ties between the two regions.[12]

Figure 3. Brazil crude oil exports by region and country, 2019



Source: Chart by U.S. Energy Information Administration,based on data from Agência Nacional do Petróleo, Gás Natural e Biocombustíveis (ANP)
Note: Some individual figures do not match the regional total due to rounding.

- The country also imports smaller amounts of lighter grades of crude oil that the heavier grades it produces. Most of Brazil's imports of crude oil come from the Middle East (41%), which produces primarily medium grades. Crude oil from Saudi Arabia accounted for 35% of Brazil's total crude oil imports in 2019.[13]

- Brazil continues to import petroleum products to meet rising domestic demand, to compensate for its fuel price subsidies, and to supplement its underinvestment in the refining sector. In 2019, imports of petroleum products averaged 589,000 b/d, up 5% from the previous year.[14] Most of these petroleum products (426,000 b/d) came from the United States.

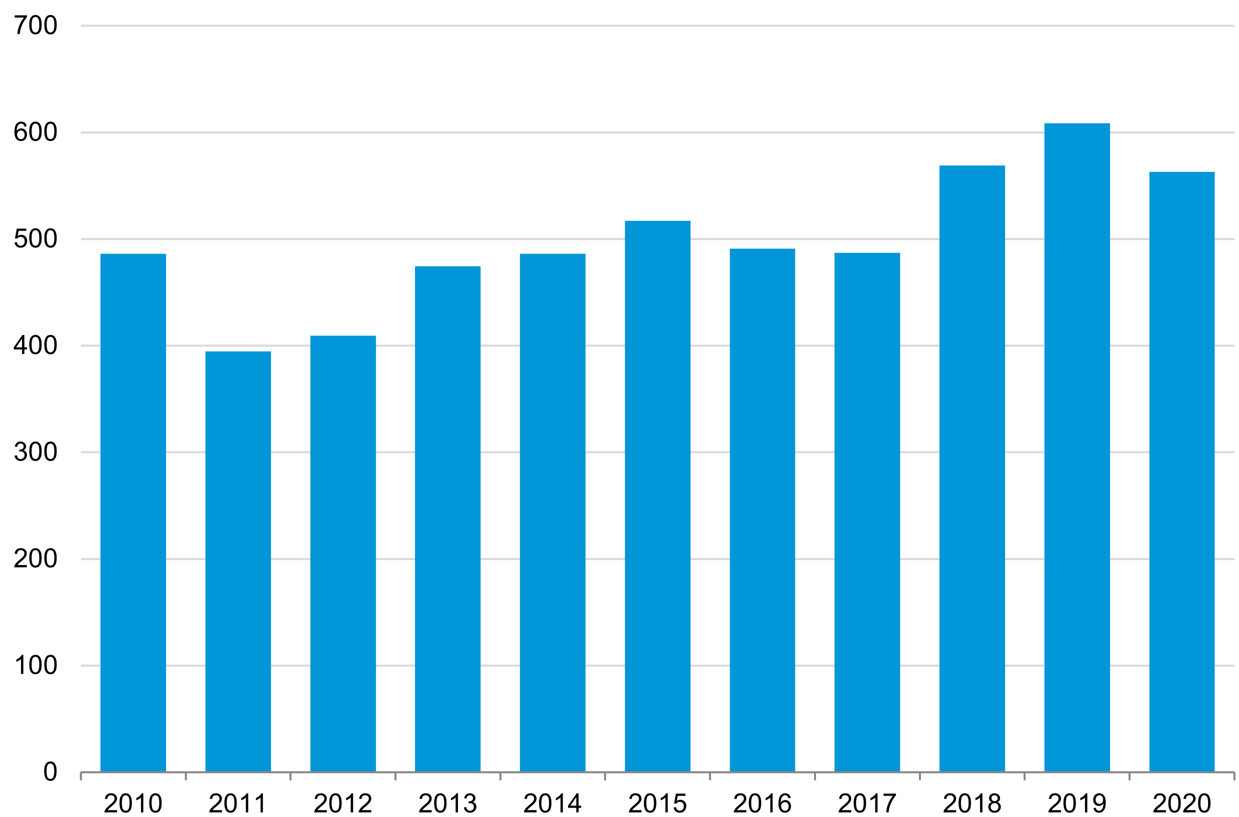
Biofuels

- Biofuels (which includes fuel ethanol and biodiesel) production in 2019 averaged 641,000 b/d. Brazil is the second-largest producer of ethanol in the world after the United States.

- Total fuel ethanol production rose to 541,000 b/d in 2019, the largest annual volume in history (Figure 4). Ethanol production was high because of the larger-than-expected sugarcane crop and low international sugar prices, which encouraged cane millers to produce ethanol for fuel instead of sugar. Ethanol is mainly used for fuel in Brazil. Sugarcane is the main source of feedstock for ethanol production in Brazil, followed by corn.

- The COVID-19 pandemic has particularly affected the global biofuels sector. We expect that global biofuel production in 2020 declined by 12% from the global record in 2019,[15] the first year annual production fell in two decades. The decrease was driven by both lower transport fuel demand and lower fossil fuel prices that weakened the economic attractiveness of biofuels. In 2020, we estimate that Brazil's ethanol production had one of it's largest year-on-year drops in output since 2011.

Figure 4. Brazil's ethanol production
thousand barrels per day



Source: Chart by U.S. Energy Information Administration, based on data from the Agência Nacional do Petróleo, Gás Natural e Biocombustíveis (ANP)
Note: 2020 production is estimated.

- In 2019, Brazil's ethanol exports averaged approximately 33,000 b/d.[16] Brazil shipped most of its ethanol exports (13,000 b/d) to the United States in 2019. Most Brazilian ethanol enters the United States through California because of the fuel's favorable treatment compared with domestic corn ethanol under California's Low Carbon Fuel Standard (LCFS). According to the LCFS scoring system, Brazil's sugarcane ethanol emits less carbon dioxide than U.S. corn ethanol sources, which incentivizes demand for the fuel in California despite available domestically sourced ethanol supply.

- Although Brazil is a major ethanol producer, the country imported more than 22,000 b/d of ethanol in 2019. For the past several years, virtually all ethanol imports have been used for fuel and have been imported from the United States. Brazil primarily produces fuel ethanol from sugarcane. As a result, Brazil produces most of its fuel ethanol during the sugarcane harvest period (May through October). Brazil's imports of U.S. fuel ethanol typically peak in between harvest seasons. In recent years during these inter-harvest periods U.S. ethanol is often priced cheaper than Brazilian sugarcane ethanol, even with a 20% tariff in place on U.S. ethanol volumes.
- Brazil also produces biodiesel. In 2019, biodiesel production rose to a record high of over 100,000 b/d, more than doubling since 2010. Biodiesel production grew in 2019 because of increased diesel consumption and Brazil's requirement that diesel must contain 12% biodiesel. Almost three-quarters of biodiesel is produced from soybean oil.[17]
- Brazil does not export significant amounts of biodiesel. In general, biodiesel exports are low because biodiesel is not price competitive compared with diesel. Biodiesel imports are nearly zero.

Natural Gas

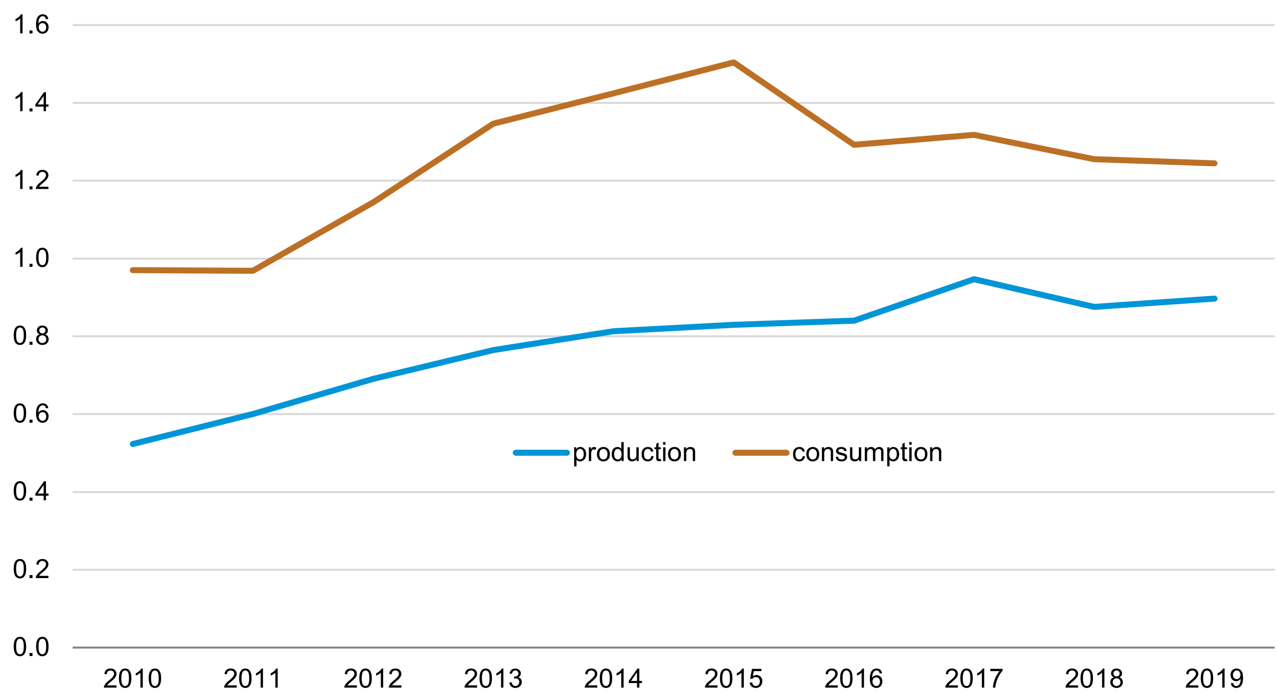
Reserves

- The *Oil & Gas Journal* estimates Brazil had 12 trillion cubic feet (Tcf) of proved natural gas reserves at the beginning of 2020, the third largest amount in South America after Venezuela and Argentina.[18]

Production and Consumption

- In 2019, dry natural gas production in Brazil averaged 897 billion cubic feet (Bcf), rising by 2% compared with 2018 levels. Natural gas production is increasing because of the development of Brazil's vast offshore reserves.
- Currently, Petrobras prioritizes crude oil production over natural gas production. Most natural gas is reinjected for enhanced oil recovery in the pre-salt fields (Figure 5). This strategy and the lack of necessary investment in midstream infrastructure to connect offshore fields with the coast could lead to a decrease in dry natural gas production over the short term.
- Brazil's natural gas consumption averaged 1.2 Tcf in 2019, a slight decrease from 2018 (Figure 5). Natural gas accounted for 11% of all energy use in 2019.[19] Although natural gas consumption in Brazil has continued to grow, the rate of increase has slowed since 2015. Between 2012 and 2015, natural gas consumption increased rapidly because natural gas-fired electric power generation increased.
- In April 2021, President Bolsonaro signed into law the New Gas Law, a new regulatory framework for the natural gas sector. The natural gas market law aims to open the natural gas market to competition, spur investments, and increase competitiveness in the sector.

Figure 5. Brazil's dry natural gas production and consumption
trillion cubic feet



Source: U.S. Energy Information Administration, *International Energy Statistics*

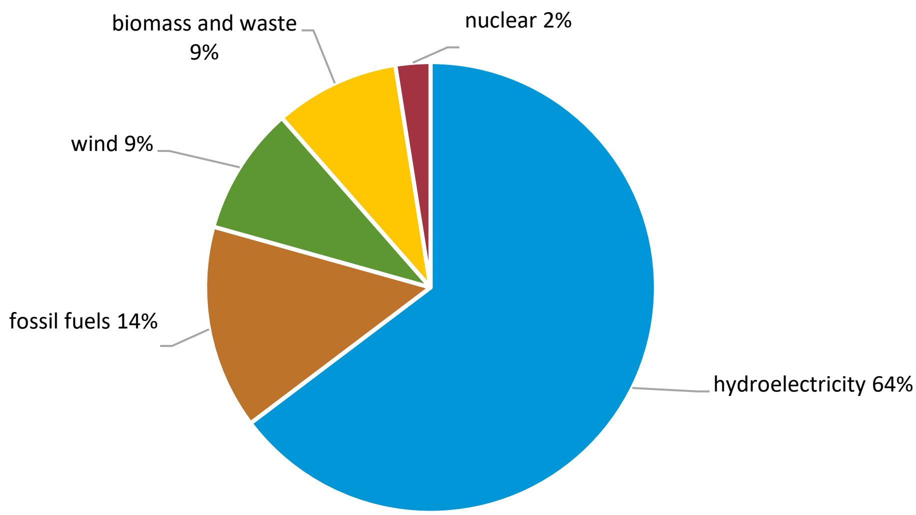
Imports

- Brazil currently relies on imports to meet its natural gas consumption demands beyond what it produces domestically because the country is focused on increasing crude oil production in the pre-salt layers. Brazil's gross imports of natural gas totaled 343 Bcf in 2019, a decrease from 2018 levels. Most (69%) of the natural gas imports came via pipeline from Bolivia, and the remainder was liquefied natural gas (LNG) primarily from the United States, Trinidad and Tobago, and Nigeria. Brazil began importing natural gas via pipeline in 1999 and began importing LNG in 2008. [20]

Electricity

- Electric power generation was 615 billion kilowatthours (kWh) in 2019 (Figure 6). About 83% of total generation came from renewable sources.

Figure 6. Power generation supply, 2019



Source: U.S. Energy Information Administration, *International Energy Statistics*

- Brazil is the second-largest producer of hydroelectric power in the world after China. Hydroelectric generation is the dominant source of electric power generation in Brazil at 64% of total electric generation.
- In 2019, the hydroelectric share of total power generation decreased as a result of lower imports from Paraguay at the Itaipu hydroelectric dam.[21] Imports dropped in part because 2019 was one of the driest years since the beginning of the dam's operation. In addition, because Paraguay's electricity consumption has grown, it needs more hydroelectricity from the Itapu dam, which in term decreases Brazil's imports from the dam. Under the terms of the 1973 treaty between Brazil and Paraguay, any of Paraguay's share of energy from the dam (which sits on the borders of the two countries) that it does not use must be ceded to Brazil and not sold to any other countries. Brazil compensates Paraguay for the imports.[22] This share of imports from the Itaipu dam to Brazil is counted in its national hydroelectric generation total.
- Solar power generation almost doubled between 2018 and 2019, from 3.5 GWh to 6.7 GWh. Although it accounts for a small share of total power generation, solar power generation has substantially increased year over year since 2017. The increase in solar generation is the result of rapid growth in the distributed generation market as the cost of solar power has become more competitive with other renewable sources and continued growth and improvement in the transmission and distribution infrastructure system.[23]
- In its latest 10-year plan, Brazil's government forecasts that renewable sources will account for most of the additions to installed power capacity expansion by 2030. The largest forecasted addition will come from distributed generation, mostly from solar power generation.[24]

Notes

- Data presented in the text are the most recent available as of June 2021.

- Data are EIA estimates unless otherwise noted.

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[1] BP Statistical Review of World Energy, 2020.
[2] BP Statistical Review of World Energy, 2020.
[3] *Oil & Gas Journal*, 2021 Worldwide Reserves, 2020.
[4] Empresa de Pesquisa Energética (EPE), "Brazilian Energy Balance 2020," page 29 (May 2020).
[5] Agência Nacional do Petróleo, Gás Natural e Biocombustíveis (ANP), "Oil, Natural Gas, and Biofuels Statistical Yearbook 2020" Table 1.3 (October 2020).
[6] ANP, "Oil, Natural Gas, and Biofuels Statistical Yearbook 2020," Table 1.3 (October 2020); Petrobras, "Management Report 2019,"page 6.
[7] Petrobras, "Management Report 2020," page 29.
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[12] Petrobras, "Petrobras Overview," page 34. (September 2020); Fitch Solutions, "Brazil: Oil & Gas Report" 2021.
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Background Reference: Brazil

Last Updated: June 14, 2021

Overview

Brazil is a significant energy producer. For many years, Brazil's government has worked to increase domestic oil production, and discoveries of large, offshore, pre-salt oil deposits have transformed Brazil into a top-10 global liquid fuels producer.

Figure 1. Map of Brazil

Source: U.S. Central Intelligence Agency, *World Factbook*

Petroleum and other liquids

Sector Organization

State-controlled Petróleo Brasileiro S.A. (Petrobras) is the dominant participant in Brazil's upstream, midstream, and downstream oil sector activities. The company held a monopoly on oil-related activities in Brazil until 1997, when the government opened the sector to competition. In 2003, Royal Dutch Shell was the first private company to begin commercial oil development when it started production in the Bijupirá and Salema fields in the Campos Basin. Later, other international oil companies (IOCs) began operating in Brazil, including:

- Chevron
- Repsol
- BP
- Anadarko
- El Paso
- Galp Energia
- Statoil
- Sinochem
- BG Group
- Sinopec
- ONGCTNK-BP

In addition to the IOCs, domestic companies began competing in the oil sector: OGX started to produce oil in the Campos Basin in 2011.

Much like in the refining sector, Petrobras holds most of Brazil's logistics infrastructure. The company's main clients, in addition to the Petrobras System, are distribution and petrochemical companies. Petrobras's wholly owned subsidiary, Transpetro, operates Petrobras's oil and natural gas production, logistics, and refining and distribution areas by transporting and storing oil, natural gas, derivatives, and biofuels. Transpetro transports imported and exported cargo of oil and other products.

The investigation of Petrobras (Operation Car Wash) in Brazil and the United States for bribery and money laundering started in 2014 and did not end until early 2021. The scope of the scandal extended to allegations of government corruption in several countries and a kickback scheme involving several international companies. The investigation resulted in a number of arrests and Petrobras losing more than $8 billion. According to Brazil's government, during the seven years of investigation, 278 people were convicted of bribery and money laundering, including some of Brazil's most prominent politicians and business owners.[1]

Petrobras is one of the most heavily indebted national oil companies in the world, in large part due to lost revenue and fines from Operation Car Wash. In 2020, Petrobras reduced its debt from $126 billion at its peak in 2015[2] to $76 billion in 2020[3], and it plans to reduce the debt to $60 billion by 2022.[4] Petrobras's strategy to reduce its debt relies on a strong restructuring plan through a divestment program. At the time of writing, Petrobras's plan includes divesting its stake primarily in its onshore and shallow water oil fields, in approximately half of its domestic refining capacity, and in other segments of transportation and distribution. BR Distribuidora, the fuel distributor subsidiary of Petrobras, which was sold in 2019, is the first case of privatization of a state-owned company through capital markets in Brazil.

The principal government agency charged with regulating and monitoring the oil sector is the Agência Nacional do Petróleo, Gás Natural e Biocombustíveis (ANP). ANP is responsible for issuing exploration and production licenses and ensuring compliance with regulations.

In 2018, the ANP approved changes to rules that set the minimum percentages of the locally sourced goods and services required in exploration and production contracts (known as local content). The local content rules apply to contracts, including the first-ever production-sharing agreements, for older bid rounds and projects through 2030. These changes could significantly affect Brazil's growth in oil production in the future, and breakeven prices could fall significantly and lead to increased oil production. The new local content rules require 50% of good and services for onshore projects to come from local sources and 18% for offshore deepwater projects. The government also instituted less stringent fines for companies that cannot fulfill these local content requirements. However, companies will no longer be able to apply for a waiver of these fines.[5]

Brazil's previous local content rules were seen as a disincentive for investment because of the limited and uncompetitive local supply chain.[6] Previously, oil and natural gas operators in Brazil were required to use up to 85% of equipment and services from domestic industry. This requirement was one of the highest local content requirements in the world, contributing to high breakeven prices.

Exploration and Production

More than 94% of Brazil's oil reserves are located offshore, and 80% of all reserves are offshore near Rio de Janeiro. The next largest accumulation of reserves is located off the coast of Espírito Santo state, which contains about 10% of the country's oil reserves. Reserves will likely rise as producers further explore pre-salt resources.

Pre-Salt Oil

Pre-salt oil refers to oil reserves that are exceptionally deep below the ocean and under thick layers of rock and salt. The large depth and pressure involved in pre-salt production present significant technical hurdles.

The first discoveries in Brazil's pre-salt layer occurred during the 1980s. However, these discoveries were less significant because of the lack of technology at the time. Before 2005, exploration activity was mainly focused on post-salt (above the salt layer) discoveries. In 2005, Petrobras drilled exploratory wells near the Tupi field and discovered hydrocarbons below the salt layer. In 2007, a consortium of Petrobras, BG Group, and Petrogal drilled in the Tupi field and discovered an estimated 5 billion–8 billion barrels of oil equivalent (BOE) resources in a pre-salt zone at 18,000 feet below the ocean surface, under a thick layer of salt. For comparison, EIA defines ultra-deep drilling in the Gulf of Mexico as drilling at 5,000 feet or more.

Further exploration showed that hydrocarbon deposits in the pre-salt layer extended through the Santos, Campos, and Espírito Santo Basins. The Santos and Campos Basins, which hold the majority of the pre-salt reserves, contain approximately 13 billion barrels of Brazil's proven oil combined, which accounts for over 94% of pre-salt reserves and 78% of the national oil reserves. [7] According to a 2015 report by the National Institute of Oil and Gas at Rio de Janeiro-State University, they estimated pre-salt reserves were at 176 billion barrels of undiscovered, recoverable resources of oil and natural gas.[8]

In July 2017, output from pre-salt offshore wells surpassed combined volumes from all other fields for the first time.[9] Pre-salt production reached a record level of 1.9 million barrels per day (b/d) in 2020, and it accounted for over 70% of total oil production in Brazil. Petrobras brought a number of floating production storage and offloading vessels (FPSOs) online between 2018 and 2020 in the pre-salt fields (Table 1).

Table 1: Major pre-salt FPSOs online, 2018–2020

FPSO	Operator	Capacity (thousand barrels per day)	Location
P-74	Petrobras	150	Buzios field
P-75	Petrobras	150	Buzios field

P-76	Petrobras	150	Buzios field
P-77	Petrobras	150	Buzios field
P-68	Petrobras	150	Berbigão and Sururu fields
P-67	Petrobras	150	Tupi field
P-69	Petrobras	150	Tupi field
P-70	Petrobras	150	Atapu field
Campos de Campos dos Goytacazes	Petrobras	150	Tartaruga Verde field
	Total	**1,350**	

Source: Table by the U.S. Energy Information Administration, based on data from Petrobras

Petrobras' Strategic Plan 2021–2025 includes 13 additional FPSOs online through 2025, including the largest planned FPSO in Brazil—FPSO P-80 in the Buzios field, which has an expected capacity 225,000 b/d. The 13 FPSOs' combined capacity is 2 million b/d, and these FPSOs will be located in the Sepia, Buzios, Mero, Marlim, Itapu, and Tupi (formerly known as Lula) offshore pre-salt fields.[10]

Petrobras and its partners (Royal Dutch Shell plc, France's Total SA, China's CNOOC, and National Petroleum Corp) are developing Brazil's first-ever lease under a production-sharing system (PSA), which the government signed in 2013.[11] The Libra Consortium plans to continue undertaking the exploratory phase of discovery evaluation in the Libra block area until March 2025.[12] Under this consortium, the group has installed three FPOS in the Mero field, the third-largest producing field in the pre-salt area.

Regulatory Reforms

Before the pre-salt discoveries, Brazil's law allowed all oil companies to compete in auctions to win concessions and to operate exploration blocks. Brazil's government passed legislation in 2010, creating a new regulatory framework for the pre-salt reserves that included four notable components. The first component was the legislation that created a new agency, Pré-Sal Petróleo SA (PPSA), to administer new pre-salt production and trading contracts in the oil and natural gas industry. The company is also responsible for the technical and financial assessment of any hydrocarbon project in the area. The Mines and Energy Ministry supervises PPSA. The second component allowed the government to capitalize Petrobras by granting the company 5 billion barrels of unlicensed pre-salt oil reserves in exchange for a larger ownership share. The other two components established a new development fund to manage government revenues from pre-salt oil and to lay out a new PSA system for pre-salt reserves. In contrast to the concession-based framework for non-pre-salt oil projects, where companies are largely uninhibited by the state in exploring and producing, Petrobras is the sole operator of each PSA and holds a minimum 30% stake in all pre-salt projects. However, the law included incentives for companies to participate with Petrobras in per-salt development, including a signing bonus of $6.6 billion.

In 2016, Brazil's government passed an offshore oil bill that allows greater private and foreign investment in developing Brazil's offshore oil blocks, modifying the 2010 law. The new provisions changed Petrobras from mandatory operator to preferred operator, allowing the company to choose which blocks to bid on in the pre-salt areas. Except for the Libra field, the government non-competitively granted all pre-salt areas that began development before 2016 to Petrobras

Refining

Unless major refining capacity is added in Brazil, we expect oil product demand to continue to outpace the country's domestic refining capacity. Petrobras operates 13 of Brazil's 17 refineries, which together account for 98% of the country's crude oil distillation capacity (Table 2).[13] Most of the refineries are located near demand centers on the country's coast.

Table 2: Major oil refineries in Brazil

Refinery	Operator	Crude distillation capacity (thousand barrels per day)	Location
Paulínia (REPLAN)	Petrobras	434	Paulínia, São Paulo
Mataripe (RLAM)	Petrobras	279	Mataripe, Bahia
São Jose dos Campos (REVAP)	Petrobras	252	São Paulo, São Jose dos Campos
Duque de Caxias (REDUC)	Petrobras	239	Rio de Janeiro state
Araucária (REPAR)	Petrobras	208	Araucária, Paraná
Canoas (REFAP)	Petrobras	201	Canoas in the Rio Grande do Sul state
Cubatão (RPBC)	Petrobras	170	Cubatão, São Paulo
Betim (REGAP)	Petrobras	157	Betim, Minas Gerais
Abreu e Lima (RNEST)	Petrobras	88	Ipojuca, Pernambuco
Capuava (RECAP)	Petrobras	57	Capuava, Maua, Sao Paulo
Manaus (REMAN)	Petrobras	46	Manaus, Amazonas
Potiguar Clara Camarão (RPCC)	Petrobras	38	Guamaré, Rio Grande do Norte
Fortaleza (LUBNOR)	Petrobras	8	Fortaleza, Ceara
Total		**2,177**	

Source: Table by U.S. Energy Information Administration, based on data from *Oil & Gas Journal*, 2021 Worldwide Refining Survey

In November 2014, the Abreu e Lima, or RNEST, refinery began processing crude oil, marking the first greenfield refinery addition in Brazil in more than a decade.[14] In early 2015, Petrobras officially canceled the 600,000 b/d Premium I and 300,000 b/d Premium II refineries because of the company's critical financial situation.[15] In 2019, Petrobras and China's National Petroleum Corporation (CNPC), its partner, completed an economic feasibility study and concluded it was not economical to complete construction of the previously stalled 150,000 b/d Petrochemical Complex of the Rio de Janeiro Comperj project, located in Itaboraí, Rio de Janeiro. Petrobras canceled plans for refinery construction, along with its associated projects in the Marlim cluster of fields (Marlim, Marlim Sul, and Marlim Leste) in the Campos Basin.

As part of its Strategic Plan 2021–2025 to reduce debt, Petrobras plans to sell eight refineries—RNEST, RLAM, REPAR, REFAP REGAP, REMAN, and LUBNOR—by 2022. This plan will reduce its domestically owned refining capacity from 2.1 million b/d to 1.1 million b/d.[16] In March 2021 Brazil's government approved the sale of RLAM. This sale is the first refinery to be divested. Petrobras put the divestment of the other seven refineries on hold during 2020 in response to the COVID-19 pandemic, but the process has since resumed.[17]

Biofuels

Regulatory Reforms

To address the country's reliance on oil imports and its surplus of sugarcane, the government implemented policies to encourage ethanol production and consumption beginning in the 1970s.

The Ministry of Mines and Energy (MME) implemented the most recent biofuel policy, the National Biofuels Policy (RenovaBio), in December 2019. MME designed the program to support Brazil's goals from the 21st Conference of the Parties (COP21) of the United Nations Framework Convention on Climate Change (UNFCCC). Brazil voluntarily committed to reduce domestic emissions of greenhouse gases (GHG) by 37% by 2025 and by 43% by 2030, compared with its 2005 emissions. RenovaBio targets are based on three mechanisms:

- Annual carbon intensity reduction targets for a minimum period of 10 years starting in 2020
- Certification of biofuels based on how efficiently they reduce GHG emissions
- Decarbonization Credits (CBios) traded in Brazil's Stock Exchange[18]

By creating a market for CBios, the RenovaBio program formalizes compensation for the sector's role in reducing GHG emissions in Brazil.

In Brazil, ethanol and gasoline are competing products in a market where flex-fuel vehicles account for 60% of the total domestic vehicle fleet. Hydrous ethanol (E100) is the substitute product that flex-fuel vehicle owners switch to when its price is at or lower than 70% of the gasoline price.

Brazil's government raised the ethanol blend requirement in gasoline to 27% in February 2015, and it is considering a further increase to 27.5% as a way to reduce gasoline imports.[19] Brazil's ethanol industry has been struggling because of land and labor cost increases as well as government-imposed gasoline price controls, which have been undermining the competitiveness of ethanol as an oil substitute. In addition, sugarcane, the main feedstock in Brazil's ethanol production, is highly sensitive to weather. Crop yields can swing considerably year to year, adding significant uncertainty and costs to ethanol.

Biodiesel production remains tightly regulated by the government. In January 2005, Brazil's government formally introduced The National Program of Production and Use of Biodiesel (PNPB). The program established a minimum blending percentage of biodiesel into petroleum diesel. At first, the suggested blending percentage (2%) was optional from 2005 to 2007, but it became mandatory in January 2008.

The biodiesel blending requirement has increased since 2008 to 13% (March 2021). PNPB lowered the biodiesel blending requirement to 10% between June 16 and June 21, 2020, because ANP approved a brief temporary reduction in response to the COVID-19 pandemic and potential supply shortfalls. Blending requirements are scheduled to increase 1% per year until at least 2028, when the percentage will reach 20% (B20).

Imports and Tariffs

Historically, Brazil has imported ethanol because of droughts that affected sugarcane yields along with the difficulty of producing ethanol from sugarcane, which if not processed quickly tends to rot. The seasonality of sugarcane harvests leaves Brazil with an off-season from January to March. In Brazil, ethanol production is also highly sensitive to commodity prices. For example, because sugarcane is used for ethanol production, high sugar prices may entice producers to switch to sugar production instead of ethanol production. Finally, demand in northeast Brazil for imported ethanol has been high as a result of insufficient local production and the higher cost of transporting ethanol from southern Brazil.[20]

In August 2017, Brazil's foreign trade chamber, Câmara de Comércio Exterior (CAMEX), approved a 20% tax on ethanol imports to take effect once a 600 million liter-per-year quota (10,339 b/d) is exceeded. The import tax ended an agreement between the two largest ethanol producers in the world, Brazil and the United States, to keep global ethanol trade free of taxes as a way to boost the industry and the market.

Since September 2019, ethanol producers have been allowed to import 750 million liters per year (12,924 b/d). Any volume exceeding the quota was taxed at 20%. This quota expired in August 2020, and all ethanol imports once again became subject to the 20% tariff in December 2020.

Natural Gas

Sector Organization

Petrobras plays a dominant role in the entire natural gas supply chain. In addition to controlling most of the country's natural gas reserves and being responsible for most domestic natural gas production, Petrobras also manages natural gas imports from Bolivia. Petrobras controls the national transmission network, and it has a stake in the majority of Brazil's state-owned natural gas distribution companies. Petrobras owns and operates virtually all of Brazil's pipeline infrastructure through its subsidiary company Transpetro. In the upstream and the midstream sector, Brazil's Ministry of Mines and Energy (MME) sets policy, and the ANP is the regulatory authority. In the downstream sector, state agencies oversee regulation.

As part of its strategy to reduce debt, Petrobras is selling its pipeline assets. In April 2017, Petrobras sold a 90% stake in Nova Transportadora do Sudeste SA (NTS) to a consortium of buyers. In 2019, Petrobras sold a 90% stake in Transportadora Associada de Gas (TAG) to a group formed by ENGIE and the Canadian fund Caisse de Dépôt et Placement du Québec (CDPQ). In 2019, Petrobras reached an agreement with anti-trust regulator, Cade, to sell off a series of natural gas transportation and distribution assets, including the remaining 10% stakes in NTS and TAG and a 51% stake in Transportadora Brasileira Gasoduto Bolivia-Brasil (TBG). In 2020, Petrobras continued to divest its assets by selling its liquefied petroleum gas (LPG) distribution unit, Liquigas.[21]

In April 2021, President Bolsonaro signed the New Gas Law, a regulatory framework for the natural gas sector (Bill of Law No. 4476/20). Key changes included:

- Companies interested in building natural gas pipelines will need a simple authorization rather than the more complex concession contract
- Energy regulator ANP will have additional authority to foster competition and reduce market concentration
- Power companies can now distribute natural gas for industrial use. Previously, only Petrobras served industrial natural gas consumers[22]

The goals of these reforms are to end Petrobras's monopoly in onshore markets, to increase foreign investment, and to improve market efficiency.

Production

Most of Brazil's natural gas reserves (84%) are located offshore, and 73% of offshore reserves are concentrated off the coast of Rio de Janeiro. Of the country's onshore natural gas reserves, 59% of the reserves are in Amazonas.[23]

Three basins drive natural gas production in Brazil: Santos, Campos, and Espirito Santo. Recent announcements about additional natural gas discoveries in Brazil's offshore pre-salt layer have generated interest about new natural gas production. Along with the potential to significantly increase oil production in the country, the pre-salt areas are estimated to contain sizable natural gas reserves as well.[24] Associated natural gas projects in the massive pre-salt oil fields will account for the bulk of production growth going forward. However, as a result of the lack of offtake infrastructure from offshore fields to the mainland, challenges remain. Significant volumes of natural gas are currently re-injected or flared because of these infrastructure constraints.

Pipelines

Brazil's pipeline system is a network of pipes situated predominantly along the southeast and northeast areas of the country, from Rio Grande to Sul to Ceará. For years, these pipelines did not connect, which hindered the development of domestic production and consumption. In March 2010, the Southeast Northeast Integration Gas Pipeline (GASENE) linked the southeast and northeast markets for the first time. This 860-mile pipeline, which runs from Rio de Janeiro to Bahía, is the longest pipeline in Brazil.

The other major natural gas market in Brazil is in the Amazon region. In 2009, Petrobras completed construction of the Urucu pipeline, which links Urucu to Manaus, the capital of Amazonas state. This project will facilitate development of the Amazon's considerable natural gas reserves.

In 2011, Petrobras brought Rota 1 online, its first pipeline that transports pre-salt natural gas from the Tupi and Mexilhão fields in Santos Basin to its Caraguatatuba natural gas treatment unit to the REVAP refinery in Sao Paulo state. Rota 2 came online in 2016, and it connects the Tupi field to a natural gas treatment plant in Rio de Janeiro. A third pipeline operated by Petrobras that transports pre-salt natural gas will likely come online in 2022 and will connect the Santos Basin pre-salt fields to the Comperj refinery complex.

In recent years, Brazil's state-owned Petrobras has divested from various midstream assets such as TAG and NTS, which together account for two-thirds of the country's natural gas pipelines. Petrobras's actions provide an opening for more market participants and aim to achieve greater market efficiency and lower prices.

Imports

Brazil relies on natural gas imports from Bolivia, which are transported through two pipelines, to help meet domestic consumption. Brazil also imports small amounts of natural gas from Argentina (Table 3). Imports from Bolivia have been steadily decreasing since 2015 as maturing natural gas fields in Bolivia continue to decline and domestic natural gas consumption rises in Bolivia, decreasing supply available for export.[25] Bolivia's contract to supply a minimum of 87 million cubic feet per day (MMcf/d) of natural gas annually to Petrobras expired in December 2019. Petrobras signed an extension agreement in 2020, but only after cutting the original contracted minimum volume by 60% to 34 MMcf/d. [26] As a result of the recent increase in natural gas production from the vast Vaca Muerta shale field, Argentina is looking to increase its natural gas exports to Brazil.

Table 3. Natural Gas Import Pipelines

Pipeline	Length	Origin	Destination	Capacity
Gasbol	1,960 miles	Santa Cruz, Bolivia [27]	Corumbá, Brazil, contining to São Paulo, Brazil	1.1 billion cubic feet per day (Bcf/d)
Río San Miguel -San Matías	391 miles	San José de Chiquitos, Bolivia	San Matías, Brazil; connecting to the GasOcidente pipeline	98 million cubic feet per day (MMcf/d)

Transportadora de Gas de Mercosur pipeline	281 miles	Aldea Brasilera, Paraná in Argentina	Uruguaiana in Brazil	53 MMcf/d

Source: Table by U.S. Energy Information Administration, based on data from Ministry of Mines and Energy[28] and GasOriente Boliviano [29]

As Brazil's natural gas market continues to grow and available supply of natural gas imports from Bolivia decline, liquefied natural gas (LNG) will likely play an increasingly important role in meeting future demand growth, especially to the northeast markets that are disconnected from supply by infrastructure constraints.

Brazil has four LNG regasification terminals on the Atlantic coast with a combined regasification capacity of 2.2 billion cubic feet per day (Bcf/d) (see Table 4). In 2020, Petrobras announced plans to lease the terminal in Bahia in an effort to divest midstream and downstream oil and natural gas assets.[30] The Guanabara Bay terminal has been idle since 2018 as it undergoes construction to expand capacity.

Table 4. LNG import terminals

Liquefied natural gas (LNG) terminal	Location	LNG provided for	Operator	Regasification capacity
Pecém terminal	Fortaleza	Ceará and Fortaleza thermal power plant	Petrobras	247 million cubic feet per day (MMcf/d)
Bahia terminal	Bahía	Onshore delivery points in the city of Salvado	Petrobras	494 MMcf/d
Guanabara Bay terminal	Rio de Janeiro	Thermal power plants in the region	Petrobas	706 MMcf/d
Sergipe terminal	Sergipe	Usina Termoelétrica (UTE) Porto de Sergipe I combined-cycle natural gas-fired power plant	Golar LNG Limited	742 MMcf/d

Source: Table by the U.S. Energy Information Administration, based on data from Ministry of Mines and Energy and Petrobras[31]

All of Brazil's LNG facilities are floating regasification and storage units (FRSU). Total import/regasification capacity is set to grow with three new projects. The first privately owned terminal, the Sergipe unit, came online in early 2020. The Acu Port project is under construction and will likely come online by 2021. The third project involves a capacity expansion of the existing LNG terminal at Rio de Janeiro.

As Petrobras reduces its involvement in midstream and downstream markets, new projects from private sector firms are emerging. According to a study by federal energy planning company Empresa de Pesquisa Energética (EPE), at least 23 new LNG terminals are planned in Brazil. [32] As of the time of this writing, 10 are in the licensing phase, and 11 are the subject of initial studies.[33] The status of the other LNG terminal is unknown.

Electricity

Sector Organization

Until the 1990s, the government controlled almost all of the electricity sector. Brazil initiated an electricity sector privatization process in 1996 that led to the establishment of Agência Nacional de

Energia Elétrica (ANEEL). The government also established a national transmission grid operator, the Operador Nacional do Sistema Elétrico (ONS), and a wholesale power market, the Mercado Atacadista de Energia Elétrica. ONS operates the national transmission grid, which consists of two large grids (one in the north, one in the southeast) and numerous smaller systems in isolated regions. ONS connected the north and southeast grids in 1999, and the combined system covers more than 90% of Brazil's electricity market.

Although the electricity sector was privatized in the early 2000s, the bulk of Brazil's major generation assets remain under government control. Eletrobras, the largest utility in Brazil in which the government is the main shareholder, is the dominant player in the electricity market.[34] The government also owns most of the electricity transmission network.

In 2004, Brazil's government implemented a new model for the electricity sector. This hybrid approach to government involvement splits the sector into regulated and unregulated markets for different producers and consumers. This approach allows both public and private investment in new generation and distribution projects. In February 2021, President Bolsanaro submitted a plan to privatize Eletrobras, which retains a government share of the company at 45% (down from a 61%). The sale will not include Eletronuclear (a nuclear power company owned by Eletrobrás) or the Itaipu hydroelectric dam. [35]

Transmission

Brazil has a countrywide interconnected grid of over 100,000 miles of high-voltage transmission lines. Most of Brazil's generation capacity is located far from urban demand centers, which requires significant investment in transmission and distribution systems. Total investments in the power transmission sector by 2029 will likely reach $22 billion, or $15 billion in transmission lines and $7 billion in substations. By 2029, an additional 32,000 additional miles will expand the grid.[36] Plans for more distributed generation will help reduce the need for additional transmission infrastructure in the future.[37]

The 1,580-mile long Belo Monte-Rio de Janeiro transmission line in Brazil is the world's longest 800-kilovolt (kV) ultra-high-voltage direct current (UHVDC) transmission line. The line, also known as the Belo Monte UHVDC Bipole II line, transmits electricity from the Belo Monte hydroelectric power plant in Para to Rio de Janeiro. Construction of the transmission line began in September 2017 and was completed in April 2019. The Madeira transmission line, completed in 2014, is one of the longest high-voltage, direct-current line (HVDC) in the world and spans 1,476 miles to link hydropower plants in the Amazon Basin to major load centers in the southeast.

Hydroelectric Power

Brazil is the second-largest producer of hydroelectric power by installed capacity in the world, behind only China.[38] Brazil relies on hydropower to provide more than 66% of its electricity, and in 2019, hydropower met more than 75% of electricity demand.[39] Natural gas- and diesel-fired plants are used only to meet peak demand or as backup baseload sources.

Most of Brazil's hydroelectric plants are located in the country's Amazon River Basin in the north, but Brazil's demand centers are located mainly along the eastern coast, particularly in the southern portion. Brazil's reliance on hydropower for most of the country's electricity generation, combined with the distant and disparate locations of its demand centers, has presented electricity reliability challenges.[40] Increased droughts in Brazil have led to concerns about hydroelectric power generation. Water reservoirs have experienced decreased water levels since 2013, made worse by the 2015–2016 El Niño event in the southeast region that caused the worst water shortage in 35 years.[41] Reservoirs remained at below-normal levels through 2021, which increased the use of more expensive thermoelectric power and led to higher electricity prices in Brazil.[42]

The world's largest hydroelectric plant by installed generation capacity is the 14-GW Itaipu hydroelectric dam on the Paraná River, which Brazil operates with Paraguay. According to Itaipu Binacional, the facility generated a record high of 103 million megawatthours (MWh) of electricity in 2016, as a result of higher rainfall and improved operating efficiency. In 2020, the facility generated 76 MWh after one of the driest years on record.[43] Although Brazil is considering plans to reduce hydropower in the electricity generation mix to minimize the risk of supply shortages as a result of dry weather, new hydro projects continue to move forward. Most notable among these projects is the Belo Monte plant in the Amazon Basin, which reached full operating generation capacity in 2019. This facility is the second-largest hydroelectric plant by capacity in Brazil after the Itaipu Dam and is the fourth-largest hydroelectric plant by capacity in the world.[44] Several other projects planned to come online by the end of the decade, include the 400-megawatt (MW) Tabajara hydropower project in 2027, the 650-MW Bem Querer Hydropower Project in 2028, and a handful of other projects at 100 MW or more between 2026 and 2029.[45]

Other Renewables

The Brazilian Energy Planning Agency´s (EPE) Ten Year Energy Expansion Plan (PDE) for 2020 to 2030 shows that the development of renewable sources will remain a high priority for the government. The PDE expects renewable energy, including hydro, biomass, ethanol, wind, and solar, to account for 48% of all energy supply in the country by 2030.[46]

Brazil has two nuclear power plants: the 640-MW ANGRA 1 and the 1,350-MW ANGRA 2. State-owned Eletronuclear, a subsidiary of Eletrobrás, operates both plants. The ANGRA 1 nuclear power plant began commercial operations in December 1984, and the ANGRA 2 began commercial operations in December 2000. Construction of a third plant, the 1,405-MW Admiral Alvaro Alberto Nuclear Power Station (CNAA), formerly ANGRA 3, started in 1984 but has not yet been completed. We expect nuclear energy's generation share to grow when Angra 3 comes online, which is estimated for 2026.[47]

Solar generation is the smallest portion of electricity generation in Brazil, but its portion is also the fastest growing. Financial incentives such as government subsidies make solar energy cheaper for investors and end users. In 2019, ANEEL proposed to remove these subsidies and to impose a grid access tax for consumers, but President Jair Bolsonaro has postponed any changes.[48] According to the Brazilian Association for Solar Photovoltaic Energy's (ABSOLAR) analysis, more than 4.9 gigawatts (GW) of installed power will be added in 2021. This increase will represent a growth of more than 68% over the country's current installed capacity, currently at 7.5 GW.[49] The Ministry of Mines and Energy (MME) announced in 2020 that it expects over 8 GW of solar capacity to be added by 2030.[50]

Notes

- Data presented in the text are the most recent available as of June 2021.
- Data are EIA estimates unless otherwise noted.

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- 14/06/2021 04:37

Angola reduces oil production forecast by 27,000 barrels/day for 2021 - minister

Luanda, June 14, 2021 (Lusa) – Angola's oil production should reach 1.193 million barrels of oil per day this year, a target of 27,000 barrels lower than initial forecasts, but which the Angolan minister of Petroleum wants to enforce.

"For 2021, the initial forecast was 1,220,400 barrels of oil/day, however there was an interim adjustment and we have a forecast of 1,193,420 barrels and what we are doing is to comply with this new forecast", said the minister of Mineral Resources, Oil and Gas, Diamantino Azevedo, in an interview with Lusa.

The official recalled that the Angolan production comes mainly from mature fields, which have already reached a peak of production and are in a phase of decline, which can only be reversed or mitigated with investments in research, having approved a national strategy to increase the knowledge about the oil potential in Angola.

Also in 2020, the target of 1,283,450 barrels per day was below expectations and Angola produced only 1,271,460 barrels.

“Due to covid-19, the price of oil fell significantly, which also led to a delay in drilling for new wells, which is very important for the sustainability of the forecast”, explained Diamantino Azevedo.

Last year was marked by sharp drops in oil prices, leading the Organization of Petroleum Exporting Countries (OPEC), to which Angola belongs, to act to balance the market, adjusting production.

With projections pointing to an increase in global oil demand between 2022 and 2025, driven by the return to growth of some economies, reflections on prices are expected, but Diamantino Azevedo is cautious about a possible revision of the value defined in the General State Budget ($39).

“We do not have a revision forecast until this moment of the predicted price. It is certain that we would be satisfied if the average price were above the budget forecast”, he declared.

The government official admitted that there was a lack of investment in the sector, stressing that, when he took up his duties, in October 2017, it was clear that changes would be needed, which the executive has been promoting.

Among these, he highlighted the introduction of a new governance model in which the concessionary function to the state oil company Sonangol was withdrawn, now assumed by the National Oil, Gas and Biofuels Agency (ANPG), the creation of a regulatory institute and the launch of a program of oil block tenders extending until 2025, as well as changes to legislation to facilitate investment.

“We will soon launch, through ANPG, a study on the competitiveness of the oil industry in Angola, it will be an instrument to improve the business environment in Angola”, he said.

The Government has also been working on increasing Angola's oil refining capacity, anticipating the construction of three new refineries in Cabinda, whose works have already started, Soyo, currently in negotiations with the American consortium that won the tender, and Lobito, whose project is further behind, although the minister maintains his intention to complete the infrastructure in the current term.

“The project had to be readjusted because we were not satisfied with the cost of capital,” said Diamantino Azevedo, adding that the review of the technological and economic component has already ended and the project will soon be resumed.

Also “advanced” is the process around the exploration of non-oil gas, through a consortium in which Sonangol and multinationals operating in Angola (BP, Chevron, Total and Eni) participate.

"We are finalizing everything so that the consortium can finally take action soon," said the government official, without advancing dates.

RCR // VM

Lusa/End

https://eigpartners.com/eig-led-consortium-closes-12-4-billion-infrastructure-deal-with-aramco/

Jun 18, 2021

EIG-Led Consortium Closes $12.4 Billion Infrastructure Deal with Aramco

Consortium comprised of a cross-section of renowned investors from North America, Asia and the Middle East

WASHINGTON, D.C. – EIG, a leading institutional investor to the global energy sector and one of the world's leading infrastructure investors, today announced the closing of its previously announced transaction with Saudi Arabian Oil Co. ("Aramco"), under which a consortium of investors acquired a 49% equity stake in Aramco Oil Pipelines Company ("Aramco Oil Pipelines"), a newly formed entity with rights to 25 years of tariff payments for oil transported through Aramco's stabilized crude oil pipeline network.

The EIG-led co-investment process in Aramco Oil Pipelines attracted a global group of leading institutional investors from China, the Kingdom of Saudi Arabia, Korea, the United Arab Emirates and the United States including, amongst others, Mubadala Investment Company, an Abu Dhabi Sovereign Investor, Silk Road Fund, Hassana and Samsung Asset Management.

R. Blair Thomas, EIG Chairman and CEO, said: "We are pleased to have completed this transaction with Aramco, a preeminent global energy supplier. The caliber of this marquee global infrastructure asset is further evidenced by the leading investors that have invested alongside EIG. We are honored to be working with this world-class consortium and look forward to a long-term, fruitful partnership."

HSBC Bank plc acted as financial advisor to EIG in connection with the transaction, and Latham & Watkins served as EIG's legal advisor.

About EIG

EIG is a leading institutional investor to the global energy sector with $21.7 billion under management as of March 31, 2021. EIG specializes in private investments in energy and energy-related infrastructure on a global basis. During its 39-year history, EIG has committed over $37 billion to the energy sector through more than 370 projects or companies in 37 countries on six continents. EIG's clients include many of the leading pension plans, insurance companies, endowments, foundations and sovereign wealth funds in the U.S., Asia and Europe. EIG is headquartered in Washington, D.C., with offices in Houston, London, Sydney, Rio de Janeiro, Hong Kong and Seoul. For additional information, please visit EIG's website at www.eigpartners.com.

About Aramco

Aramco is a global integrated energy and chemicals company driven by its core belief that energy is opportunity. From producing approximately one in every eight barrels of the world's oil supply to developing new energy technologies, Aramco's global team is dedicated to creating impact in all that it does. The Company focuses on making its resources more dependable, more sustainable and more useful. This helps promote stability and long-term growth around the world. www.aramco.com.

SAF Group created transcript of excerpt from Gulf Intelligence New Silk Road "Live" Podcast June 15, 2021 https://soundcloud.com/user-846530307/podcast-daily-energy-markets-forum-new-silk-road-live-june-15th

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

At 25:30 min mark.

Gulf Intelligence, Sean Evers Managing Partner. "*Kevin, your outlook for the rest of the week and I'm particularly interested in where you are seeing where shipping is at the moment, where Kpler is pointing its magic little data. There is a lot of congestion still in the US west coast. What's the outlook in Asia?"*

Kevin Wright, Lead Analyst APAC, Kpler. "*yeah just before I go onto that because that is an interesting situation, we actually at Kpler have a webinar this week where we're looking at commodity supercycle and, one of the conclusions, I don't want to spoil the story before its done. But one of the conclusions is that some commodities are doing exceptionally well, iron ore, copper, etc. But oil is very far from in a supercycle. Its a very different scenario at the moment. Coming back to the question about*"

Sean Evers. "*is there any particular reason you guys have identified for that? Why oil is not participating in that. Even LNG seems to be enjoying elevated levels*"

Kevin Wright. "*yeah, as I say its more about other commodities that are probably doing better relative to oil and LNG. Even LNG is a good story, but if you look at the iron ore, $200 per ton level, [??} constantly setting new records and no sign of additional supply whereas the oil cycle is really based on constraint of supply. these levels that we are talking at the moment really have been achieved off the back of OPEC+ cuts. so if you know that there is additional supply that can come onto the market at any time, that's rally sort of saying the market knows this strength is artificial and therefore its not really a supercycle in the same way. so that's really the sort of point that we are making. But as I say, my guys in London and Houston are doing that on Thursday"*

Crude Oil in Floating Storage Falls 2.2% in Past Week: Vortexa
2021-06-14 07:00:01.232 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 95.71m bbl as of June 11, Vortexa data show.
* That's down 2.2% from 97.90m bbl on June 4
* Asia Pacific down 6% w/w to 61.13m bbl
* Middle East down 0.6% w/w to 7.46m bbl
* Europe down 19% w/w to 6.37m bbl
* West Africa up 122% w/w to 5.38m bbl
* North Sea down 76% w/w to 1.22m bbl
* U.S. Gulf Coast down 29% w/w to 659.00k 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

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OIL DEMAND MONITOR: Air Travel Hits Milestones on Recovery Path
2021-06-16 07:40:05 GMT

- **More than 2 million airport passengers a day in the U.S.**
- **Indian fuel sales rebound from virus-led slump in May**

By Stephen Voss

The aviation industry reached several milestones in the past week on its long slog back to normalcy, though international travel remains largely impeded by coronavirus restrictions.
The number of passengers passing through security turnstiles at U.S. airports surpassed 2 million a day on Friday and Sunday, for the first time since March 2020. In Europe, air traffic has improved by one-third in the past month, though the region has fewer than half the number of planes in the sky compared with the equivalent week in 2019.

Seat capacity on planes in France and Germany both surpassed 1 million for the week ended June 14. While that's well above year-ago levels in the depths of the pandemic, it's still considerably lower than levels of 2.5 million and 3.3 million for the equivalent week of 2019. Globally, flight numbers are wedged between the pre-pandemic era and the ruined year of 2020.

The number of commercial flights around the world has risen by 12% in the past month alone, according to daily tracking by FlightRadar24. That leaves the seven-day moving average, as of June 15, at 84,527 flights, some 30% below the equivalent period of 2019, and up 88% from a year ago.

The International Energy Agency anticipates strong demand growth for gasoline and jet fuel next quarter in the industrialized countries of North and South America.

"Northern Hemisphere summer incentivizes travel amid a high vaccination count in much of North America," the agency said in its June 11 monthly report.

Seat capacity data collated by OAG Aviation shows European states are lagging the most among the world's major air travel markets.
China is the only major market which is busier than 2019, by 0.5%, and the U.S. is better than most at only 19%

less than pre-pandemic levels, according to OAG. Both nations benefit from having large domestic markets, where mobility restrictions due to Covid-19 are less stringent. Still, a recent virus outbreak in Guangdong -- China's most-populous province -- has led to many flight cancellations and has hurt jet fuel demand, Mia Geng, a consultant at FGE, said earlier this week.
The U.K. is still 76% below 2019 by seat capacity and monthly passenger numbers for London's Heathrow airport are still very low, hampered by restrictions on international travel.

Road travel is an entirely different story in the U.K. A government index showed vehicle traffic across Great Britain on Monday, June 7, was only 1% below the level seen on the Monday in the first week of February 2020, a benchmark period for the pre-pandemic era.

London Traffic

And among 11 major world cities regularly studied in this monitor, London was the only one to show congestion levels above typical 2019 levels on Monday morning. Paris was not far behind at -5%, according to location technology company TomTom NV, which collates data from in-car navigation devices. TomTom no longer provides data for Chinese cities, which earlier this year also showed pre-pandemic congestion levels.

Traffic levels are generally gaining across Europe as well as in North and South America, according to congestion gauges and direct measurements of traffic on highways and toll roads. German demand for diesel is at about 90%-95% of normal, Thomas Vielmeier, the owner of Vielmeier, a fuels distributor based in southern Germany, said last week.

Even India is already showing signs of a rebound from May, when widespread infections and lockdowns across many India states led to a rapid slump in motor fuel demand. Sales in the first half of June of the nation's two most-used road fuels, diesel and gasoline, rose by 12% and 13%, respectively, from the same period last month, according to people familiar with initial data from the three biggest retailers. That's the first monthly increase since March.

China's daily crude oil processing rose to a record last month, according to Bloomberg calculations based on data published by the National Bureau of Statistics amid stronger margins and increased scrutiny on its independent refiners. In separate data collected by local researcher SCI99, the so-called teapot refiners in Shandong province are now using about 72% of capacity, compared with about 66%-67% during May.

The Bloomberg weekly oil-demand monitor uses a range of high-frequency data series to help identify trends that may become clearer later in more comprehensive monthly figures.
Following are the latest indicators, in the four tables below. The first two show fuel demand and mobility, the next shows air travel globally and the last is refinery activity:

Measure	Location	% y/y	% vs 2019	% m/m	Freq.	Latest as of Date	Latest Value	Source
Gasoline demand	U.S.	+7.3	-14	-3.6	w	June 4	8.48m b/d	EIA
Distillates demand	U.S.	+3.4	-22	-14	w	June 4	3.41m b/d	EIA
Jet fuel demand	U.S.	+45	-42	-20	w	June 4	1.03m b/d	EIA
Total oil products demand	U.S.	+0.8	-16	+1.3	w	June 4	17.7m b/d	EIA
All vehicles miles traveled	U.S.		+0.3		w	June 6	17.2b miles	DoT
Passenger car VMT	U.S.		-0.6		w	June 6	n/a	DoT
Truck VMT	U.S.		+4		w	June 6	n/a	DoT
All motor vehicle use index	U.K.	+46	-1	+6.5	d	June 7	99	DfT
Car use	U.K.	+51	-5	+8	d	June 7	95	DfT
Heavy goods vehicle use	U.K.	+25	+9	-0.9	d	June 7	109	DfT
Gasoline (petrol) avg sales per filling station	U.K.	+60	-4.2	+7.4	w	June 6	6,956 liters/d	BEIS
Diesel avg sales per station	U.K.	+32	-11	+2.1	w	June 6	9,311 liters/d	BEIS
Total road fuels sales per station	U.K.	+43	-8.1	+4.3	w	June 6	16,266 liters/d	BEIS
Gasoline	India	-3.5	-21	+13	2/m	June 1-15	905k tons	Bberg
Diesel	India	-7.5	-21	+12	2/m	June 1-15	2.48m tons	Bberg
Jet fuel	India	+13	-66	-17	2/m	June 1-15	107k tons	Bberg
Total Products	India	-1.5	-21	-11	m	May 2021	15.11m tons	PPAC
Passenger car traffic	Poland	+9	+1	+5.7	w	June 13	23,297	GDDKiA
Heavy goods traffic	Poland	+14	+13	+4.1	w	June 13	4,911	GDDKiA
Toll roads volume	France	+21	-18		w	May 31-June 6	n/a	Atlantia
Toll roads volume	Italy	+34	-9.3		w	May 31-June 6	n/a	Atlantia

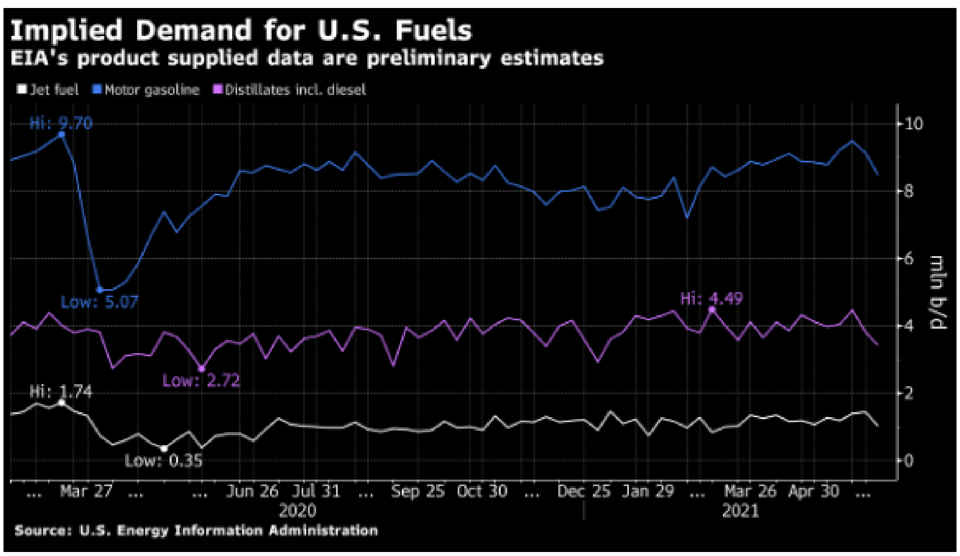
Toll roads volume	Spain	+105	-11		w	May 31-June 6	n/a	Atlantia
Toll roads volume	Brazil	+28	+7.3		w	May 31-June 6	n/a	Atlantia
Toll roads volume	Chile	+102	-5.7		w	May 31-June 6	n/a	Atlantia
Toll roads volume	Mexico	+30	+2.5		w	May 31-June 6	n/a	Atlantia
All vehicles traffic	Italy	+58		+25	m	May	n/a	Anas
Heavy vehicle traffic	Italy	+23		+1.6	m	May	n/a	Anas
Gasoline	Portugal	+112	-18	+16	m	April	75k tons	ENSE
Diesel	Portugal	+62	-10	+5.1	m	April	380k tons	ENSE
Jet fuel	Portugal	+301	-74	+43	m	April	33k tons	ENSE

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

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

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

*** Polish GDDKiA weekly data is compared against appropriate prior-year weeks that also contained the Corpus Christi national holiday.

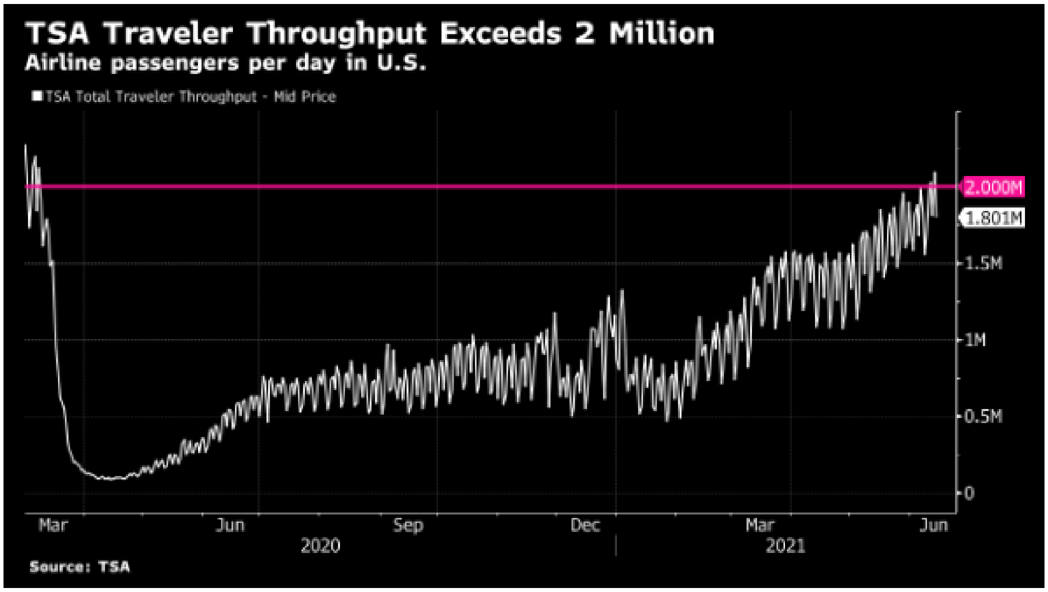


Measure	Location	% chg vs 2019	% chg m/m	June 14	Jun. 7	May 31	May 24	May 17	May 10	May 3	Apr. 26	Apr. 19
		(June 14)		Minutes of congestion at 8am local time								
Congestion	Tokyo	-19	-4	30	27	26	29	31	28	7	32	30
Congestion	Mumbai	-90	+20	4	4	2	2	3	2	1	2	2
Congestion	New York	-31	+29	22	23	2	20	17	19	20	20	20
Congestion	Los Angeles	-47	unch	19	20	3	21	19	19	20	18	20
Congestion	London	+3	-3	39	40	3	41	40	41	2	44	38
Congestion	Rome	-30	unch	34	49	24	38	34	40	29	37	37
Congestion	Madrid	-37	+16	22	27	22	23	19	24	1	28	20
Congestion	Paris	-5	+32	42	42	37	3	32	31	29	23	13
Congestion	Berlin	-18	+12	28	28	26	3	25	24	23	28	26
Congestion	Mexico City	-48	+13	26	24	22	23	23	14	20	23	20
Congestion	Sao Paulo	-47	+3	23	26	28	23	22	22	24	22	22

Source: TomTom. Note: M/m comparison is June 14 vs May 17. TomTom has been unable to provide Chinese data since late April.

Air Travel:

Measure	Location	% chg y/y	% chg vs 2019	% chg m/m	Freq.	Latest as of Date	Latest Value	Source
Airline passenger throughput	U.S.	+237	-29	+3.8	d	June 14	1.80m people	TSA
Commercial flights	Worldwide	+88	-30	+12	d	June 15	84,527	FlightRadar24
Air traffic (flights)	Europe		-54	+34	d	June 14	17,161	Eurocontrol
Seat capacity	Worldwide	+77	-39		w	June 14	70.86m	OAG
Seat cap.	China	+23	+0.5		w	June 14	16.03m	OAG
Seat cap.	U.S.	+154	-19		w	June 14	18.87m	OAG
Seat cap.	India	+59	-48		w	June 14	2.06m	OAG
Seat cap.	Japan	-25	-60		w	June 14	1.65m	OAG
Seat cap.	Australia	+373	-38		w	June 14	1.24m	OAG
Seat cap.	Brazil	+258	-39		w	June 14	1.36m	OAG
Seat cap.	France	+212	-57		w	June 14	1.09m	OAG
Seat cap.	Germany	+115	-70		w	June 14	1.01m	OAG
Seat cap.	U.K.	+82	-76		w	June 14	928k	OAG



Refineries:

Measure	Location	y/y chg	m/m chg	Latest as of Date	Latest Value	Source
Crude intake	U.S.	+18%	+6%	June 4	15.9m b/d	EIA
Utilization	U.S.	+18 ppt	+5.2 ppt	June 4	91.3 %	EIA
Utilization	Gulf Coast U.S.	+15 ppt	+4.6 ppt	June 4	92.9 %	EIA
Utilization	East Coast U.S.	+38 ppt	+10 ppt	June 4	89.7 %	EIA
Utilization	Midwest U.S.	+15 ppt	+6.2 ppt	June 4	90.9 %	EIA
Apparent Oil Demand	China	-0.9%	+4.8%	May 2021	13.58m b/d	NBS
Indep. refs run rate	Shandong, China	-3.3 ppt	+5.3 ppt	June 11	72.0 %	SCI99
State refs run rate	East China	+3.1 ppt	+0.9 ppt	May 27	76.3 %	SCI99
State refs run rate	South China	+3.4 ppt	+9.1 ppt	May 27	86.8 %	SCI99

NOTE: All of the refinery data is weekly, except for SCI99 state refineries, which is twice per month, and the NBS apparent demand, which is usually monthly.

--With assistance from Julian Lee.

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https://coloradosun.com/2021/06/17/colorado-orphan-oil-well-bonding-cogcc/

Colorado doesn't want to foot the bill for abandoned oil and gas wells. Here's how it will avoid picking up the tab.

Senate Bill 181 told the state to strengthen "financial assurance" regs. COGCC now wants operators to guarantee the clean up of each well and the cost could run to the billions.

Mark Jaffe

4:15 AM MDT on Jun 17, 2021

Equipment used to remove old oil and gas wells towers over the Waneka Farm on Baseline Road in Lafayette on June 9, 2021. The centennial farm now is part of the city's open space portfolio. (Andy Colwell, Special to The Colorado Sun)

- **Credibility:**
- Original Reporting
- Sources Cited
- Subject Specialist

Colorado oil and gas regulators looking to avoid a rash of abandoned and unplugged oil and gas wells are proposing to increase financial guarantees by operators for each of their wells — a price tag that could add up to billions of dollars.

The draft financial assurance regulations, released by the Colorado Oil and Gas Conservation Commission, cover all 50,000 oil and gas wells in the state and in general require a full-cost of plugging financial guarantee of $78,000 for each of a company's wells.

The rules, however, take particular aim at what the commission sees as the greatest risk of abandonment: the state's inactive wells — those shut-in, temporarily abandoned or producing less than a barrel of oil a day, as well as low-producing wells yielding less than than five barrels a day.

At the heart of the issue is the question of how great a risk these wells pose and whether there are adequate funds to insure sites are clean and wells are plugged. The industry maintains that the orphan well problem is small in Colorado.

“The goal should be for the oil and gas industry to be cleaning up its mess and that the taxpayer isn’t on the hook,” said Andrew Forkes-Gudmunson, deputy director of the League of Oil and Gas Impacted Coloradans, a community group. “The aim is to avoid some orphan well crisis down the road.”

The industry, however, points to the fact that over decades a total of 579 wells have been orphaned and for the last five years companies have plugged more wells than they have drilled. For example, 2,087 were drilled between 2019 and 2020 and 3,488 were plugged.

“It is critical that the conversation moving forward is rooted in an important reality: the risk of new orphan wells in Colorado is extremely low,” API-Colorado, an industry trade group, said in a statement.

Nevertheless, the COGCC database indicates that there may be tens of thousands inactive and low producing wells..

“Some wells produce so little as to be functionally inactive,” the commission said in its statement on the new rules — a sign that those wells may be near the end of their productive lives.

It is in this group of inactive and low-producing wells the commission sees the greatest threat of wells being abandoned — orphaned — and left for the state to plug.

Colorado currently has 535 orphan-well sites to remediate with 239 wells to plug. A well is classified as orphan when no owner, operator, or responsible party is capable of covering the cost of plugging, reclamation and remediation.

The rules would also charge companies an annual fee of $200 a well to raise $10 million a year to deal with orphan wells.

The COGCC was directed to upgrade its financial assurance rules by Senate Bill 181, which in 2019 made the mission of the commission to protect public health, safety and welfare.

Not all inactive wells are at the end of their lives. Some wells are shut-in or temporarily abandoned when oil prices are low or for maintenance or when a large, new well in the area is being hydrofractured or fracked.

There are 8,458 shut-in wells, which could be put back in production, and 2,903 temporarily abandoned wells, where key equipment has been removed from the site, according to COGCC data.

The rules would give companies six months to return the wells to production, increase the bonds on the wells to full-cost or plug them. Operators would have to supply the commission with a list of wells to be plugged and would have three years to complete the task.

Under present bonding requirements, an operator has to post a bond of $10,000 for each well shallower than 3,000 feet and $20,000 for wells deeper than 3,000 feet or a statewide blanket bond of $60,000 for fewer than 100 wells or $100,000 for 100 or more wells.

The commission created an additional category of “low-producing” wells.

“Once you get to inactive status it may be too late,” Julie Murphy, the commission’s executive director, said during a Zoom meeting Wednesday, the category was a “way to keep an eye on” potentially problematic wells.

For operators with low-producing wells the financial requirements would depend on how many of those wells they have.

An operator with more than 60% of its wells producing less than five barrels a day falls into “Tier 3,” and would have to start paying into a fund over the next 10 years to cover each well at full-cost bonding, $78,000.

“Tier 3 operators may have the highest risk of orphaning their wells, because they have a higher percentage of low producing wells that generate relatively little revenue, and they are plugging a relatively low percentage of their wells,” the commission said.

Those companies below that threshold fall into two categories where they can get blanket bonds for all their wells, with the top category, Tier 1, paying 50% less than Tier 2.

Sam Bradley, a spokesman for the Small Operator Society, representing 65 small oil companies, said the regulations will put small operators out of business, creating a significant number of orphan wells.

“Repeatedly over the last two years we cautioned the commission that this approach would create orphan wells if they weren’t careful, and they completely ignored us,” Bradley said.

Impetro Resources, Bradley’s company, operates 100 wells that each produce less than 15 barrels of oil a day – so-called stripper wells. This includes 15 wells producing less than 2 barrels a day, and 61 producing less than five barrels a day.

That puts Bradley into Tier 3 and would require full bonding at $7.8 million for his operation. If he had two fewer low-producing wells he would be in Tier 2 and his financial obligation would be $1.8 million, he said.

“This is unfair,” he said. “Individual wells don’t go bankrupt, operators go bankrupt.”

The rules would also require full-cost bonding of all wells transferred between two operators and a commission review of any deal in which 30% or more of the wells are low-producing.

“Based on the commission’s experience, transactions in which a large number of low producing wells are transferred are likely to result in higher risk to the public of the new operator orphaning the wells,” the commission said.

Jeremy Nichols, climate and energy program director for the environmental group WildEarth Guardians, called the proposed rules “a mixed bag.”

While “clearly improving things to a degree,” Nichols said the rules are “overly complicated and don’t go far enough in getting industry to pony up and clean up its messes.”

The proposed rules are scheduled for 17 days of hearings in September and October with the regulations going into effect in January.

“We’re hopeful we can end up with a framework that remedies our state’s last orphan wells without punishing the committed companies who are operating responsibly,” Dan Haley, president of the Colorado Oil and Gas Association, a trade group, said in a statement.

Excerpt Bloomberg @TheTerminal Transcript VLADIMIR PUTIN, PRESIDENT, RUSSIAN FEDERATION, HOLDS A PRESS CONFERENCE, GENEVA, SWITZERLAND JUNE 16, 2021

SPEAKERS: VLADIMIR PUTIN, PRESIDENT, RUSSIAN FEDERATION

QUESTION (through translator): One question about the Arctic. You said you talked about that for a long time. The U.S. has accused Russia of militarizing the Arctic. And we heard from Secretary of State Blinken about that in May about concerns of the Russian military. What did you talk about?

PUTIN (through translator): We actively discussed that in-depth, in pretty big detail.

That's a very important and interesting question. As for the Arctic all by itself, and the Northern Passage specifically is extremely interesting for a number of countries, economically speaking.

As for the concerns of the militarization of Americans about the militarization of the Arctic, they are completely unfounded. We're not doing anything that wasn't happening during the Soviet Union. We are establishing an infrastructure that was destroyed.

Yes, we're doing that at the modern level. It includes military and border infrastructure, and also conservation infrastructure. We are creating bases for our disaster relief services, in order to save people in the sea, if it comes for that, God forbid, and also to protect the environment.

What I told our colleagues was that I don't see any concerns. Quite the contrary. I'm firmly convinced that we can cooperate and we should cooperate in this area. Russia and the United States are one of the eight members of the Arctic Council. Russia is chairing that -- the Arctic Council this year.

Moreover, between Alaska and (INAUDIBLE) there is a strait. It's a well-known strait. On the one end is Russia. On the other end is the United States. All of this should spur us to join our efforts.

The situation regarding the use of the Northern Passage is governed by international law by two basic laws, the Convention on the Law of the Sea of 1982, I believe it is, and the Polar Code of Conduct, which consists of a number of documents which were ratified in 2017.

I pointed out something to our partners. Namely, we, Russian, we intend to fully adhere to these international legal standards. We're not violating anything. We're prepared to assist all stakeholders and all companies in exploring the Northern Passage.

Due to climate change, this situation is changing. And we also -- we also have new icebreaking ships. They are the most powerful in the world in Russia. That's why we definitely need to work in this area. And the Convention on the Law of the Sea, I will recall, was drawn up because it describes the legal regime, specifically in internal seas, in territorial seas, in seas that belong to a country, exclusive economic areas, and the free open seas.

Internal seas, those are the seas that are within the territory of a country. Then you have the territorial waters, 12 sea miles. And then you have other categories. And the territorial seas, the military -- military ships can go. As far as the internal seas, there's a particular regime. And we're not imposing anything on anybody there. In internal seas, just so you know, I believe there are fine, the Omsk (ph) Sea, the (INAUDIBLE) gulf, et cetera. There are five total -- five gulfs or bays, maybe they're called.

There are 1,000 nautical miles. This is our sovereign right to either let ships go through there or not, but we're not abusing this rule. We're providing to anyone who -- we're providing it to anybody who wants.

There were around 1,000 applications last year, I think. And most -- some of the ships are under Russian flags. And our – our regulatory authorities monitor compliance with the Polar Code of Conduct, which has requirements for ships.

If all of us together, all stakeholder countries, including the member of the Northern -- the Arctic Council, if all of us are interested in tackling these issues, there are some areas where we need to continue to work. And I'm convinced that we can find an answer. I don't see any problems that we cannot tackle.

https://www.linkedin.com/pulse/accelerating-climate-action-netherlands-marjan-van-loon/?linkId=121597320

Accelerating climate action in the Netherlands

Published on June 17, 2021

Marjan van LoonFollow
President-Directeur Shell Nederland

According to the ruling of the District Court in The Hague on May 26, Shell must reduce its net carbon emissions by 45% by 2030, compared to its 2019 level. The court order applies to the emissions from Shell's operations and our customers. Regardless of whether we appeal the ruling, we are determined to accelerate our net-zero strategy. We will rise to this challenge. This applies to all countries where we have operations and it applies to the Netherlands in particular.

Because when it comes to a transition to a cleaner energy system, I see many opportunities for success in the Netherlands. In fact, if there is one place where you'd expect an acceleration, it is in the Netherlands. It is one of the most advanced economies in the world. The Netherlands has the knowledge, capital, and if I'm to believe my foreign friends and colleagues, the unique talent to organise things. The Netherlands also has a national climate agreement with ambitious goals. By 2030, the Netherlands must have reduced CO2 emissions by almost 50% compared to 1990.

That plan sounds clear, but achieving it is hard and complicated. Over the last 30 years, between 1990 and 2020, the Netherlands has reduced its emissions by 20%, so the country has only 10 years left to achieve the remaining 30%. This leads to a clear conclusion: just like the rest of the world, the Netherlands needs to drastically increase its efforts to tackle climate change. Non-governmental organisations, Shell and pretty much everyone I know agree about that. The question is how.

Today, Shell in the Netherlands has about half the total emissions that we used to have in 1990, including emissions caused by the use of the products we sold. You could say that Shell has already made its contribution to the Dutch Climate Accord. But we don't see it this way. We are not patting ourselves on the back, not in the least. We mostly achieved this reduction because we stopped selling some heavy fuel oil products for commercial reasons, and because we are selling less diesel and natural gas in the Netherlands. These changes to our business did not change the type of energy people used. On the contrary, our customers bought the same products elsewhere, which means the Netherlands hardly benefited from Shell halving its emissions in the country. This is not the way to do it.

If the Netherlands wants to reduce its emissions on a large scale, the types of energy people use – energy demand – will have to change. Shell can and wants to help with this by offering low-carbon alternatives. On this energy map you can see an overview of all our energy transition projects in the Netherlands. For example, Shell opened a filling station for hydrogen buses last week in Groningen in the north of the Netherlands. We have 160 fast charging points for battery electric cars at around 60 Dutch filling stations. And we offer our customers the opportunity to offset their CO2 emissions at our filling stations.

In the months and years ahead, this map is going to get much fuller. In the last year alone, Shell has taken investment decisions worth more than a billion euros to lower our emissions and help change the type of energy that is used by our customers in the Netherlands. We are investing further in offshore wind parks, hydrogen, electric-vehicle charging and biofuels, for example, to help hard-to-abate sectors like aviation decarbonise. We are turning our refinery in Pernis into a modern energy park where we will produce sustainable fuels and raw materials in the future. And by that time, at our chemical park in Moerdijk, we will use plastic waste that can't be recycled to produce all sorts of raw materials for the European market.

Shell will do more and go faster to reduce emissions in a way that benefits the Netherlands. This means offering more low-carbon products. But that is not all. Our customers and society must be encouraged to make the right choices, and discouraged from consuming fossil fuels. This would give Shell and others the economic impetus to accelerate. This requires unprecedented collaboration. With other businesses, with our customers, and with governments that can accelerate change with effective regulations and financial incentives. To give just a few examples: lower excise duties on bio-liquefied natural gas for trucks, so this lower-emission fuel can compete with diesel. Implementation of the European Renewable Energy Directive (RED II) in Dutch environmental law to encourage hydrogen for heavy-duty transport and industry. And tenders for large-scale offshore wind parks that are fast and efficient. I'm convinced that by accelerating change like this, the Netherlands will make the most of that unique talent for organisation to achieve the emissions reduction it needs this decade. We will gladly contribute and work to halve our current emissions again in the Netherlands.

Published By

Marjan van Loon
President-Directeur Shell Nederland
Follow

A Dutch District Court has ruled that **Shell** should reduce its carbon emissions even faster than planned. In this article, I set out what this means for Shell in the Netherlands.

https://www.reuters.com/article/us-shell-usa-permian-idUSKCN2DP0K5

ENERGY

JUNE 13, 202111:52 AMUPDATED 6 DAYS AGO

Exclusive-Shell weighs blockbuster sale of Texas shale assets

By Ron Bousso, Jessica Resnick-Ault, David French

5 MIN READ

LONDON/NEW YORK (Reuters) - Royal Dutch Shell is reviewing its holdings in the largest U.S. oil field for a potential sale, people familiar with the matter told Reuters, marking a key moment in its shift away from fossil fuels as it faces growing pressure to slash carbon emissions.

FILE PHOTO: A Shell logo is seen reflected in a car's side mirror at a petrol station in west London, Britain, January 29, 2015. REUTERS/Toby Melville/File Photo

The sale could be for part or all of Shell's position in the U.S. Permian Basin, located mostly in Texas, which accounted for around 6% of the Anglo-Dutch company's total oil and gas output last year. The holdings could be worth more than $10 billion, the people said.

Shell declined to comment.

There was no guarantee Shell would end up striking a deal for the assets, said the people, who spoke on condition of anonymity to discuss confidential information.

Shell, the second largest western energy company, and its peers have come under investor pressure to increase profits and slash planet-warming greenhouse gas emissions, including by shedding assets.

Any retreat from the Permian would mark a major shift from an area previously identified as one of nine core basins in its energy transition strategy to net-zero carbon emissions by 2050. For all the activity in the Permian, profits have remained elusive because of scale and constant drilling required to boost output.

Shell's energy transition plan, one of the sector's most ambitious, aims to reduce oil and gas output gradually and boost spending on renewables, hydrogen and low-carbon technologies.

A Dutch court last month ordered Shell to reduce its greenhouse gas emissions by 2030, much faster than planned. Shell plans to appeal the ruling, CEO Ben van Beurden said last week, but the company will also deepen emission cuts, a move likely to shrink its oil and gas business.

The energy major plans to reduce oil output by 1% to 2% per year by 2030 through lower investment and disposals. It will increase spending on renewables and low carbon technologies to up to 25% of its overall budget by 2025.

(Graphic: Shell's energy transition spending - tmsnrt.rs/38UTbKj)

PERMIAN HEATING UP

The Permian's rapid growth upended global oil markets last decade with vast production and the ability to ramp output up and down. Its potential for future gains has fueled strong dealmaking even amid uncertainty over the long-term outlook for oil demand.

Benchmark oil prices have soared this year with fuel demand rising as the coronavirus pandemic ebbs. U.S. crude futures are up 49% this year to nearly $72 per barrel, more than double their 2020 lows.

More shale deals are likely this year, with industry experts pointing to big Permian land holders including Chevron and Exxon Mobil aiming to shed some assets to raise cash.

Permian consolidation has accelerated, with Pioneer Natural Resources acquiring two companies, and ConocoPhillips acquiring another. Occidental Petroleum agreed to sell some of its Permian holdings to Colgate Energy for $508 million in a move to reduce its debt.

A U.S. DOWNSIZING

Shell's oil and gas production from company-operated and non-operated rigs in the Permian averaged 193,000 barrels of oil and gas per day in 2020, according to its website, down from about 250,000 the prior year.

Permian production overall is roughly 4.5 million barrels per day, or about 40% of total U.S. output.

A Permian sale would further shrink Shell’s U.S. footprint. The company has agreed to sell all but one of its U.S. oil refineries. It continues major offshore production in the Gulf of Mexico and could green-light a new development, called Whale, in the coming months.

A full sale would mark one of Shell’s largest disposals in recent years and pare net debt to below its $65 billion target, a key part of its energy transition strategy. Net debt reached $71 billion at the end of March.

The Hague-based Shell bought its initial Permian acreage from Chesapeake Energy in 2012 for $1.9 billion and inherited a joint venture that Chesapeake had with Anadarko. They dissolved the venture five years later, leaving Shell with the 260,000 net acres it now holds.

Reporting by Ron Bousso, Jessica Resnick Ault and David French; Additional reporting by Gary McWilliams; Writing by David Gaffen and Ron Bousso; Editing by Daniel Wallis
Our Standards: [The Thomson Reuters Trust Principles.]

Excerpts Shell Insight Upstream Strategy May 25, 2021

SHELL UPSTREAM: A WINNING STRATEGY

SUSTAINING CASH DELIVERY WELL INTO THE 2030s

More focused

- Prioritising 9 core positions that generate 80% of Upstream CFFO
- Lean ventures: maximise value, develop into core or divest
- Focusing exploration on Deep Water and Atlantic margin basins

More resilient

- More replicable investments with lower break-even price and faster payback times
- Developing pathways to net-zero emissions for our Upstream operations
- Payback time before 2035

More competitive

- 2025 aspirations:
  - 20-30% opex reduction
  - 10% Unit Development Costs reduction
  - Availability increase to 92%

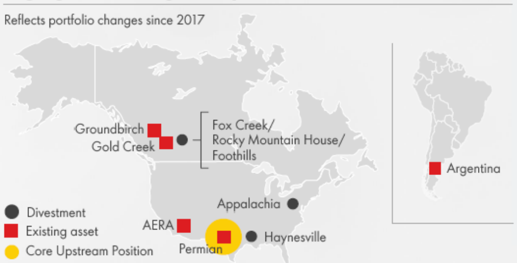
UPSTREAM STRATEGY – SHALES

SHALES TRANSFORMATION

Increased portfolio resilience through higher margin, integrated and cost competitive positions

High-graded integrated portfolio

Reflects portfolio changes since 2017



US
- High-quality position and strong operations
- Trading connection to high-value markets

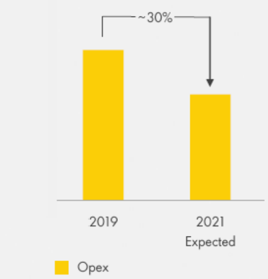
Canada
- Material low-cost gas resource
- Equity gas supply for LNG Canada

Argentina
- Setting a platform for growth
- Acreage quality comparable to the Permian

Strong cash generation

- Generated 14% more CFFO at 23% lower prices in 2020 vs. 2017
- Strong cash through high graded positions and product mix

Transformed delivery model



- Focused structure and operating model
- 40% fewer handoffs and interfaces

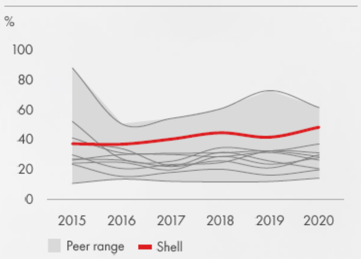
WTI source: NYMEX. Figures represent Shales assets excluding Aera. CFFO figures represent CFFO at asset level.

UPSTREAM STRATEGY – CASE EXAMPLE

HIGH QUALITY POSITION AND EXECUTION IN THE PERMIAN

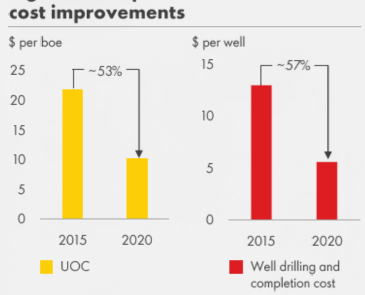
Resilient and predictable returns underpinned by safe, reliable and responsible operations

Among highest oil yields in Delaware Basin



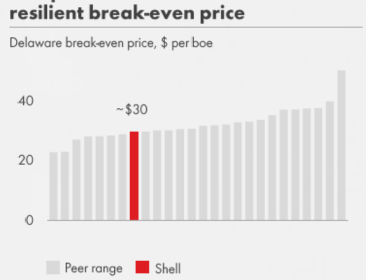
- Positioned in one of thickest formations
- 8+ years of Tier 1 inventory

Significant capital and cost improvements



- Technical and commercial efficiencies
- Innovation and reservoir development

Competitive returns and resilient break-even price



- Average payback time of 2–3 years; IRR's >50%
- Around one-third of oil and gas currently hedged

Peer range comprises IOC's and Independents. Competitive data source Enverus and Shell analysis. Drilling and complete costs normalised to 7,500 ft lateral length. Middle and lefthand charts represent Shell operated assets.

https://nationalpost.com/news/with-merkel-leaving-trudeau-positions-himself-as-new-dean-of-g-7

With Merkel leaving, Trudeau positions himself as new 'Dean' of G-7

As Brexit flared up on the sidelines of the gathering, Trudeau offered his services as mediator. No one has taken him up on the offer, it seems, even as tensions boil over on the last day

Author of the article:
Kait Bolongaro and Alberto Nardelli, Bloomberg News

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Canada's Prime Minister Justin Trudeau attends a plenary session during G7 summit in Carbis Bay, Cornwall, Britain, on June 13, 2021. PHOTO BY PHIL NOBLE/POOL /Reuters

With Angela Merkel preparing to exit the international stage, the longest-serving leader of the Group of Seven is Canada's Justin Trudeau. While he is positioning himself as the new elder statesman, no one sees him owning the role in the way the German chancellor did.

Joe Biden has decades of experience on the international stage, even if he's new to the U.S. presidency. France's Emmanuel Macron has aggressively positioned himself as Merkel's heir in Europe (she will step down after an election in September) and Italy's Mario Draghi, with his years of experience running the European Central Bank, is used to being heard wherever he goes.

In the company of such heavyweights, the leader of the smallest G-7 economy cuts a marginal figure in spite of efforts to be the new "dean," as he became known among the Canadian delegation at this weekend's summit in Carbis Bay on the southern English coast.

Indeed, as leaders walked down the long beach boardwalk on Friday to take their positions for the traditional "family photo," Trudeau trailed behind as Macron made a beeline for Biden. Back in 2017, Macron had gravitated toward the fresh-faced Canadian.

Those visuals tell only part of the story. As Brexit flared up on the sidelines of the gathering, Trudeau offered his services as mediator.

Canadian officials say the 49-year-old prime minister, in power since 2015, genuinely believes he can help the U.K. and the European Union find a solution to their trade dispute over Northern Ireland. No one has taken him up on the offer, it seems, even as Brexit tensions boil over on the last day of summitry.

The host, Boris Johnson, did however tap him to lead a high-stakes discussion on China and how to counter its growing economic and strategic might. A Canadian official said it was in recognition of his experience. Trudeau certainly has experienced the wrath of Beijing.

Canada has found itself increasingly squeezed between the two superpowers, which are also its largest trading partners. Two Canadians — Michael Kovrig and Michael Spavor — remain jailed in China over national security charges after Canadian border guards arrested Meng Wanzhou, Huawei Technologies Co.'s chief financial officer in 2018, under a U.S. extradition request.

"At this meeting, Canada led the way on a common approach to addressing the challenges posed by China," he told reporters at a news conference in Cornwall.

A former senior official from a G-7 country remembers Trudeau at previous summits, including the one in Sicily, when the clean-shaven Canadian was literally mobbed by photographers wherever he went. In Cornwall, his morning runs were ignored.

Back in 2017, in Taormina, the official noted that Trudeau was well liked and that one shouldn't forget that surviving an election cycle in the current political era is no small feat.

Whether Trudeau could aspire to occupy Merkel's throne at the G-7, the official was clear: no way.

https://www.canada.ca/en/environment-climate-change/news/2021/06/government-of-canada-releases-policy-statement-on-future-thermal-coal-mining-projects-and-project-expansions.html

Government of Canada releases Policy Statement on future thermal coal mining projects and project expansions

From: Environment and Climate Change Canada

News release

June 11, 2021 – Gatineau, Quebec

The best available science and economic analysis calls for countries around the world to address the global challenge that is climate change, and to fully seize the economic opportunities that it presents. For the good of the planet's health, the world is moving off thermal coal for energy production, and Canada is leading the way.

Burning thermal coal, the fuel that powered an industrial revolution in a previous century, is the single largest contributor to climate change and a major source of toxic pollution that harms human health. Since co-founding the Powering Past Coal Alliance in 2017 with the United Kingdom and introducing regulations to accelerate the phase-out of conventional coal-fired electricity, Canada has helped set the pace for domestic and international action in addressing this source of greenhouse gas emissions. Last month Canada, alongside other G7 countries, stressed the need to immediately end international investments in thermal coal power generation projects that emit carbon pollution.

As G7 world leaders gather in the U.K. to combat global challenges, including climate change, and as the next step in Canada's commitment to addressing harmful GHG emissions from coal, the Honorable Jonathan Wilkinson, Minister of Environment and Climate Change, today announced the Government of Canada's public policy statement on new thermal coal mining or expansion projects. The statement indicates that the Government considers that these projects are likely to cause unacceptable environmental effects within federal jurisdiction and are not aligned with Canada's domestic and international climate change commitments. Accordingly, this position will inform federal decision making on thermal coal mining projects.

Today's policy announcement provides clarity and regulatory certainty for industry, investors and Canadians. It represents another critical step in our shared path to a cleaner and more prosperous future, and places Canada among the first G7 countries to adopt such a policy.

In parallel to today's announcement, Minister Wilkinson informed Coalspur Mines Ltd. that the policy announced today applies to the consideration of its proposed thermal coal mine expansions at the Vista Coal Mine near Hinton, Alberta.

Canada's abundant natural resources give this country a competitive advantage we have always used to support jobs and prosperity. In the global race to carbon-neutral economies by 2050, Canada continues to build on its long-term competitive advantage by focusing on environmental sustainability and clean growth while supporting workers and communities.

That is why, for example, Canada's strengthened climate plan—A Healthy Environment and a Healthy Economy—committed $964 million over four years to advance smart renewable energy and grid modernization projects to enable the clean grid and jobs of the future. And that is why, to mitigate the impacts of the domestic phase out of coal-fired electricity, Budgets 2018 and 2019 provided $185 million for skills development, economic diversification, and infrastructure to support coal workers and communities.

The evidence is clear: the continued mining and use of thermal coal for energy production in the world runs counter to what is needed to effectively combat climate change and seize the economic opportunities that it presents. It is in this context that the Government has announced this policy today and will continue to work with Canadians to deliver strong climate action.

Quotes

"New thermal coal mining projects or expansions are not in line with the ambition Canadians want to see on climate, or with Canada's domestic and international climate commitments. Eliminating coal-fired power and replacing it with cleaner sources is an essential part of the transition to a low carbon economy, and as a result, building new thermal coal mines for energy production is not sustainable."
– The Honourable Jonathan Wilkinson, Minister of Environment and Climate Change

Quick facts

- In 2018 the federal Government introduced regulations to phase-out conventional coal-fired electricity across Canada by 2030.
- Limiting GHG emissions associated with conventional coal-fired electricity will protect the air we breathe, eliminate 12.8 million tonnes of carbon pollution from our atmosphere in 2030, and help Canada avoid an estimated 260 premature deaths, 40,000 asthma episodes and 190,000 days of breathing difficulty.
- Aided by the Powering Past Coal Alliance, Organisation for Economic Co-operation and Development countries have closed over one third of their total coal power capacity through retirement commitments and phase-out policies.
- In 2019, Export Development Canada committed to no new financing for coal-fired power plants, thermal coal mines or dedicated thermal coal-related infrastructure. This May, all G7 countries also agreed to take concrete steps towards an end to government investment for unabated international thermal coal power generation projects by the end of 2021.
- Canada's electricity grid is over 80% emissions-free—one of the cleanest in the world—and is on track to meet its goal of having 90% non-emitting electricity generation by 2030 .
- In October 2020, the Canada Infrastructure Bank committed to invest $2.5 billion in clean power projects over the next 3 years.
- In Canada's strengthened climate plan of December 2020, a Healthy Environment and a Healthy Economy, Canada committed $964 million over four years to advance smart renewable energy and grid modernization projects to enable the clean grid of the future. This includes support to increase renewable power generation capacity such as wind and solar, and the deployment of grid modernization technologies such as power storage.

https://ici.radio-canada.ca/nouvelle/1802004/charbon-environnement-contamination-selenium-poisson?depuisRecherche=true

Ottawa imposes environmental assessment on metallurgical coal mines

Tiphanie Arugula
10:10 am | Updated at 2:48 p.m.

The federal government will impose an environmental assessment on all coal mining projects that could release selenium into waterways.

The decision announced Wednesday will include all proposals from the eight exploratory projects underway in the Rocky Mountain foothills region of southwestern Alberta, Environment Minister Jonathan Wilkinson said.

« I think all Albertans expect an issue like selenium and its effects on waterways and aquatic life to be evaluated » , he said.

Selenium is a trace element that can cause malformations in fish if it accumulates in too large a quantity. It is found in the ashes from coal mining.

The Teck mine in southern British Columbia contaminated waterways in the region . The population of a rare fish has collapsed .

« We have to take into account the effects on fish and fish habitat, which are federal areas. It is therefore appropriate for the federal government to impose an environmental assessment " , Wilkinson said.

The Minister points out that the Impact Assessment Act automatically applies to projects that plan to produce more than 5,000 tonnes of coal per day, but that he can also designate other projects as he sees fit.

A heated debate in Alberta

The risk of selenium contamination is one of the reasons many landowners, First Nations people and environmentalists oppose proposed projects in southwestern Alberta.

These plans have been at the heart of controversy since the Alberta government revoked the 1976 policy that excluded surface mines in the eastern foothills of the Rockies.

He has since reversed his decision , but several municipalities, many Albertans and First Nations members have asked Ottawa to get involved in the file.
They believe that federal assessments are more rigorous than provincial assessments and allow for more public participation.

Jonathan Wilkinson announced his decision in a letter to NDP MP Heather McPherson, who in March asked him to impose an environmental assessment for all coal mines in the Rockies. It was based on a petition with 18,000 signatures.

When Minister Wilkinson joined me, I was delighted. This is a great first step in protecting the Rockies of Alberta , she responded. This is not enough, however.

Cumulative effects forgotten

Edmonton MP Strathcona noted that a regional assessment such as the one she had requested would have assessed the cumulative effects of all of these projects.

The Minister ruled out such an assessment for reasons of time.

« Given the pace of development [in Alberta], we determined that this would not be the most appropriate tool » , he said.
« Now that we have this protection to face the urgency of the situation, let's take the time to do a cumulative assessment of the projects » , replied Ms. McPherson.
Ecojustice lawyer David Khan is also disappointed that a regional assessment is not taking place. According to him, this request also from members of First Nations was the only way to assess the impacts of mining on indigenous rights.

« There have been long concerns about a lack of cumulative effects review when environmental assessments are done only on a project-by-project basis “, he explained.

More and more studied projects

According to Wilkinson, the new policy will give more certainty to the industry on what type of projects will be evaluated and how it will be carried out.

“We don't say no to all projects. We make sure that these projects are carried out in the best way for the environment.”
A quote from:Jonathan Wilkinson, Minister of the Environment

Last week, the minister announced that he would make it more difficult to operate new thermal coal mines. The government is also preparing new regulations on discharges from mines such as selenium. The Alberta government has set up consultations on the best policy to adopt to develop this resource. The group is due to report in November.

Equinor Capital Markets Day June 15, 2021

RENEWABLES

Accelerating development of our **strong industrial position**

Building on competitive advantages and established position

~23 BILLION USD

Gross capex to renewables 2021-26

Bringing ambitions forward, based on early access at scale

12-16 GW

Installed capacity 2030

Equinor share

Enhancing returns through farmdowns and financing

4-8%

Real base project return

Equivalent to 6-10% nominal returns. Excluding effects from farmdowns and project financing

12-16%

Nominal equity return

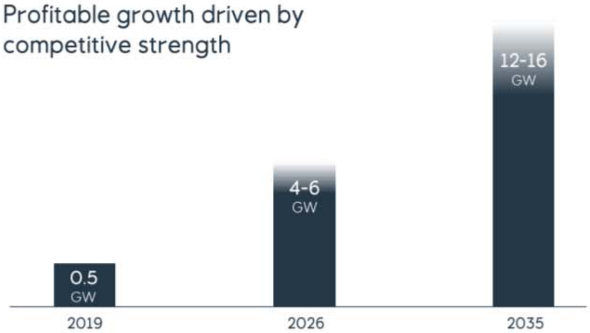
US and UK development projects with secured offtake contracts

Equinor Business Update Dec 2020.

Value driven growth in renewables

Value creation and ability to increase returns

Profitable growth driven by competitive strength



1. Real unleveraged returns corresponding to 8-12% nominal unleveraged returns

Equinor equity generation capacity. 2026 and 2035 include 15.2% share of Scatec Solar ASA

OIL & GAS

Capitalising on our **advantaged portfolio**

Strong cash engine, maintaining production at current levels to 2030

>45 BILLION USD
Free cashflow oil & gas 2021-26
Based on 60 USD per bbl

Resilient portfolio with short payback time, optimising around high value areas

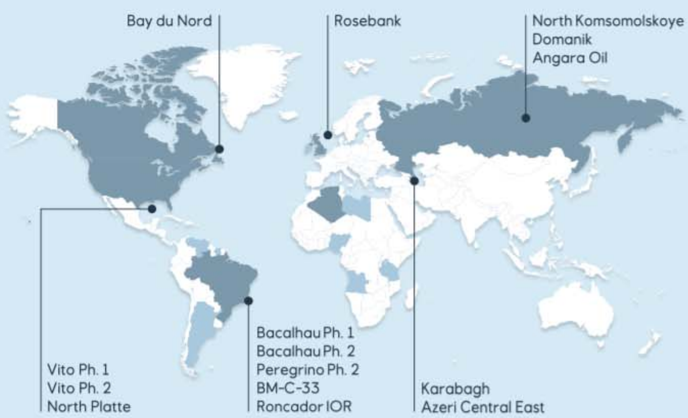
<35 USD PER BBL
Break-even, projects coming on stream by 2030
Volume weighted average

<2.5 YEARS
Average payback time
Based on 60 USD per bbl
Volume weighted, from production start including IOR

Setting a new standard for carbon efficient operations

~6 KG PER BOE
CO_2 upstream intensity by 2030
Scope 1 CO_2 emissions, Equinor operated, 100% basis

Focused major projects



15 major projects in **6** countries

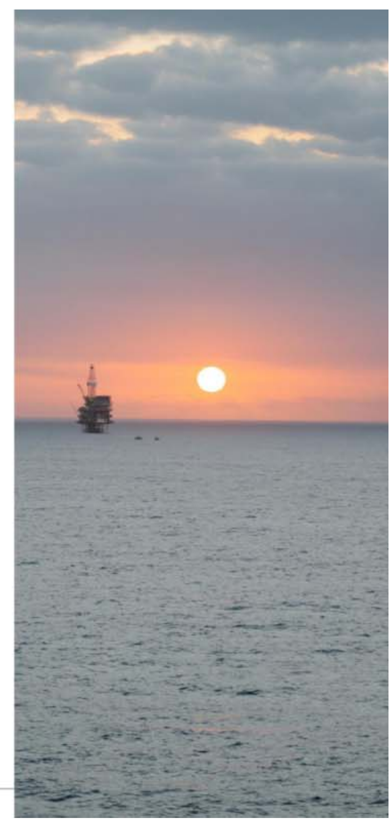
● Highlighted major projects

Attractive project portfolio

>10 BILLION USD
Net present value
Based on 60 USD per bbl

<8 KG PER BOE
CO_2 upstream intensity
Project lifetime intensity Scope 1 CO_2 emissions, Equinor operated, 100% basis.

>20%
Internal rate of return
Based on 60 USD per bbl
Volume weighted average
Real terms



https://www.audi-mediacenter.com/en/press-releases/partnership-with-energy-providers-audi-funding-expansion-of-renewable-energy-to-increase-the-number-of-charging-stations-in-europe-that-use-green-power-14025

06/17/21

Partnership with energy providers: Audi funding expansion of renewable energy to increase the number of charging stations in Europe that use green power

Skip sidebar

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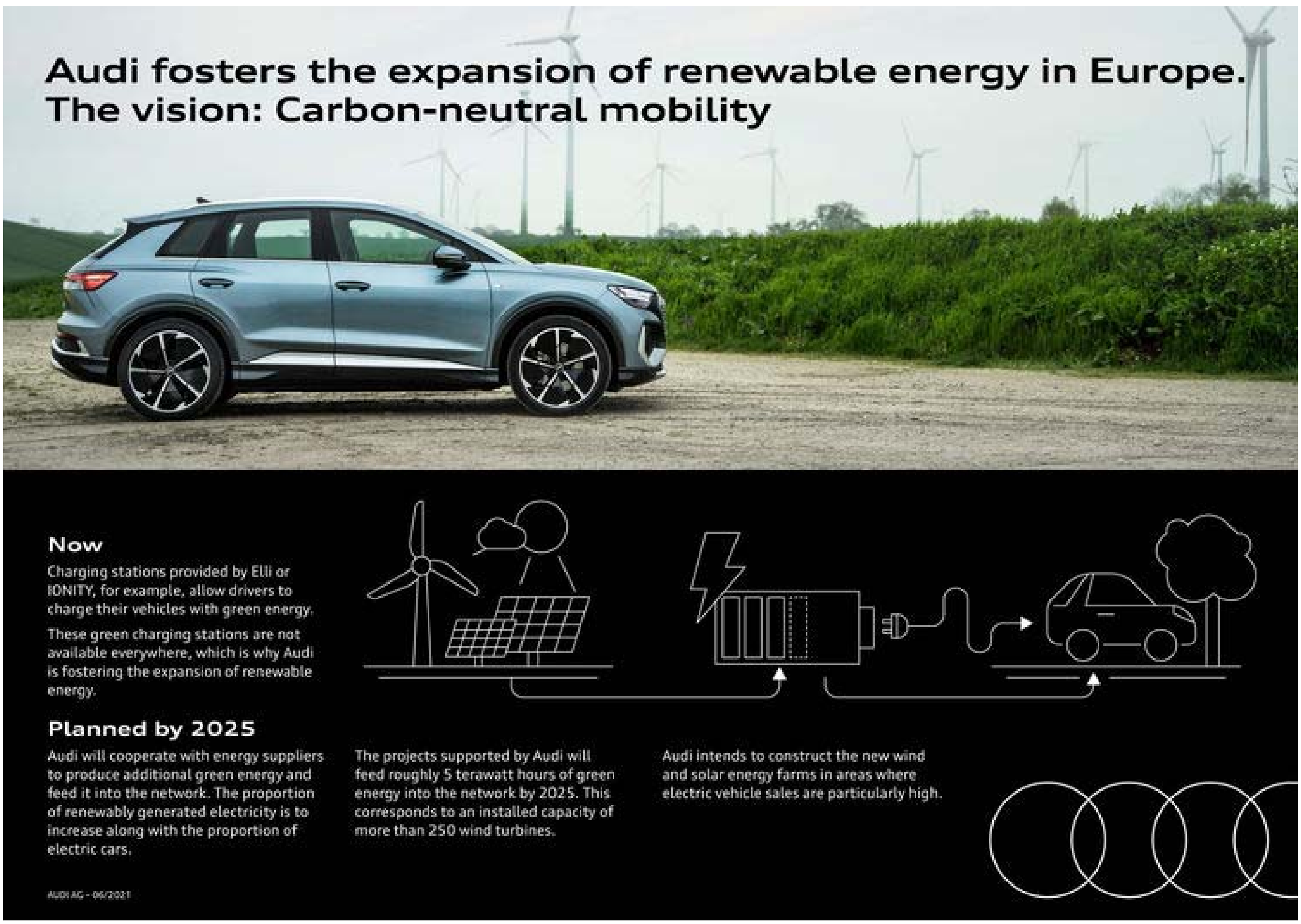

- Next step towards the vision of carbon-neutral mobility: Audi funding the expansion of wind and solar farms in Europe
- The Audi-funded projects are expected to feed an additional 5 terawatt hours of green power into the grid by 2025

- First project is a solar park in Germany with RWE starting in 2022

- Oliver Hoffmann, Member of the Board of Management for Technical Development: “We’re working hard to make carbon-neutral mobility possible”

The company’s vision is absolutely clear: Audi wants to become a provider of carbon-neutral mobility. To achieve this goal, the company is partnering with energy providers to support the expansion of renewable energy sources. The aim is to work with these different partners to build new wind and solar farms in various European countries by 2025, which together are expected to generate around 5 terawatt hours of additional green power. This corresponds to an installed capacity of about 250 new wind turbines. The aim is for the proportion of electricity generated from renewable sources by the cooperation partners to increase along with the increasing proportion of electric cars. The first project, a solar park in the German state of Mecklenburg-Vorpommern, is being developed in collaboration with the German utility company RWE. The plant will come on stream in 2022 and is designed for a total capacity of 170 million kilowatt hours. Encompassing nearly 420,000 solar panels, it will be one of the largest independent solar parks in Germany. Further projects are to quickly follow.

Partnering with energy providers is the next step in achieving the company’s vision of net-zero carbon emissions by 2050. To this end, Audi is examining the entire life cycle of its models, which in professional circles is divided into three stages: the manufacturing stage (starting with the extraction of raw materials through component manufacturing and automobile production), the utilization stage (vehicle operation including the supply of fuel or electricity), and recycling. As an intermediate goal, Audi aims to reduce the carbon footprint of its fleet by 30 percent over its life cycle by 2025. By partnering with European energy suppliers, Audi aims to successively decarbonize the utilization stage.

When it comes to electric cars, one of the most important factors is the power used to charge them. Electric cars do not emit carbon on the road, but the generation of electricity also produces carbon emissions – far more when the power is generated from fossil fuels than from renewable energy sources. That’s why Audi will soon be directly funding the generation of renewable electricity – the partnership with energy suppliers is also intended to cover charging processes that aren’t yet carried out with green power today. The objective is to increase the share of electricity generated by the partners from renewable sources in conjunction with the further increase in the share of electric cars on the road. Audi customers can, for example, already use the green power solutions offered by Volkswagen subsidiary Elli (Electric Life) to charge their cars at home today. For charging on the road, the IONITY charging network and many other charging point operators already rely on green power.

“We’re working hard to make carbon-neutral mobility possible. The expansion of renewable energy sources at an industrial scale is the next, logical step. Our first project, a massive solar park in Mecklenburg-Vorpommern, will come on stream as early as 2022,” says Oliver Hoffmann, Member of the Board of Management for Technical Development. In this context, the company is taking a regional approach and prioritizing the implementation of projects in areas where charging demand is particularly high. By helping generate additional green power, Audi and its partners are ensuring that the renewable energy already available does not compete with the consumption of the Audi fleet. Over the long term, the company plans to expand to other regions, including outside Europe.

A comprehensive approach: decarbonizing the manufacturing stage

Audi is also focusing on the manufacturing stage, and already launched a CO_2 program in the supply chain back in 2018 to work with its direct suppliers to identify potential savings. Closed material cycles, gradually increasing the use of secondary materials, the use of recycled materials in plastic components, and the use of green power all offer concrete potential for reducing carbon emissions.

Audi intends to contractually agree on the implementation of these measures with its suppliers for upcoming orders and for them to be fully in force by 2025. The use of green power has already been an integral part of supplier contracts with HV battery cell manufacturers since 2018. The company analyzes the effectiveness of these measures on the basis of life cycle analyses and has them certified by independent third parties. This comprehensive program not only encompasses direct suppliers, but also subsuppliers.

All of the company's activities to reduce the environmental footprint of Audi sites worldwide are consolidated in its Mission:Zero environmental program. A key goal is to achieve net-zero carbon emissions at all sites* by 2025. Audi Brussels already achieved this goal in 2018, Audi Hungary followed in 2020. All of Audi's European production sites exclusively source green power. Audi e-tron GT[1] manufacturing at Böllinger Höfe and Audi Q4 e-tron manufacturing at the Volkswagen factory in Zwickau are both net-zero* production processes. The same also applies to the delivery of all Audi e-tron models to customers in Europe and the United States – all carbon emissions from the supply chain, production, and logistics that cannot be prevented are offset through carbon credits that support measures to combat climate change. These are certified by the non-profit organizations The Gold Standard or Verified Carbon Standard.

*Audi understands net-zero carbon emissions to mean a situation in which, after other possible reduction measures have been exhausted, the company offsets the carbon emitted by Audi's products or activities and/or the carbon emissions that currently cannot be avoided in the supply chain, manufacturing, and recycling of Audi vehicles through voluntary offsetting projects carried out worldwide. In this context, carbon emissions generated during a vehicle's utilization stage, i.e. from the time it is delivered to the customer, are not taken into account.

Audi Plans No More New Gasoline, Diesel Cars From 2026: SZ
2021-06-17 15:40:18.166 GMT

By Steven Arons
(Bloomberg) -- Audi CEO Markus Duesmann told labor representatives and top executives on Thursday that the company won't even launch hybrid models anymore, starting in 2026, Sueddeutsche Zeitung reports without saying how it got the information.
* A3 and A4 models are to be re-designed and will then be named A3 e-tron and same applies to A4
* Last car to have internal combustion engine that Audi will launch is a Q off-road model that will be sold until ~2033
* Audi plans to subsequently only sell electric cars
* NOTE: VW Sets Europe's Most Significant Electric-Car Sales Target Yet
* NOTE: Audi Sees Electric Cars Occupying Half the Global Market by 2030

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To view this story in Bloomberg click here:
https://blinks.bloomberg.com/news/stories/QUUQZ7T0G1KY

INTRODUCTION

Thank you Spencer for a brilliant overview – and highly entertaining, as always.

What we have just heard has informed everything else you are going to hear from us for the rest of this week.

What I'd like to do now is three things.

First, emphasize **the connections** between our **strategy, our ambition** and the context provided by the **energy outlook.**

Second, to provide a brief recap of the three things we set out on the 4th of August – the **strategy** itself, the **financial frame** and the **investor proposition**.

And **third**, introduce **five key questions** we have heard so far about the strategy – and that we are aiming to answer this week.

1. CONTEXT

Now starting with those connections.

As you just heard, global energy demand is going up.

Emissions do not look like they are coming down fast enough.

The world is not on a sustainable path.

But as Spencer points out – this is not set in stone – there is no one fixed pathway – there is no one single solution.

There are a range of possible pathways to Paris, and that range is fundamental to how we

Lightsource bp alone has 16 gigawatts in its pipeline – up from 9.8 gigawatts this time last year and just 1.6 gigawatts in 2018.

And, of course, we are now entering the offshore wind sector, which is growing faster than any other form of renewable energy.

I am really excited about the partnership we have agreed to create with Equinor. They are a world-class offshore wind company and we look forward to growing with them.

[PAUSE]

But let me be clear.

We know what happens when volume becomes more important than value.

And therefore we will only pursue opportunities that we believe can generate the disciplined returns we expect, and our shareholders expect.

And that links to the fourth question.

Can we deliver the 8-10% returns from renewables?

The answer is very simply – yes.

We actually believe we can do better, and these returns could turn out to be conservative. But let me take you through why we have absolute confidence in our plan.

It is firstly based on experience – specifically with Lightsource bp

Since we formed the partnership at the start of 2018, Lightsource bp has expanded its presence from 5 to 13 countries.

As I mentioned, it has grown its project pipeline from 1.6 gigawatts to 16.

And it has delivered 17 projects since 2018.

They typically achieve returns in the 8 to 10% range.

So how do <u>we</u> get to 8 to 10% across our renewables portfolio as a whole?

First, we know returns start at around 5 to 6% on an equity basis in a competitive auction.

Second, we believe that through our extensive experience in operations and project management – we can add value through applying our processes. We have track record here. For example in Biofuels – where we have, and more recently through bp Bunge, have increased the efficiency in harvesting by 50% since 2016.

Third, we'll integrate with the rest of bp. Through Trading where we have a long track record – over 30 years – of delivering close to a 2% return uplift. Or through the application of our digital expertise to drive additional performance. Or by bundling our renewables offer with different forms of energy along with our Natural Climate Solutions and offsets portfolio, to give customers what they want – clean, low cost and firm energy.

Fourth, we will use leverage which is typical in this industry.

The combination of these four areas gets us to 8-10%.

Beyond this – we have the choice to optimize the portfolio – to farm down or not – and if we do – that could add a further 1 to 2%.

So yes – we are confident we can deliver the returns we are targeting.

Now the fifth and final question – why bp? What is our competitive advantage – really?

Especially in this new world.

And there are four reasons:

First – our strong track record in operations and project management.

Second – our focus on relationships and partnerships around the world,

Third – our approach to digital and how we are using it to drive cost benefits and generate incremental value

Fourth – integration, and specifically our ability to integrate at a global level and across energy vectors.

Starting with operations and project management.

Today we are strong in oil and gas, strong in refining and have demonstrated how many of these technical skills are transferable.

We have an exceptional global project management organisation – top https://www.adb.org/news/speeches/asia-clean-energy-forum-2021-masatsugu-asakawa

Asia Clean Energy Forum 2021 - Masatsugu Asakawa

Speech | 15 June 2021

Opening remarks by Masatsugu Asakawa, President, Asian Development Bank, at the Asia Clean Energy Forum 2021, 15 June 2021

Introduction

Ladies and gentlemen, greetings.

On behalf of the Asian Development Bank, welcome to the Asia Clean Energy Forum 2021. We are happy to see that over 3,000 participants have joined this online gathering, our 16th Forum since 2006.

Our theme this year is *Accelerating the Low Carbon Transition in Asia and the Pacific*. Twelve years since ADB's clean energy program started, it is even more relevant today.

I. The urgent need for climate action

My friends, as our region confronts and recovers from the coronavirus disease (COVID-19) pandemic, we must not lose sight of the continued need to promote sustainable development while also taking action on global climate change, which remains the existential challenge of our time.

Asia and the Pacific must take its place at the front lines of this effort. The region, which now accounts for 36% of global GDP, has made great progress in economic development and poverty reduction. But it is also responsible for around 80% of the world's coal consumption, and up to 60% of CO_2 emissions. Many countries have also experienced the devastating consequences of climate change: floods, droughts, heat waves, and storms.

Now is the time for bold action. We must commit wholeheartedly to fighting climate change, including meeting the emission-reduction goals under the Paris Agreement—all while promoting economic growth and putting the region's development on a green path.

In the energy sector, we need to make major changes. These include:

- Avoiding the use of fossil fuels and switching to low-carbon fuels;
- Deploying more renewable energy;
- Improving energy efficiency;
- Reducing final energy demand; and
- Incentivizing investment in low-carbon technologies.

Making these changes will prove challenging. The pace and scale of the energy transition for countries in Asia and the Pacific will vary significantly.

Broad commitment across the region, along with tailored, country-level support from development partners, will be needed to meet the goal of limiting global warming to no more than 2 degrees above pre-industrial levels. Moreover, the pandemic has impeded the progress on sustainable and equitable growth.

We need to get back on the path to low-carbon sustainable development. In addition, we have to balance climate mitigation and adaptation efforts. And we must ensure universal energy access, as more than 200 million people in the region still have no electricity.

This effort must include addressing the special challenges of disadvantaged communities and the need of women for modern, clean, and affordable energy, and for sustainable livelihood.

II. ADB's support for global commitments to bold climate actions

In spite of the current situation, there is a path to addressing these challenges successfully. Let me describe this path and how ADB stands in full support of efforts to make it a reality.

Global action to achieve net zero emissions by around mid-century has gained momentum over the past year. Among the countries that have pledged carbon-neutrality are the People's Republic of China, Fiji, Japan, the Republic of Korea, Maldives, the Marshall Islands, Singapore, and Timor-Leste.

This November, the 26th Conference of the Parties (COP26) will convene in Glasgow. More countries are expected to submit more ambitious nationally determined contributions or NDCs, and to signify their commitment to carbon-neutrality.

ADB is ready to take on a leadership role in Asia and the Pacific in meeting these commitments.

We aim at stepping up our climate finance and capacity-building efforts to help our developing member countries (DMCs) achieve their NDCs.

Under our Strategy 2030, our target is to focus 75% of ADB's operations on climate adaptation and mitigation. We will also provide at least $80 billion in climate financing from 2019 to 2030, which means on average about $6.6 billion annually.

Due to the need to address the impact of the pandemic, our climate financing last year was about $4.3 billion. This year, we are confident that we will be able to provide over $6 billion for climate mitigation and adaptation through measures including investing in clean energy, as we did in 2019 when ADB provided in total $6.5 billion for climate finance.

ADB will contribute to the global effort envisioned by COP26 on multiple fronts. This includes promoting greater collaboration and cooperation; balanced climate mitigation and adaptation efforts; and a holistic approach that integrates the ecological, social, and financial aspects of resilience across our operations. And we are aligning our operations to support the targets of the Paris Agreement.

We will also continue to utilize our private sector operations, which will be pivotal to filling investment gaps and spearheading technological and business innovation in the pursuit of sustainable solutions.

III. Innovative technologies to support clean energy development

I want to emphasize here that the energy transition requires comprehensive long-term planning combined with effective innovations. ADB is committed to helping our DMCs as they formulate and implement technology roadmaps to achieve their NDCs.

ADB's support is taking full advantage of major technology advances that have slashed the costs of producing renewable energy—by up to 80% in the case of solar photovoltaics. Emerging technologies like smart grids, energy storage, and hydrogen are making it easier to integrate renewable energy into power networks and distributed energy systems. Smart technologies have enhanced the flexibility and resilience of power networks. Digitalization has also boosted energy efficiencies on the demand side.

Let me offer some examples of innovative energy projects we are supporting that reflect synergy between the public and private sector and have cross-sectoral impact:

- We approved $8 million grant for our first energy sector project in Kiribati, the South Tarawa Renewable Energy Project involving the installation of climate-resilient solar power capacity on a water reserve. The project design includes rainwater collection as an adaptation measure to deal with extreme weather, and a tree planting program for protection of the water reserve.
- We provided long-term financing in Thailand for a 10-megawatt (MW) wind power project with an integrated 1.88 megawatt-hour (MWh) pilot battery energy storage system. This is the first private sector project in the country to integrate utility-scale wind power generation with battery energy storage.
- Our $100 million loan for the First Utility-Scale Energy Storage Project in Mongolia will increase renewable energy use by providing a large energy reserve, load shifting capacity, and emergency back-up. This will help with Mongolia's decarbonization of its heavily coal-dependent energy system.

IV. A new ADB Energy Policy for a changing energy landscape

Last, let me note that we are reviewing ADB's Energy Policy in light of the profound changes the region faces in the energy landscape since the current policy was formulated in 2009. We have been consulting stakeholders since last year and plan to update our Energy Policy by the end of 2021.

We envision an Energy Policy that is aligned with our Strategy 2030 as well as global commitments under the Paris Agreement. ADB's new policy will be responsive to the needs of our DMCs as they build sustainable and resilient energy systems. While the final decision will have to be made by our Board, we are also aiming for a formal withdrawal from financing new coal-fired power generation.

V. Closing

Let me close by thanking our co-organizers, the United States Agency for International Development and the Korea Energy Agency, for their continuing support of this Forum.

I would also like to thank Mr. Alok Sharma, the President-Designate of COP26, for his contribution to ACEF 2021 following his participation in ADB's briefing to the board and Annual Meeting. He comes with an urgent message, which he has been articulating in various fora: that we must all act now to get the world on track to meet the goals of the Paris Agreement.

Allow me as well to acknowledge the leading role that the United Kingdom is taking in promoting global action on climate change at this critical time.

Finally, I wish to thank all of you for participating in this year's Forum. You are the communities of collaboration that our region needs to make our energy cleaner to ensure green, sustainable development in Asia and the Pacific.

I wish you a productive ACEF 2021.

THE INVESTMENT FUNDS INSTITUTE OF CANADA | L'INSTITUT DES FONDS D'INVESTISSEMENT DU CANADA

IFIC Monthly Investment Fund Statistics – May 2021

Mutual Fund and Exchange-Traded Fund Assets and Sales

June 17, 2021 (Toronto) – The Investment Funds Institute of Canada (IFIC) today announced investment fund net sales and net assets for May 2021.

Mutual fund assets totalled $1.896 trillion at the end of May 2021. Assets increased by $13.2 billion or 0.7% compared to April 2021. Mutual funds recorded net sales of $8.4 billion in May 2021.

ETF assets totalled $297.4 billion at the end of May 2021. Assets increased by $9.5 billion or 3.3% compared to April 2021. ETFs recorded net sales of $7.6 billion in May 2021.

Mutual Fund Net Sales/Net Redemptions ($ Millions)*

Asset Class	May 2021	Apr. 2021	May 2020	YTD 2021	YTD 2020
Long-term Funds					
Balanced	4,243	4,567	(740)	31,522	(7,202)
Equity	3,266	3,612	297	22,129	1,673
Bond	1,093	1,396	1,827	8,218	1,638
Specialty	345	439	447	2,533	2,436
Total Long-term Funds	8,948	10,014	1,832	64,403	(1,455)
Total Money Market Funds	(561)	(965)	817	(5,060)	5,394
Total	8,386	9,049	2,649	59,343	3,939

Mutual Fund Net Assets ($ Billions)*

Asset Class	May 2021	Apr. 2021	May 2020	Dec. 2020
Long-term Funds				
Balanced	933.4	924.9	788.6	874.4
Equity	662.1	658.5	501.4	593.4
Bond	254.3	252.9	221.3	246.4
Specialty	18.0	17.6	28.2	35.0
Total Long-term Funds	1,867.8	1,853.9	1,539.5	1,749.3
Total Money Market Funds	28.5	29.2	37.5	34.4
Total	1,896.3	1,883.1	1,576.9	1,783.7

* Please see below for important information regarding this data.

ETF Net Sales/Net Redemptions ($ Millions)*

Asset Class	May 2021	Apr. 2021	May 2020	YTD 2021	YTD 2020
Long-term Funds					
Balanced	284	339	73	2,008	831
Equity	3,797	2,812	1,873	15,360	12,768
Bond	1,751	1,617	(56)	6,799	2,418
Specialty	1,941	1,430	335	5,120	901
Total Long-term Funds	7,773	6,198	2,225	29,287	16,918
Total Money Market Funds	(177)	(665)	402	(1,676)	1,590
Total	7,596	5,533	2,627	27,611	18,508

ETF Net Assets ($ Billions)*

Asset Class	May 2021	Apr. 2021	May 2020	Dec. 2020
Long-term Funds				
Balanced	9.7	9.3	5.4	7.2
Equity	188.6	182.3	127.6	158.4
Bond	84.1	82.0	68.2	79.3
Specialty	9.5	8.6	4.1	5.2
Total Long-term Funds	291.9	282.2	205.3	250.0
Total Money Market Funds	5.6	5.8	6.1	7.3
Total	297.4	288.0	211.4	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.

*** 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:

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416-309-2317

Dennis Gartman’s Rules of Trading Early 2010s

NEVER, EVER, EVER ADD TO A LOSING POSITION: EVER!: Adding to a losing position eventually leads to ruin, remembering Enron, Long Term Capital Management, Nick Leeson and myriad others.

TRADE LIKE A MERCENARY SOLDIER: As traders/investors we are to fight on the winning side of the trade, not on the side of the trade we may believe to be economically correct. We are pragmatists first, foremost and always.

MENTAL CAPITAL TRUMPS REAL CAPITAL: Capital comes in two forms... mental and real... and defending losing positions diminishes one’s finite and measurable real capital and one’s infinite and immeasurable mental capital accordingly and alway.

WE ARE NOT IN THE BUSINESS OF BUYING LOW AND SELLING HIGH: We are in the business of buying high and selling higher, or of selling low and buying lower. Strength begets strength; weakness more weakness.

IN BULL MARKETS ONE MUST TRY ALWAYS TO BE LONG OR NEUTRAL: The corollary, obviously, is that in bear markets one must try always to be short or neutral. There are exceptions, but they are very, very rare.

"MARKETS CAN REMAIN ILLOGICAL FAR LONGER THAN YOU OR I CAN REMAIN SOLVENT:" So said Lord Keynes many years ago and he was... and is... right, for illogic does often reign, despite what the academics would have us believe.

BUY THAT WHICH SHOWS THE GREATEST STRENGTH; SELL THAT WHICH SHOWS THE GREATEST WEAKNESS: Metaphorically, the wettest paper sacks break most easily and the strongest winds carry ships the farthest,fastest.

THINK LIKE A FUNDAMENTALIST; TRADE LIKE A TECHNICIAN: Be bullish... or bearish... only when the technicals and the fundamentals, as you understand them, run in tandem.

TRADING RUNS IN CYCLES; SOME GOOD, MOST BAD: In the “Good Times” even one’s errors are profitable; in the inevitable “Bad Times” even the most well researched trade shall goes awry. This is the nature of trading; accept it and move on.

KEEP YOUR SYSTEMS SIMPLE: Complication breeds confusion; simplicity breeds elegance and profitability.

UNDERSTANDING MASS PSYCHOLOGY IS ALMOST ALWAYS MORE IMPORTANT THAN UNDERSTANDING ECONOMICS: Or more simply put, "When they’re cryin’ you should be buyin’ and when they’re yellin’ you should be sellin’!"

REMEMBER, THERE IS NEVER JUST ONE COCKROACH: The lesson of bad news is that more shall follow... usually hard upon and always with worsening impact.

BE PATIENT WITH WINNING TRADES; BE ENORMOUSLY IMPATIENT WITH LOSERS: Need we really say more?

DO MORE OF THAT WHICH IS WORKING AND LESS OF THAT WHICH IS NOT: This works well in life as well as trading. If there is a “secret” to trading... and to life... this is it.

CLEAN UP AFTER YOURSELF: Need we really say more? Errors only get worse.

SOMEONE’S ALWAYS GOT A BIGGER JUNK YARD DOG: No matter how much “work” we do on a trade, someone knows more and is more prepared than are we... and has more capital!

PAY ATTENTION: The market sends signals more often than not missed and/or disregarded... so pay attention!

WHEN THE FACTS CHANGE, CHANGE! Lord Keynes... again... once said that “ When the facts change, I change; what do you do, Sir?” When the technicals or the fundamentals of a position change, change your position, or at least reduced your exposure and perhaps exit entirely.

ALL RULES ARE MEANT TO BE BROKEN: But they are to be broken only rarely and true genius comes with knowing when, where and why!

https://www.scmp.com/economy/china-economy/article/3136092/chinas-three-child-policy-why-was-it-introduced-and-what-does

Explainer |

China's three-child policy: why was it introduced and what does it mean?

- China's one-child policy started in 1980 and was strictly enforced before it was officially ended in January 2016 in favour of a two-child policy
- Responding to its 2020 census results, China introduced a three-child policy in May 2021 after Chinese mothers gave birth to just 12 million babies in 2020

Andrew Mullen

+ FOLLOW

Published: 12:30am, 5 Jun, 2021

The National Bureau of Statistics (NBS) said Chinese mothers gave birth to 12 million babies in 2020, down from 14.65 million in 2019, marking an 18 per cent decline year on year. Photo: EPA-EFE

What is China's three-child policy?

On May 31, 2021, China's Communist Party Politburo meeting, chaired by President Xi Jinping, announced it will allow each couple in the country to

have up to three children
in a marked departure from its previous two-child limit.

A statement released after the meeting said major steps were needed to address the deepening problem of the

ageing population.

"Birth policies will be further improved. A policy that allows a couple to have three children will be introduced with supporting measures," it said.

"This will improve the population structure of China."

China expands two-child policy to three

China expands two-child policy to three

Why did China change its birth policy in 2021?

According to the national census conducted at the end of 2020, China's overall population

rose to 1.412 billion in 2020,
 from 1.4 billion a year earlier.

The National Bureau of Statistics (NBS) said Chinese mothers gave birth to 12 million babies in 2020, down from 14.65 million in 2019, marking an 18 per cent decline. This represented the fourth consecutive drop in the annual birth rate.

Is there a crisis brewing in the world's most populated country?
Get the full picture

China's fertility rate was 1.3 children per woman – below the replacement level of 2.1 needed for a stable population.

The NBS added that the average number of children that a Chinese woman said they were willing to have last year was 1.8.

The annual growth rate was 0.53 per cent for the period from 2010 to 2020, the slowest of any decade since China's first census in 1953. It was down by 0.04 percentage points compared with the average growth rate of 0.57 per cent from 2000 to 2010, according to the NBS.

Before the release of the census data, four researchers from China's central bank had already

called for Beijing to immediately liberalise its birth policies
 or face a scenario in which it has a lower share of workers and higher burden of elderly care than the United States by 2050.

What was the reaction to China's three-child policy?

An online survey
 conducted soon after the change was announced suggested it will be a hard sell: 90 per cent of respondents said they "would not consider" having three children.

State News Agency Xinhua polled 31,000 people, finding just 1,443 of them were "ready" to have a third child. It was "on the agenda" for 213 respondents, while 828 were "hesitant". The poll results, though, disappeared not long after they were posted.

A report by demographers at Renmin University of China backed up the sentiment as they estimated that the policy would lead to an annual increase of 200,000 to 300,000 births in the next five years – a slight increase from the rate of 12 million births last year.

For China's new 'lying flat' generation, the three-child policy may have little appeal, but for others, it may have some tractionHu Xingdou

Hu Xingdou, an independent political economist in Beijing, said young Chinese were unlikely to want to have bigger families.

"For China's new

'lying flat' generation

, the three-child policy may have little appeal, but for others, it may have some traction," Hu said.

"The government should work hard to relieve the burden of education, of housing among other things to improve people's willingness [to have more children]."

How has China's birth policy evolved?

China's one-child policy
 started in 1980 and was strictly enforced by the National Health and Family Planning Commission, with punishments including fines for violators and often forced abortions.

It restricted most couples to only a single offspring, and for years authorities argued it was a key factor in supporting the country's economic boom.

Civil servants and employees of government-affiliated organisations, including universities, risked losing their jobs if they were found to have had more than one child.

If parents did not pay a fine, second children could not be registered in the national household system, or hukou, meaning they did not exist legally and so would not have access to social services like health care and education.

National Health and Family Planning Commission spokesman Mao Qunan said the agency's work had reduced the number of births in China over the years by "400 million".

The one-child policy was generally accepted to mean one birth per family, so if women gave birth to two or more children at the same time, they would not be penalised.

Various reports in Chinese and international media suggested that this loophole led mothers to take fertility drugs to have multiple births.

China 2020 census records slowest population growth in decades

China officially ended its one-child policy on January 1, 2016, with the signing into law of a bill allowing all married couples to have a second child as it attempted to cope with an ageing population and shrinking workforce.

In March 2018, the new National Health Commission also took over responsibility for population management from the National Health and Family Planning Commission.

At the time, officials said the phrase "family planning" would disappear from the ministerial lexicon as China grappled with its shrinking labour pool and rapidly ageing population.

What is the outlook for China's birth policy?

A lack of affordable childcare,
 rising living costs and gruelling work hours has been cited as some of the reasons making many young Chinese think twice about having any children, let alone more than one.

In its most recent estimate in November 2020, the government said it expected China's population to peak in 2027.

But He Yafu, an independent expert on China's demographics, expects the population to start to fall in 2022 as the number of births drops to nearly 10 million and the number of deaths surpasses 10 million.

There had already been signs that China's national birth rate and population were on the verge of falling, with some experts warning of grave consequences.

Beijing, which has a population of around 21 million, suffered a 24.3 per cent decline in its birth rate in 2020 compared with a year earlier, according to official data.

China also saw 10.035 million

new registered births
 in the household registration system in 2020, down from 11.79 million in 2019, although this figure does not include the entire population.

Dan Tsubouchi @Energy_Tidbits · 2h

first sightings of the 2021 elk calves in #Canmore. it's always great to see the new borns each year

3

Dan Tsubouchi @Energy_Tidbits · 15h

And TV coverage included him finally. @MacHughesGolf drains long eagle on 13 to go -4 and 2nd overall. 🇨🇦

> **U.S. Open (USGA)** @usopengolf · 15h
>
> Well that looks familiar...🤔
>
> @MacHughesGolf | #USOpen
>
> This video is not available in your location.

2 6

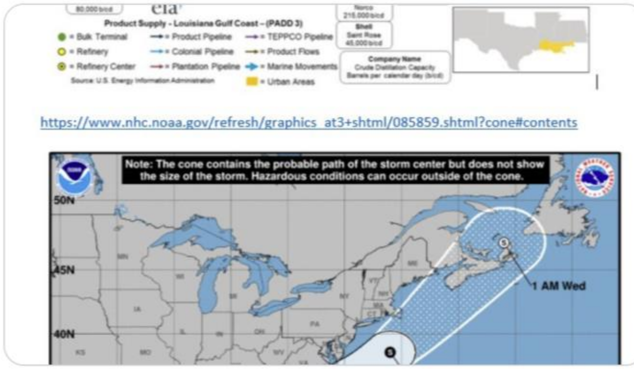
Dan Tsubouchi @Energy_Tidbits · Jun 19

Wow, can you imagine being in Ferenc Puskás Stadium right now. Hungary just scored in 1st half extra time to take a 1-0 lead over France? full crowd going crazy, it must be amazing. its going to be a not miss 2nd half. #Euro2020

4 1 3

Dan Tsubouchi @Energy_Tidbits · Jun 19

#TropicalStormClaudette making landfall at 45mph strength, but moving at a decent speed of 12 mph so hopefully any flash flooding is limited. Right at New Orleans refinery alley. Thx @EIAgov @NHC_Atlantic #OOTT #NatGas



1 1

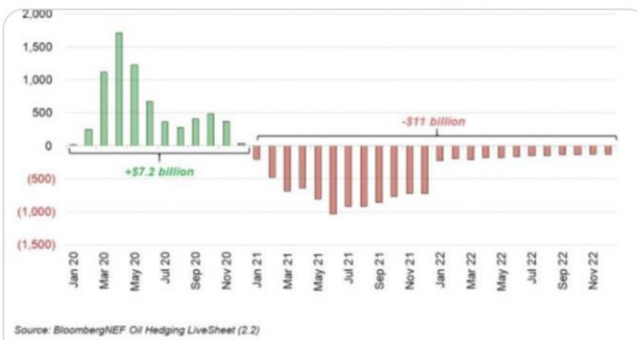
Dan Tsubouchi @Energy_Tidbits · Jun 18

anyone else watching the afternoon flight at @usopengolf and notice TV coverage showing about every other country golfers except 🇨🇦? have had it on for the afternoon flight and haven't seen @MacHughesGolf even though he is -3 today and -1 overall thru 12.

1 1

Dan Tsubouchi @Energy_Tidbits · Jun 18

Why more #Oil growth in 22. Hedge losses in 2021/hedges roll off for 2022. Another 3-6 mths of strong oil & stock prices & protected dividends, E&P will be still be cashed up & investors won't object to moving off Covid survival plans & more capital allocation to drilling. #OOTT



Pricing as of June 17, 2021

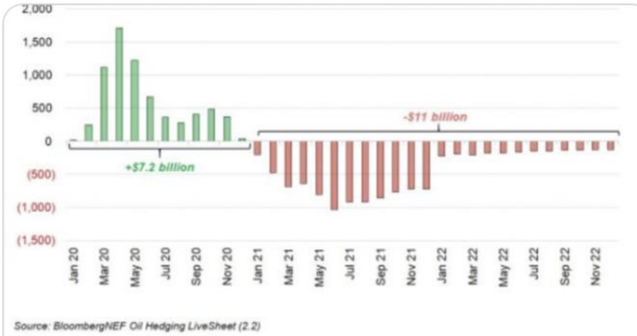
Reuters @Reuters · Jun 18

EXCLUSIVE OPEC told to expect limited U.S. oil output growth, for now - sources reut.rs/3vIE3rX

3 2

Dan Tsubouchi @Energy_Tidbits · Jun 18

Big US producer stocks generally +50% in 2021 and in strong financial position. Imagine when hedges roll off and oil is $70 or even $60. @BloombergNEF est. 42 US public #Oil producers hedge fund losses now $11b. Thx dadkins10@bloomberg.net #OOTT



Pricing as of June 17, 2021

3 3

Dan Tsubouchi @Energy_Tidbits · Jun 18

#InternationalSushiDay, place to go in #Calgary is Sushi Bar Zipang. we get the his Nigiri Blue Fin Tuna almost every week, its the best. And if you want a reminder of growing up, you can ask Naoya for off the menu Onigiri (rice balls).

zipang.ca

1 2

Dan Tsubouchi @Energy_Tidbits · Jun 18

3/3. #LNGSupplyGap in 2020s = need brownfield #LNG FIDs especially with delays to ~5 bcf/d of Mozambique LNG. See SAF Group Apr 28/2021 blog "Multiple Brownfield LNG FIDs Now Needed To Fill New LNG Supply Gap From Mozambique Chaos? How About LNG Canada Phase 2?" #NatGas

SAF GROUP

Blog Summary

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

Posted Wednesday April 28, 2021. 9:00 MT

The next six months will determine the size and length of the new LNG supply gap that is hitting harder and faster than anyone expected six months ago. Optimists will say the Mozambique government will bring sustainable security and safety to the northern Cabo Delgado province and provide the confidence to Total to quickly get back to LNG development such that its LNG in-service delay is a matter of months and not years. We hope so for Mozambique's domestic situation, but will it be that easy for Total's board to quickly look thru what just happened? Total suspended LNG development for 3 months, restarted development on March 25, but then 3 days of violence led it to suspend development again on March 28, and announce force majeure on Monday April 26. Even if the optimists are right, Mozambique LNG is counted on for LNG supply and the major LNG supply project that are in LNG supply forecasts are now all delayed – Total Phase 1 of 1.7 bcf/d and its follow on Phase 2 of 1.3 bcf/d, and Exxon's 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

1 3

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Dan Tsubouchi @Energy_Tidbits · Jun 18

2/3. Little lower, but close enough to SAF Group Oct 23, 2019 blog "Finally, Some Visibility That India Is Moving Towards Its Target For Natural Gas To Be 15% Of Its Energy Mix By 2030" forecast India #NatGas demand 24.0 bcf/d in 2030 ... #LNG

SAF GROUP

Excerpt from SAF Group Oct 23, 2019 Blog http://www.safgroup.ca/insights/trends-in-the-market/

Finally, Some Visibility That India Is Moving Towards Its Target For Natural Gas To Be 15% Of Its Energy Mix By 2030

Posted: Wednesday October 23, 2019. 3:45pm MT

Hitting 15% of its energy mix would increase India's natural gas consumption by >1.5 bcf/d per year. We projected how much India's natural gas consumption would increase if it can hit its target of 15% of total energy mix in 2030. BP data shows India's natural gas consumption in 2018 was 5.6 bcf/d and natural gas was only 6.2% of total energy mix. BP also estimates India's total energy consumption grew at a rate of 5.2% per year for the 2007 – 2017 period, but energy consumption growth increased to +7.9% in 2018 YoY vs 2017 But if we only assume a 5% growth in total energy mix to 2030, then if natural gas is 15% of India's energy mix, it would be 18.8 bcf/d in 2025 and 24.0 bcf/d in 2030 ie. growth of +13.2 bcf/d to 2025 and +18.4 bcf/d to 2030. India's domestic natural gas production peaked in 2010 at 4.6 bcf/d, but has been flat from 2014 thru 2018 at +/- 2.7 bcf/d. We expect there to be some increased focus to at least return India to modest domestic natural gas production. But, until then, any growth in natural gas consumption will be met with LNG. Our model forecasts of >1.5 bcf/d per year, on average, in consumption is the equivalent of 2.5 Cheniere LNG trains per year.

India's Projected Natural Gas Consumption @15% Of Energy Mix (bcf/d)

1 2

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Dan Tsubouchi @Energy_Tidbits · Jun 18

1/3. #LNGSupplyGap is coming in 2020s. #Petronet reminds India target #NatGas to be 15% of energy mix by 2030. Means consumption 5.5 to 22.6 bcf/d, #LNG imports <3 to 15.8 bcf/d in 2030. Assumes India can reverse declining production and can grow <3 to 6.8 bcf/d, Hmm! ...

https://www.thehindubusinessline.com/companies/lngs-share-of-indian-gas-demand-to-rise-to-70-by-2030-petronet-ceo/article34845886.ece

LNG's share of Indian gas demand to rise to 70% by 2030: Petronet CEO

Reuters NEW DELHI | Updated on June 18, 2021

Replacing about 30% of the country's crude oil imports with LNG would save $10 billion at current global oil price of $74/barrel, he said

The share of liquefied natural gas (LNG) in India's gas consumption could rise to 70% from the current 50% in 10 years, and new import terminals are needed, the chief executive of the country's top gas importer said.

Prime Minister Narendra Modi has set a target to raise the share of natural gas in the country's energy mix to 15% by 2030 from the current 6.3% to cut its carbon footprint.

To meet that target India's gas consumption needs to rise to 640 million standard cubic metres a day (mmscmd) from the current 155 mmscmd, AK Singh, chief executive of Petronet LNG, said at ET Energy Leadership summit.

Huge invesments by Indian cos

Indian companies are investing billions of dollars to strengthen gas infrastructure, including laying 15,000-kilometer pipelines to supply cleaner fuel to households and industries. India currently has

2 2 4

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Dan Tsubouchi @Energy_Tidbits · Jun 18

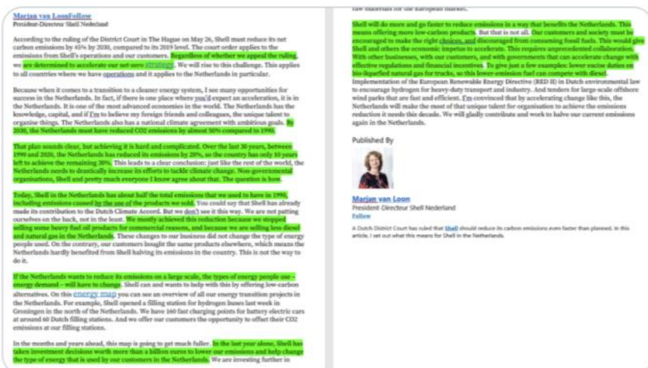
Expected #TropicalStorm strength on landfall early Sat am right at #Oil refinery alley New Orleans. Reminder flooding tends to be bigger impact than wind, moving fast at 14 mph so hopefully doesn't dump too much water. A few offshore platforms being evacuated. #OOTT #NatGas

https://www.nhc.noaa.gov/refresh/graphics_at3+shtml/085605.shtml?cone#contents

1 · 2

Dan Tsubouchi @Energy_Tidbits · Jun 17

#Shell to accelerate #NetZero strategy "regardless of whether we appeal" Dutch ruling. Hmmm! need "effective regulations and financial incentives" for economic impetus to accelerate ie. #EnergyTransition isn't cost competitive so power will cost more. #NatGas #OOTT



Marjan van LoonFollow
President-Directeur Shell Nederland

According to the ruling of the District Court in The Hague on May 26, Shell must reduce its net carbon emissions by 45% by 2030, compared to its 2019 level. The court order applies to the emissions from Shell's operations and our customers. Regardless of whether we appeal the ruling, we are determined to accelerate our net zero strategy. We will rise to this challenge. This applies to all countries where we have operations and it applies to the Netherlands in particular.

Because when it comes to a transition to a cleaner energy system, I see many opportunities for success in the Netherlands. In fact, if there is one place where you'd expect an acceleration, it is in the Netherlands. It is one of the most advanced economies in the world. The Netherlands has the knowledge, capital, and if I'm to believe my foreign friends and colleagues, the unique talent to organise things. The Netherlands also has a national climate agreement with ambitious goals. By 2030, the Netherlands must have reduced CO2 emissions by almost 50% compared to 1990.

That plan sounds clear, but achieving it is hard and complicated. Over the last 30 years, between 1990 and 2020, the Netherlands has reduced its emissions by 20%, so the country has only 10 years left to achieve the remaining 30%. This leads to a clear conclusion: just like the rest of the world, the Netherlands needs to drastically increase its efforts to tackle climate change. Non governmental organisations, Shell and pretty much everyone I know agree about that. The question is how.

Today, Shell in the Netherlands has about half the total emissions that we used to have in 1990, including emissions caused by the use of the products we sold. You could say that Shell has already made its contribution to the Dutch Climate Accord. But we don't see it this way. We are not patting ourselves on the back, not in the least. We mostly achieved this reduction because we stopped selling some heavy fuel oil products for commercial reasons, and because we are selling less diesel and natural gas in the Netherlands. These changes to our business did not change the type of energy people used. On the contrary, our customers bought the same products elsewhere, which means the Netherlands hardly benefited from Shell halving its emissions in the country. This is not the way to do it.

If the Netherlands wants to reduce its emissions on a large scale, the types of energy people use – energy demand – will have to change. Shell can and wants to help with this by offering low-carbon alternatives. On this energy map you can see an overview of all our energy transition projects in the Netherlands. For example, Shell opened a filling station for hydrogen buses last week in Groningen in the north of the Netherlands. We have 160 fast charging points for battery electric cars at around 60 Dutch filling stations. And we offer our customers the opportunity to offset their CO2 emissions at our filling stations.

In the months and years ahead, this map is going to get much fuller. In the last year alone, Shell has taken investment decisions worth more than a billion euros to lower our emissions and help change the type of energy that is used by our customers in the Netherlands. We are investing further in

raw materials for the European market.

Shell will do more and go faster to reduce emissions in a way that benefits the Netherlands. This means offering more low-carbon products. But that is not all. Our customers and society must be encouraged to make the right choices, and discouraged from consuming fossil fuels. This would give Shell and others the economic impetus to accelerate. This requires unprecedented collaboration. With other businesses, with our customers, and with governments that can accelerate change with effective regulations and financial incentives. To give just a few examples: lower excise duties on bio-liquefied natural gas for trucks, so this lower-emission fuel can compete with diesel. Implementation of the European Renewable Energy Directive (RED II) in Dutch environmental law to encourage hydrogen for heavy-duty transport and industry. And tenders for large-scale offshore wind parks that are fast and efficient. I'm convinced that by accelerating change like this, the Netherlands will make the most of that unique talent for organisation to achieve the emissions reduction it needs this decade. We will gladly contribute and work to halve our current emissions again in the Netherlands.

Published By

Marjan van Loon
President-Directeur Shell Nederland
Follow

A Dutch District Court has ruled that Shell should reduce its carbon emissions even faster than planned. In this article, I set out what this means for Shell in the Netherlands.

> **Dan Tsubouchi** @Energy_Tidbits · Jun 9
>
> 
>
> 1/4. Big news. #Shell expects to appeal but concedes to move on Dutch ruling to reduce net carbon emissions by 45% by 2030 v 2019 on worldwide basis. huge cuts needed. means "taking some bold but measured steps over the coming years"... #NatGas #OOTT...
>
> Show this thread

1 · 6

Dan Tsubouchi @Energy_Tidbits · Jun 17

yesterday we had the 2021 deer fawns. this morning the 2021 goslings with mom and dad. another great start to the day in #Calgary

Dan Tsubouchi @Energy_Tidbits · Jun 17

This is what is great about @EURO2020. not just great football so far but moving stock prices. wonder how much it would be worth to the footballer and to $KO stock if one of the top footballers at @EURO2020 pulled a Mean Joe Greene? youtube.com/watch?v=ITDFgs...

> **USA TODAY** @USATODAY · Jun 16
>
> Cristiano Ronaldo may have cost Coca-Cola billions after he moved two bottles from his press conference and replaced with water. bit.ly/3xqgc1z

1

Dan Tsubouchi @Energy_Tidbits · Jun 17

#321CrackSpread was $25 in May, now >$17. See below SAF Group transcript of @starfuels Matt Stanley not seeing support for forecasters 2nd half rhetoric on demand coming roaring back. Usual great podcast @gulf_intel @sean_evers #OOTT #Gasoline #JetFuel soundcloud.com/user-846530307...

SAF Group created transcript of excerpt from Gulf Intelligence New Silk Road "Live" Podcast June 17, 2021 https://soundcloud.com/user-846530307/podcast-daily-energy-markets-forum-new-silk-road-live-june-17th

Items in "italics" are SAF Group created transcript

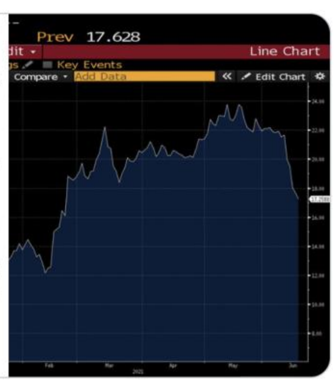
At 12:15 min mark.

Gulf Intelligence, Sean Evers Managing Partner. *"Matt, we touched nearly $75 a barrel yesterday, $74.96 was the high intraday trade. This market is trading on fundamentals as well. Ultimately, we saw a massive inventory draw over 7 million barrels, confirmed first by the API then by the EIA, the fundamentals are quite solid, OPEC still holding very tight reins."*

Matt Stanley, Director, Star Fuels (Dubai). *"yes, crude is drawing, stocks have been on a downward trajectory for awhile, but gasoline inventories are the highest since February. And if you want a bellweather for demand, lots of people will look at what's called the 3-2-1 crack in the US. That's 3 barrels of WTI in, 2 barrels of gasoline out and 1 diesel out. that's the lowest its been since February as well. That was trading $25 a barrel in May, its now trading just above $17. So yes, crude might be going places, but the same argument. Crude has to be burned and refined and consumed. In order for oil demand to look anything like the tangible, these forecasters, you know the second half rhetoric is all about demand is going to come roaring back. You look at real tangible data regarding demand and I can't see, I can't form that same argument for the second half rhetoric. You know his highness Sheik Maktoum, the chairman of Emirates Group on Tuesday, who's historically he's run a fantastic business for the last 30 years. the Emirates Group reported a $6 billion loss, wasn't surprising, most airlines have. But his outlook was not bullish. That hub and spoke model that Emirates have, is still in a perilous state. Of course, people are hoping that air travel is going to come back. I was talking to a friend last night, if you look at Asia and what's happening in Asia. China, Singapore, the [xxxx?] have got no interest in opening borders anytime soon. They are pursing this zero case agenda. That's completely up to them. But 5 million barrels of oil demand is still lacking from pre-pandemic. Half of that demand that is forecast to come back is jet fuel. So he told me, jet fuel demand into the EU is about 700,000 b/d. this year so far, its been about between 150 and 200. So I look at these data Sean and so yes, I see crude going places, I don't see the products that's being refined going anywhere close to what these forecasters are assuming its going."*

Sean Evers. *"Rustin pointed out yesterday that tanker rates are still way down and freight markets are not buying into yet there is a big wave of oil coming"*

Matt Stanley. *"boy, of course he's the one feeling the pinch because he works for one of the world's biggest shipping companies. So he's right. this is the irony. You've got more cargoes coming back with OPEC bringing back production and you've got a backwardated market, which out to on crude, I think its $3.60 until December. So if you put oil on a ship and store it as Vitol is doing off the coast of Southxxx in*



2 3

Dan Tsubouchi @Energy_Tidbits · Jun 16

Putin on #NorthernPassage. adding modern military & border infrastructure, "there are 1,000 nautical miles. This is our sovereign right to either let ships go through there or not, but we're not abusing this rule". Big ship/tanker value add during #SuezCanal shutdown. #OOTT #LNG

getting longer with warmer north. Huge savings, can shorten by >4,000 km and 14 days vs Suez Canal. #OOTT " Time is money and this is a huge savings in time and cost even if there could be added insurance costs in the northern route. We have to believe that the Suez Canal stoppage has got shippers thinking more about the utilization of Russia's Northern Sea Route. We noted in our Jan 24, 2021 Energy Tidbits that Russia will be attempting the earliest ever LNG shipment to Asia through the Northern Sea Route in May, as the transit season is getting longer for the NSR. The NSR is a much shorter route from Europe to Asia than through the Suez, with a trip from Hamburg to Yokohoma taking 14 days less using the NSR and is ~4,000 Nm shorter. Below is a good graphic from the ECORYS discussion paper at the International Transport Forum. [LINK]

Figure 33: Suez Canal vs. Northern Sea Route

Context for NSR utilization

Arctic sea ice

- Sea-ice decline has been faster during the past ten years than in the previous 20 years

Global trade flows

- In 1869 the Suez Canal opened and reduced shipping distances by 23%.
- Travelling on the NSR reduces travel times (with

2

Dan Tsubouchi @Energy_Tidbits · Jun 16

#Liberals hit @jkenney & Alberta #Coal. 06/11, impossible for new thermal #Coal plant. Today, hit coal exploration. Also preparing new regs on existing coal mine discharges, this feels like fits May 21 communique #G7 accepting accelerated moves will strand high carbon assets.

pt from https://www.g7uk.org/g7-climate-and-environment-ministers-communique/

G7 Climate and Environment: Ministers' Communiqué

blished 21 May 2021
nt commitments

, the G7 Ministers responsible for Climate and Environment, met virtually on 20 -21 May 2021.

ort-term action – building back better and more resilient through a net zero pathway

celerating the transformation of the global economy towards a net zero pathway will depend up curing a green, sustainable, resilient, inclusive and gender-responsive recovery from COVID-19 nanner consistent with the 2030 Agenda for Sustainable Development, leaving no one behind. celerate progress towards achieving our Paris Agreement goals, we need to harness the signifi portunities for sustainable development – including green jobs and sustainable, resilient growth making investments in the recovery from COVID-19 that are aligned with pathways towards ou pective enhanced Nationally Determined Contributions (NDCs) and 2050 net zero commitment ognising the risk of stranded assets associated with high carbon investments.

dium and long-term action – guided by net zero aligned NDCs and LTSs

highlight with deep concern the findings from the IPCC Special Report 2018, and recognise th ed to reduce the global level of annual GHG emissions to 25-30 Gt of carbon dioxide equivalent er by 2030 to put the world on track to limit global warming to 1.5°C above pre-industrial levels er to reduce the risk of catastrophic consequences of climate change. We commit to submitting g-term strategies (LTSs) that set out concrete pathways to net zero GHG emissions by 2050 as on as possible, making utmost efforts to do so by COP26. We commit to updating them regularl luding to reflect on the latest science, as well as technological and market developments. We a e with concern the initial version of the NDC Synthesis Report prepared by the UNFCCC cretariat which highlights that many parties are yet to submit new and updated NDCs. NDCs mmunicated by 2020 collectively fall far short of the ranges found in pathways identified by the CC, which limit global warming to 1.5°C or well below 2°C. We welcome the significantly enhanc bition reflected in 2030 targets announced by all G7 members, which put us on clear and credil hways towards our respective 2050 net zero GHG emission reduction targets. We note the portant contribution these commitments make towards keeping 1.5°C within reach and in provid unequivocal direction of travel for business, investors and society at large. Those of us who ha already done so commit to submitting our enhanced NDCs to the UNFCCC as soon as possib ad of COP26.

> **Dan Tsubouchi** @Energy_Tidbits · May 23
>
> More important to #Oil #NatGas co's in 2021 than @IEA #NetZero pathway? #G7 policymakers make new commitments on #EnergyTransition ie. regs/laws that are coming. Also warning needed acceleration to NetZero will lead to stranded #FossilFuels assets. #OOTT g7uk.org/g7-climate-and...

2 1

Dan Tsubouchi @Energy_Tidbits · Jun 16

For those not near their laptop, EIA weekly #Oil #Gasoline #Distillates inventory numbers out. Prior to release, WTI was $72.13 #OOTT

ir.eia.gov/wpsr/overview....

Oil/Products Inventory June 11: EIA, Bloomberg Survey Expectations, API			
(million barrels)	EIA	Expectations	API
Oil	-7.36	-2.50	-8.54
Gasoline	1.95	-1.00	2.85
Distillates	-1.02	0.50	1.96
	-6.43	-3.00	-3.73
Note:In addition, SPR draw of 0.9 mmb for June 11 week			
Note: Cushing had a draw of 2.15 mmb for June 11 week			
Source EIA, Bloomberg			
Prepared by SAF Group			

4

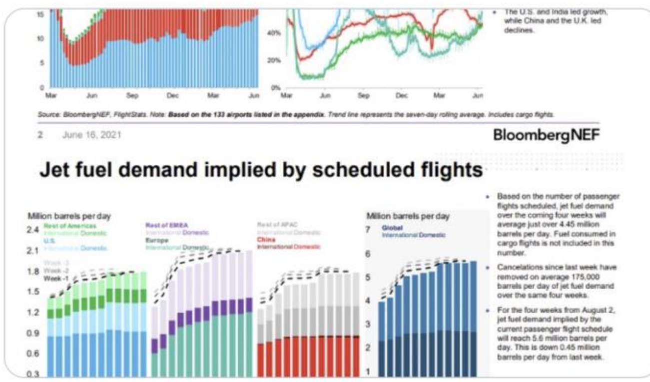
Dan Tsubouchi @Energy_Tidbits · Jun 16

now i know why the mama deer has been eating up our backyard in #Calgary, she has two newborn fawns. here they just left our place to our neighbours. they can't be more than a week or two old, what a great start to the day.

1 25

Dan Tsubouchi @Energy_Tidbits · Jun 16

Great weekly air travel/jet fuel data from @BloombergNEF ddoherty26@bloomberg.net. can see impact of increasing reopenings in May/June. Just think below #OilDemandSurge doesn't build in full recovery in jet fuel. #OOTT #Oil



> **Dan Tsubouchi** @Energy_Tidbits · Jun 16
>
> #OilDemandSurge. Thx @MoEnergy_Saudi Abdulaziz great job on #OPEC+ supply, the #Oil theme for rest of 2021 is the oil demand surge. @IEA OMR fcst Q3 demand +3.1 mmb/d QoQ & +6.0 mmb/d over Q2/Q3/Q4. @OPECSecretariat fcst Q3 demand +3.1 mmb/d QoQ & +6.45 mmb/d over Q2/Q3/Q4. #OOTT

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Dan Tsubouchi @Energy_Tidbits · Jun 16

#OilDemandSurge. Thx @MoEnergy_Saudi Abdulaziz great job on #OPEC+ supply, the #Oil theme for rest of 2021 is the oil demand surge. @IEA OMR fcst Q3 demand +3.1 mmb/d QoQ & +6.0 mmb/d over Q2/Q3/Q4. @OPECSecretariat fcst Q3 demand +3.1 mmb/d QoQ & +6.45 mmb/d over Q2/Q3/Q4. #OOTT

2 2

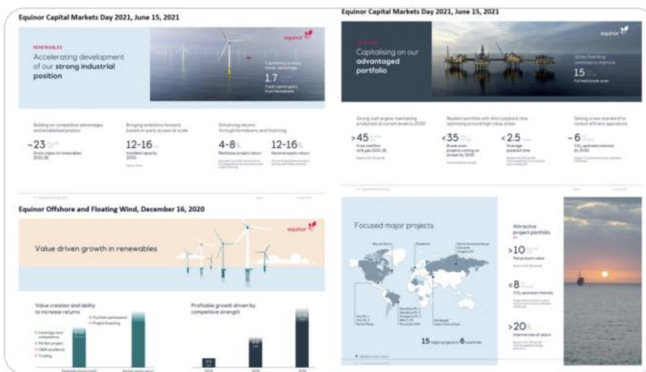
Dan Tsubouchi @Energy_Tidbits · Jun 15

just happened to peek out the window and see one of the local #Calgary deer having a big salad feast in our backyard. looks like she is enjoying the lunch

6

Dan Tsubouchi @Energy_Tidbits · Jun 15

Good thing #Equinor has #Oil #NatGas w/ ave payback time <2.5 yrs & >20% base IRRs as they lowered expected base returns (prior to farmdowns & project financing) from #Wind to 4-8% vs 6-10% in Dec. But didn't include average payback time for wind, Hmmm! #EnergyTransition #OOTT



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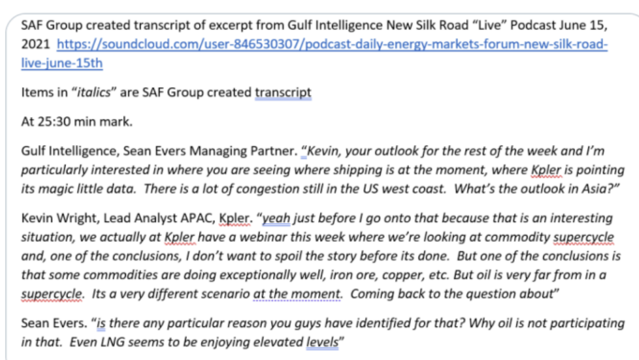
Dan Tsubouchi @Energy_Tidbits · Jun 15

#Oil not in #Supercycle as oil cycle is really based on constraint of supply by #OPEC+, @Kpler Kevin Wright. Maybe supercycle post Covid? if demand keeps growing & #Biden #Trudeau others permanently impact supply due to climate restrictions? Usual great podcast @sean_evers #OOTT



SAF Group created transcript of excerpt from Gulf Intelligence New Silk Road "Live" Podcast June 15, 2021 https://soundcloud.com/user-846530307/podcast-daily-energy-markets-forum-new-silk-road-live-june-15th

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

At 25:30 min mark.

Gulf Intelligence, Sean Evers Managing Partner. "*Kevin, your outlook for the rest of the week and I'm particularly interested in where you are seeing where shipping is at the moment, where Kpler is pointing its magic little data. There is a lot of congestion still in the US west coast. What's the outlook in Asia?*"

Kevin Wright, Lead Analyst APAC, Kpler. "*yeah just before I go onto that because that is an interesting situation, we actually at Kpler have a webinar this week where we're looking at commodity supercycle and, one of the conclusions, I don't want to spoil the story before its done. But one of the conclusions is that some commodities are doing exceptionally well, iron ore, copper, etc. But oil is very far from in a supercycle. Its a very different scenario at the moment. Coming back to the question about*"

Sean Evers. "*is there any particular reason you guys have identified for that? Why oil is not participating in that. Even LNG seems to be enjoying elevated levels*"

Kevin Wright. "*yeah, as I say its more about other commodities that are probably doing better relative to*

1 3 16

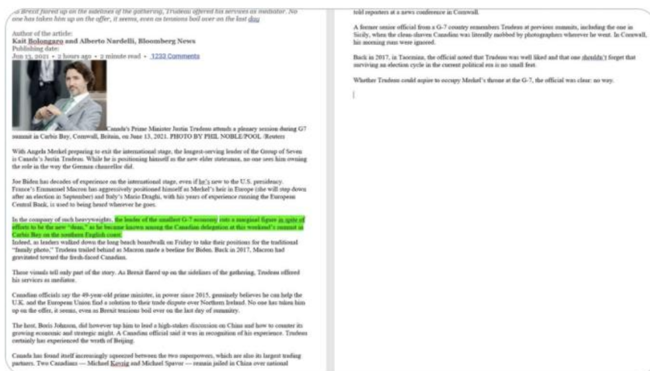
Dan Tsubouchi @Energy_Tidbits · Jun 14

Argentina/Chile @CopaAmerica today. Surely AR didn't think CL believed #7 De Paul would take the free kick instead of #Messi. Even still, Messi still scored. Not much @BNNBloomberg or @CNBC on in background after 9:45am MT with @CopaAmerica & @EURO2020 on all day.

1

Dan Tsubouchi @Energy_Tidbits · Jun 14

Silliness aside. G7 didn't buy #Trudeau is the dean, didn't deter #Liberals from trying. Won't matter more like #LarryFink warn #EnergyTransition aspirations not possible, won't deter #Liberals from trying to be more aggressive on emissions. #EnergyTransition will be costly #OOTT



As Brexit flared up on the sidelines of the gathering, Trudeau offered his services as mediator. No one has taken him up on the offer, it seems, even as tensions boil over on the last day

Author of the article:
Kait Bolongaro and Alberto Nardelli, Bloomberg News
Publishing date:
Jun 13, 2021 • 2 hours ago • 2 minute read • 1233 Comments

Canada's Prime Minister Justin Trudeau attends a plenary session during G7 summit in Carbis Bay, Cornwall, Britain, on June 13, 2021. PHOTO BY PHIL NOBLE/POOL /Reuters

With Angela Merkel preparing to exit the international stage, the longest-serving leader of the Group of Seven is Canada's Justin Trudeau. While he is positioning himself as the new elder statesman, no one sees him owning the role in the way the German chancellor did.

Joe Biden has decades of experience on the international stage, even if he's new to the U.S. presidency. France's Emmanuel Macron has aggressively positioned himself as Merkel's heir in Europe (she will step down after an election in September) and Italy's Mario Draghi, with his years of experience running the European Central Bank, is used to being heard wherever he goes.

In the company of such heavyweights, the leader of the smallest G-7 economy cuts a marginal figure in spite of efforts to be the new "dean," as he became known among the Canadian delegation at this weekend's summit in Carbis Bay on the southern English coast.
Indeed, as leaders walked down the long beach boardwalk on Friday to take their positions for the traditional "family photo," Trudeau trailed behind as Macron made a beeline for Biden. Back in 2017, Macron had gravitated toward the fresh-faced Canadian.

These visuals tell only part of the story. As Brexit flared up on the sidelines of the gathering, Trudeau offered his services as mediator.

Canadian officials say the 49-year-old prime minister, in power since 2015, genuinely believes he can help the U.K. and the European Union find a solution to their trade dispute over Northern Ireland. No one has taken him up on the offer, it seems, even as Brexit tensions boil over on the last day of summitry.

The host, Boris Johnson, did however tap him to lead a high-stakes discussion on China and how to counter its growing economic and strategic might. A Canadian official said it was in recognition of his experience. Trudeau certainly has experienced the wrath of Beijing.

Canada has found itself increasingly squeezed between the two superpowers, which are also its largest trading partners. Two Canadians — Michael Kovrig and Michael Spavor — remain jailed in China over national

told reporters at a news conference in Cornwall.

A former senior official from a G-7 country remembers Trudeau at previous summits, including the one in Sicily, when the clean-shaven Canadian was literally mobbed by photographers wherever he went. In Cornwall, his morning runs were ignored.

Back in 2017, in Taormina, the official noted that Trudeau was well liked and that one shouldn't forget that surviving an election cycle in the current political era is no small feat.

Whether Trudeau could aspire to occupy Merkel's throne at the G-7, the official was clear: no way.

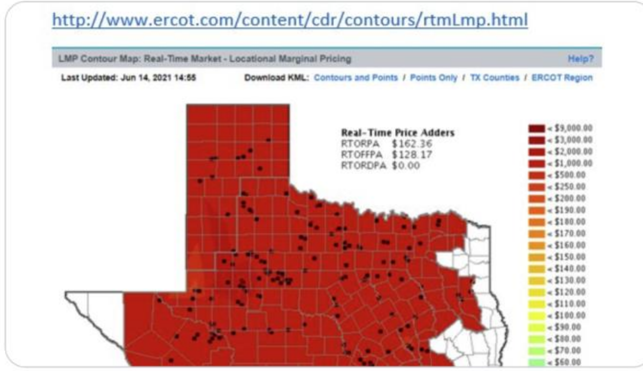
Dan Tsubouchi @Energy_Tidbits · Jun 6

ICYMI $BLK #LarryFink on #EnergyTransition "we're going to have much higher inflation because we do not have the technology to do all this". #EnergyTransition will take longer and cost more, also demise of #Oil #NatGas won't be as fast as expected #OOTT ...

1 2 1

Dan Tsubouchi @Energy_Tidbits · Jun 14

Still not at daily peak power demand, but Texas power reserve is getting smaller. and #Electricity prices are showing it. Mid to high 90's in many parts of Texas. Good test for #ERCOT power management before they see even hotter days. #NatGas



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Dan Tsubouchi @Energy_Tidbits · Jun 14

Bigger #LNGSupplyGap is coming. Reuters #Galp report fits SAF Apr 28 blog - $TOT Mozambique #LNG 1.7 bcf/d Phase 1 delay backs up #Exxon Rozuma LNG 2.0 bcf/d Phase 1. Brownfield LNG FIDs now needed ie. LNG Canada Phase 2? Think $TOU also believes this.
reuters.com/article/us-moz...


By Sergio Goncalves 3 MIN READ

LISBON (Reuters) - Portugal's Galp Energia, a partner in an Exxon Mobil-led gas consortium in Mozambique, will not invest in onshore plants there until authorities guarantee security and social stability, which may take time, CEO Andy Brown told Reuters.

The logo of GALP is seen next to a petrol station of GALP company near Lisbon, Portugal July 30, 2018. REUTERS/Rafael Marchante/Files

This marks a second setback to Mozambique's hopes to develop a major LNG gas hub in the coming years after TotalEnergies suspended its own, separate LNG project in the country.

Attacks by militants in northern Mozambique's Cabo Delgado region, near the $30 billion Rovuma liquefied natural gas project, have forced hundreds of thousands of people to flee the area.

The Mozambican government has said it expects the consortium to take the final investment decision, already postponed from 2020 due to the coronavirus pandemic, this year.

But the CEO of Galp, which has a 10% stake in the consortium, told Reuters on Monday his company did not include investments in Rovuma's onshore facilities in its net capital expenditure plan for the next five years.

"It means that at the moment it's very hard for us to predict when the time to invest will be," Brown said.

"Last year we were really planning to have built Rovuma by 2025 and I don't want to make a promise on Rovuma and then disappoint the market again," he said.

Exxon did not immediately respond to a request for comment and the other major partner, Italy's ENI, declined to comment.

"Before Galp starts investing in the project, the government needs to work with the local population to create the right kind of stability and social cohesion, as well as security, on the ground ... That may take a while," Brown said.

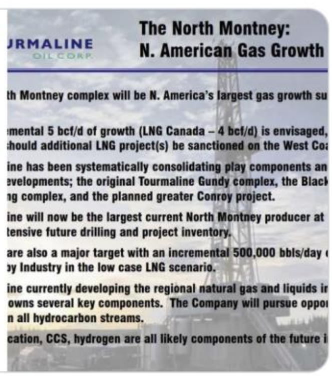
Brown said that once France's TotalEnergies, which stopped construction of a separate LNG project near Rovuma due to the latest attacks in March and is working with Mozambique to ensure stability in the area, has reliably resumed the works, "we will be in a position to consider our own project".

Despite the setbacks, Mozambique with its attractive gas projects is "a really important country for Galp", Brown said, and the consortium is "working to get the cost to a level where this project is really competitive".

Brown said that over the next five years, Brazil will absorb "the vast majority" of the 320 million to 400 million euros of net capex which Galp has allocated to upstream annually, while there will be "some investment in floating LNG in Mozambique and some small investments in Angola".

The investments in Brazil will be "mostly allocated to already sanctioned developments, including the Bacalhau I", he said.

Reporting by Sergio Goncalves; additional reporting by Stephen Jewkes and Jennifer Hiller; editing by Andrei Khalip and Jason Neely Our Standards: The Thomson Reuters Trust Principles.



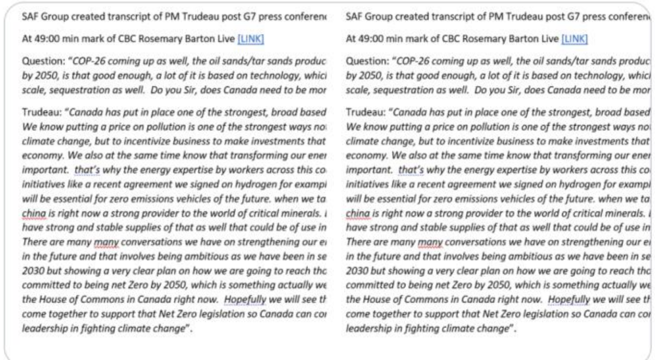
> **Dan Tsubouchi** @Energy_Tidbits · Apr 28
>
> 
>
> New blog was just posted to our SAF Group website. Multiple Brownfield LNG FIDs Now Needed To Fill New LNG Supply Gap From Mozambique Chaos? How About LNG Canada Phase 2? #LNG #NatGas #AECO #OOTT
> ...

1 3

Dan Tsubouchi @Energy_Tidbits · Jun 13

#OilSands. Note #Trudeau wouldn't even acknowledge the oil sands pathways to net zero, or say positive move but need to do more or move faster. not a good sign. have to worry it links to prior tweet #G7 May 21 warning re stranded assets risk. #OOTT

newswire.ca/news-releases/...



SAF Group created transcript of PM Trudeau post G7 press conferen

At 49:00 min mark of CBC Rosemary Barton Live [LINK]

Question: *"COP-26 coming up as well, the oil sands/tar sands produc by 2050, is that good enough, a lot of it is based on technology, whic scale, sequestration as well. Do you Sir, does Canada need to be mor*

Trudeau: *"Canada has put in place one of the strongest, broad based We know putting a price on pollution is one of the strongest ways no climate change, but to incentivize business to make investments that economy. We also at the same time know that transforming our ener important. that's why the energy expertise by workers across this co initiatives like a recent agreement we signed on hydrogen for exampl will be essential for zero emissions vehicles of the future. when we ta china is right now a strong provider to the world of critical minerals. have strong and stable supplies of that as well that could be of use in There are many many conversations we have on strengthening our e in the future and that involves being ambitious as we have been in se 2030 but showing a very clear plan on how we are going to reach th committed to being net Zero by 2050, which is something actually we the House of Commons in Canada right now. Hopefully we will see th come together to support that Net Zero legislation so Canada can co leadership in fighting climate change".*

> **Dan Tsubouchi** @Energy_Tidbits · May 23
>
> More important to #Oil #NatGas co's in 2021 than @IEA #NetZero pathway? #G7 policymakers make new commitments on #EnergyTransition ie. regs/laws that are coming. Also warning needed acceleration to NetZero will lead to stranded #FossilFuels assets. #OOTT g7uk.org/g7-climate-and...

2 6 7

Dan Tsubouchi @Energy_Tidbits · Jun 13

#Reuters "#Shell weighs blockbuster sale of Texas shale assets". Permian is "core upstream asset" & 1 of 9 core assets. Have to sell #Oil assets if they want to comply with Dutch ruling. Would be big hit to cash flow. #OOTT #EnergyTransition

reuters.com/article/us-she...

> **Dan Tsubouchi** @Energy_Tidbits · Jun 9
>
> 
>
> 3/4. how else can they catch up but sell more #Oil assets? but need upstream cash flow, #Shell CEO says "need this financial strength" to invest in lower-carbon energy, etc. upstream IRR 20-25% vs top wind project 7% ... #NatGas #OOTT
>
> Show this thread

2 5 7

Dan Tsubouchi @Energy_Tidbits · Jun 13

great day in #Calgary. 25c and sunny. been a steady stream of rafts, kayaks and paddle boards enjoying the Elbow River

8

Dan Tsubouchi @Energy_Tidbits · Jun 13

Our weekly SAF June 13, 2021 Energy Tidbits memo was just posted to our SAF Group website. This 44-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 #OPEC #LNG safgroup.ca/insights/trend...

SAF GROUP

Energy Tidbits

June 13, 2021

Produced by: Dan Tsubouchi

Oil Demand Surge Happening, Both IEA and OPEC Forecast Q3/21 Demand +3.1 mmb/d QoQ And More in Q4/21

Welcome to new Energy Tidbits memo readers. We are continuing to add new readers to our Energy Tidbits memo, energy blogs and tweets. The focus and concept for the memo was set in 1999 with input from PMs, who were looking for research (both positive and negative items) that helped them shape their investment thesis to the energy space, and not just focusing on daily trading. Our priority was and still is to not just report on events, but also try to interpret and point out implications therefrom. The best example is our review of investor days, conferences and earnings calls focusing on sector developments that are relevant to the sector and not just a specific company results. Our target is to write on 48 to 50 weekends per year and to post by noon mountain time on Sunday.

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